



Appendix B

NATURAL GAS

Highlights

Increasing Supply. The U.S. natural gas industry has undergone changes of unprecedented magnitude and pace. U.S. natural gas production increased 33 percent between 2005 and 2013. Production has shifted from traditional regions, such as the Gulf of Mexico, toward onshore shale gas regions. Most important for infrastructure has been the rapid growth of production in the Marcellus and Utica Basins, a trend that is expected to continue out to 2030 (the time horizon under consideration for the Quadrennial Energy Review).

Increasing Demand. Long-term gas demand affects the pace of midstream infrastructure investment, as new pipelines require shippers to sign contracts to finance the expansion. The increased supply of natural gas at historically low prices has significantly changed the economics and use of natural gas for electric power and industrial uses. Gas demand for power generation has grown from 15.8 billion cubic feet per day (Bcf/d) in 2005 to 22.2 Bcf/d in 2013. Further drivers of demand growth include significant new investment in industrial facilities, low capital costs, and proposed regulations that could encourage fuel switching in some regions.

New Infrastructure. Existing system flexibility and latent pipeline network capacity is likely to mitigate the magnitude of future investment required. Recent investment trends and projects in development indicate that, in most regions, existing policy and investment mechanisms are addressing constraints as they emerge. Analysis suggests that demand growth from liquefied natural gas exports is unlikely to strain the system in ways that cannot be resolved by existing mechanisms.

Gas-Electric Interdependencies. As gas use for power generation increases, the interdependency between the gas and electricity sectors can create regional reliability challenges. Coordination between the two industries, including, for example, alignment of gas and electricity bidding and scheduling days, remains an issue that requires further attention. In some regions, gas-fired power generators lack incentives for procuring gas in time frames and at volumes that would provide market signals for gas industry infrastructure investment. Maintaining and improving the flexibility of the natural gas system through high-deliverability gas storage or gas-electricity system flexibility solutions (e.g., electric demand response; adding natural gas pipeline capacity, dual-fuel capability, and end-use energy efficiency; and adding electric transmission capacity) can assure not only the reliability and resilience of natural gas delivery, but of the electricity system.

Processing. Wet gas production requires more processing capacity for natural gas and more transportation capacity for NGL. In the Bakken, extraction of associated gas has been driven primarily by demand for tight oil, resulting in significant flaring when takeaway capacity and local use of associated natural gas and NGL is outpaced by production (see Appendix A (Liquid Fuels) for discussion of NGL). The State of North Dakota has implemented new regulations to reduce gas flaring, which will likely lead to the development of additional processing and gathering infrastructure in the state. National processing capacity is currently 83 Bcf/d and expected to increase to 95 Bcf/d by the end of 2017. This projected increase is expected to alleviate existing processing constraints for most regions of the United States, particularly in the Marcellus.

Climate and Environmental Implications. The growth in gas-fired power generation can reduce carbon dioxide and criteria pollutant emissions from power generation. Methane emissions contributed to roughly 10 percent of gross greenhouse gas emissions (on a carbon dioxide-equivalent basis) from U.S. anthropogenic sources; nearly one-quarter of which (or 2.5 percent of total U.S. carbon dioxide-equivalent emissions) were emitted by natural gas systems.^a More than two-thirds of those natural gas-related emissions of methane emissions from natural gas systems are from natural gas transmission, storage, processing, and distribution.

Public Safety. Natural gas distribution pipelines are responsible for the majority of serious gas pipeline safety incidents. These incidents tend to occur in densely populated areas. Excavation damage is the leading cause of serious incidents along natural gas pipelines; although, significant and preventable contributors also include equipment failure, incorrect operation, and pipeline corrosion.^b Natural gas distributors, who largely serve residential and commercial loads, face a need to refurbish

^a Environmental Protection Agency. "U.S. Greenhouse Gas Inventory." Table ES-2. 2014. <http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Chapter-Executive-Summary.pdf>. Accessed April 1, 2015.

^b Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Pipeline Incident 20 Year Trends." 2015. <http://www.phmsa.dot.gov/pipeline/library/datastatistics/pipelineincidenttrends>. Accessed February 25, 2015.

Highlights (continued)

or replace aging and leak-prone pipes, or make other system upgrades.^c Though the total costs of replacing these pipes is estimated to be many billions of dollars, replacement brings with it meaningful risk reduction and emissions mitigation.^d

Government Role. There are critical government roles across energy systems to help protect public and private interests with respect to reliability, safety, and environmental performance. Various government agencies work at the Federal, state, and local levels to help enable these goals, including through facility permitting, safety inspections, and market oversight—all of which is essential to prudent system development and operations.

^c Department of Transportation, Pipeline and Hazardous Materials Safety Administration. “2013 Gas Distribution Annual, from Form PHMSA F 7100.1-1 (rev 1-2011).” 2014.

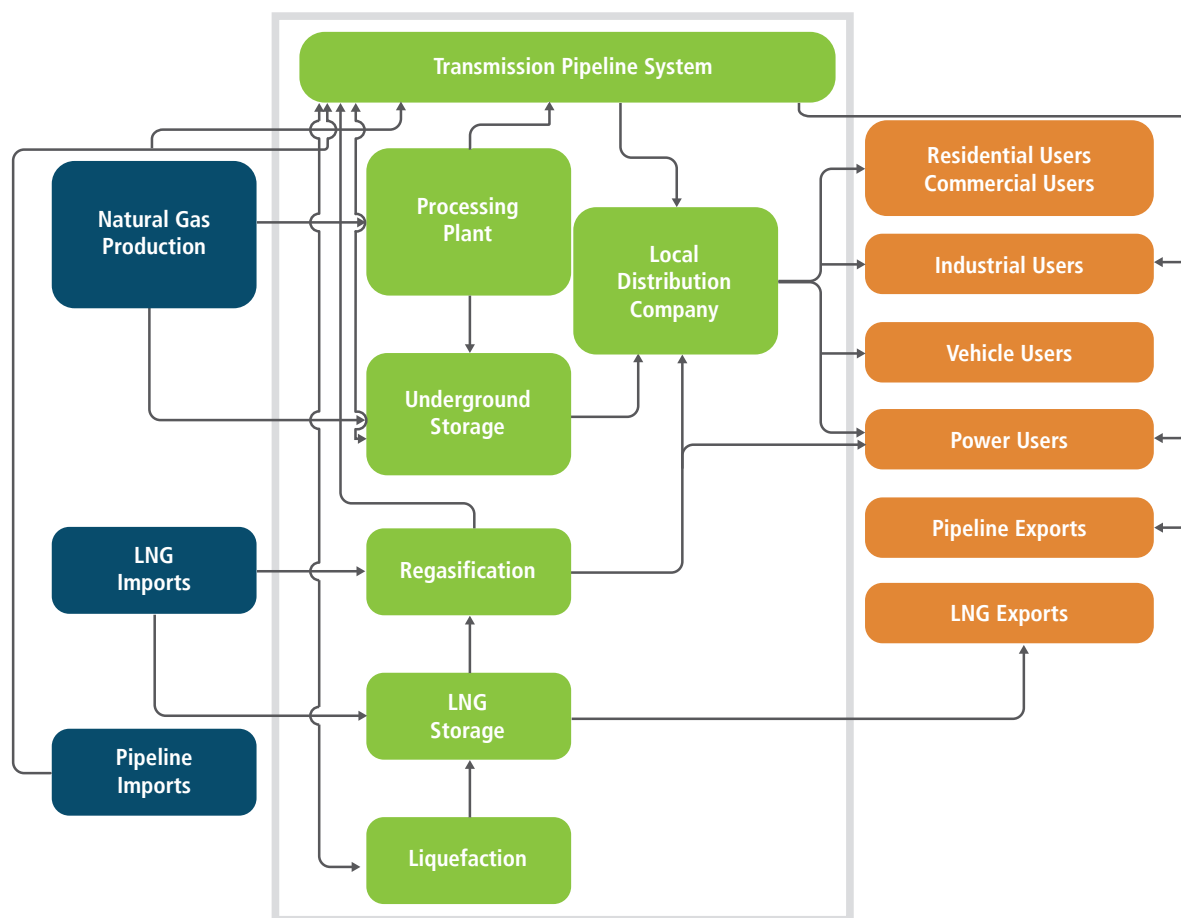
^d American Gas Association. “Managing the Reduction of the Nation’s Cast Iron Inventory.” 2013.

Introduction

This appendix focuses on the transmission, storage, and distribution (TS&D) systems for natural gas and begins with a description of the changing landscape of natural gas in the United States. This includes analysis of recent and projected increases in domestic gas production and the potential magnitude and unique attributes of sources of demand. From there, the infrastructure implications of changing supply and demand are analyzed and discussed by midstream project type: natural gas processing, transmission, storage, distribution, and export infrastructure. Following this system characterization are analyses and discussion of major attributes of the natural gas system as a whole, including natural gas and electricity interdependence, system resilience, pipeline safety, and emissions. Analysis of natural gas liquids (NGL) is included in the liquid fuels chapter of the Quadrennial Energy Review (QER).^e

Figure B-1 provides a schematic overview of the natural gas supply chain. The boxed area is the primary focus of this appendix. External factors such as production and market demand are also covered to provide context for analyzing system dynamics.

^e In November 2014, the Energy Information Administration released the report “Hydrocarbon Gas Liquids (HGL): Recent Market Trends and Issues,” which defined HGL (the organization’s proposed nomenclature for what are often referred to as NGL) and explored HGL supply, logistics, and markets. The report is available at www.eia.gov/analysis/hgl/pdf/hgl.pdf.

Figure B-1. Natural Gas Supply Chain, from Production and Imports to End-Use Customer

This QER is focused on the TS&D of natural gas, as indicated by the central section of the schematic.

The Changing Landscape of Natural Gas

In order to understand current market forces affecting the natural gas TS&D infrastructure, a brief discussion of natural gas production and demand changes is necessary. This section characterizes the recent increase in U.S. natural gas production and the emerging drivers of natural gas demand.

Recent changes in the natural gas industry have driven a geographic shift in how the industry operates, with recent production increases occurring in different locations from the main production areas of the previous several decades. In many cases, this new production meets nearby demand (such as power generation in the Northeast, or proposed liquefied natural gas (LNG) export terminals and industrial projects near the Eagle Ford and Haynesville Basins). This has reduced the need for new interstate pipelines to transport the gas to other regions.¹

Natural Gas Production

Traditionally, natural gas production has been classified as “conventional” and “unconventional” according to the type of geological formation from which the gas is extracted.^{1,2} The original focus of the oil and gas industry was on recovering conventional natural gas, which is found in formations with multiple porous

^f Natural gas may also be identified as dry or wet. Wet natural gas is rich in liquid hydrocarbons, such as oil and NGL. Dry natural gas is natural gas that remains after (1) the liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation), and (2) any volumes of non-hydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable.

zones and was historically easier to extract than unconventional natural gas.³ Unconventional natural gas encompasses three types: shale gas, coalbed methane, and tight gas.⁴

In 2004, the outlook for natural gas production and demand growth was poor, and prices were high compared with recent prices. By 2014, almost everything had changed for the U.S. natural gas industry, except the capacity constraints in New England (see Table B-1).

Table B-1. Changes to Natural Gas Markets and Infrastructure, 2004–2013⁵

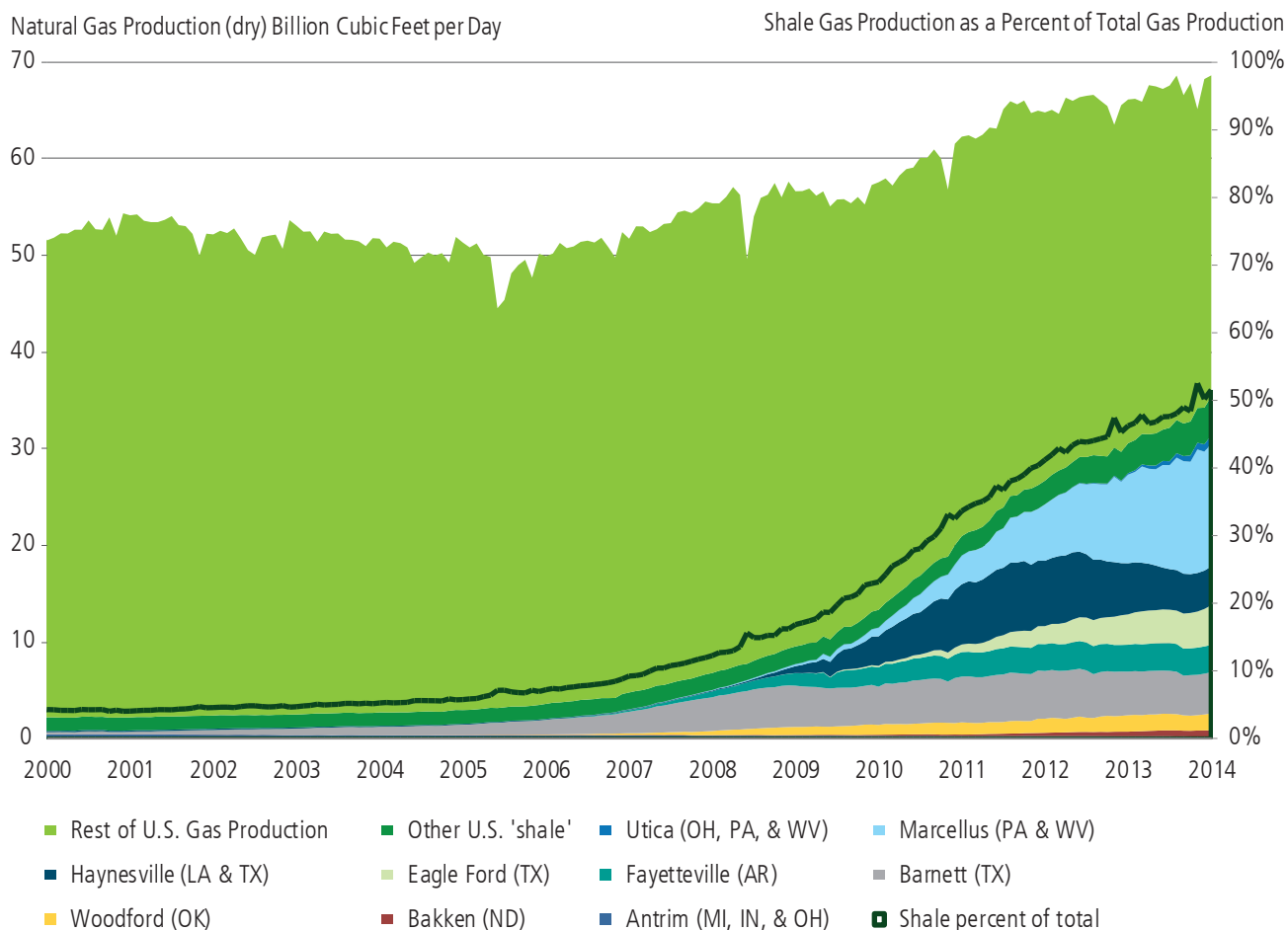
	2004	2013
Increase in Production (2004 and 2013)		
Annual Marketed Production	19.5 trillion cubic feet	25.7 trillion cubic feet
Projected Increase in Production (forecast time)	0.5 percent/year (2004–2030)	1.6 percent/year (2012–2040)
Shift in Geography of Production (% total marketed production) (2004 and 2013)		
Gulf of Mexico	20 percent	5 percent
Texas	26 percent	29 percent
Pennsylvania	1 percent	13 percent
Decrease in Prices^a at Henry Hub (2004 and 2013)		
Average Annual Price	\$5.89 per million British thermal unit (Btu)	\$3.73/million Btu
Daily Price Range	\$4.32–\$8.12/million Btu	\$3.08–\$4.52/million Btu
Increase in Natural Gas Use for Electricity Generation (2004 and 2013)		
Net Generation Fueled by Natural Gas	710,100 thousand megawatt-hours	1,113,665 thousand megawatt-hours
Percent of Total Net Generation Fueled by Natural Gas	17.9 percent	27.4 percent
	2004	2014
Changes to Natural Gas Markets and Infrastructure (2004–2013, 2014)		
New Terminals	10 import terminals	3 export terminals under construction ⁽¹⁾
Proposed Terminals	33 import terminals	43 export terminals in DOE permitting process
Constraints in New England (2004 and 2014)		
Daily Spot Prices^a	Reached as high as \$74/million Btu	Reached almost \$80/million Btu

^a Prices are in nominal dollars.

¹ This does not include Carib Energy, which received final approval but does not require export terminal construction. This facility exports product in small quantities to non-free trade countries.

This table provides a sampling of metrics that reflect the significant changes in the U.S. natural gas system over the past 10 years. Production has increased, most notably in the Pennsylvania area, which has led to shifts in transmission needs. The increase in production overall can be seen with the decrease in prices at Henry Hub, the shift in development from LNG import to export terminals, and the increased use of low-cost gas in electricity production.

Infrastructure has been built up substantially over the past decade. From 2004 to 2014, companies made \$10 billion in average annual investments in midstream natural gas infrastructure, including major pipeline projects.⁶ Investment in natural gas processing in the United States was \$7.5 billion in 2013.⁷

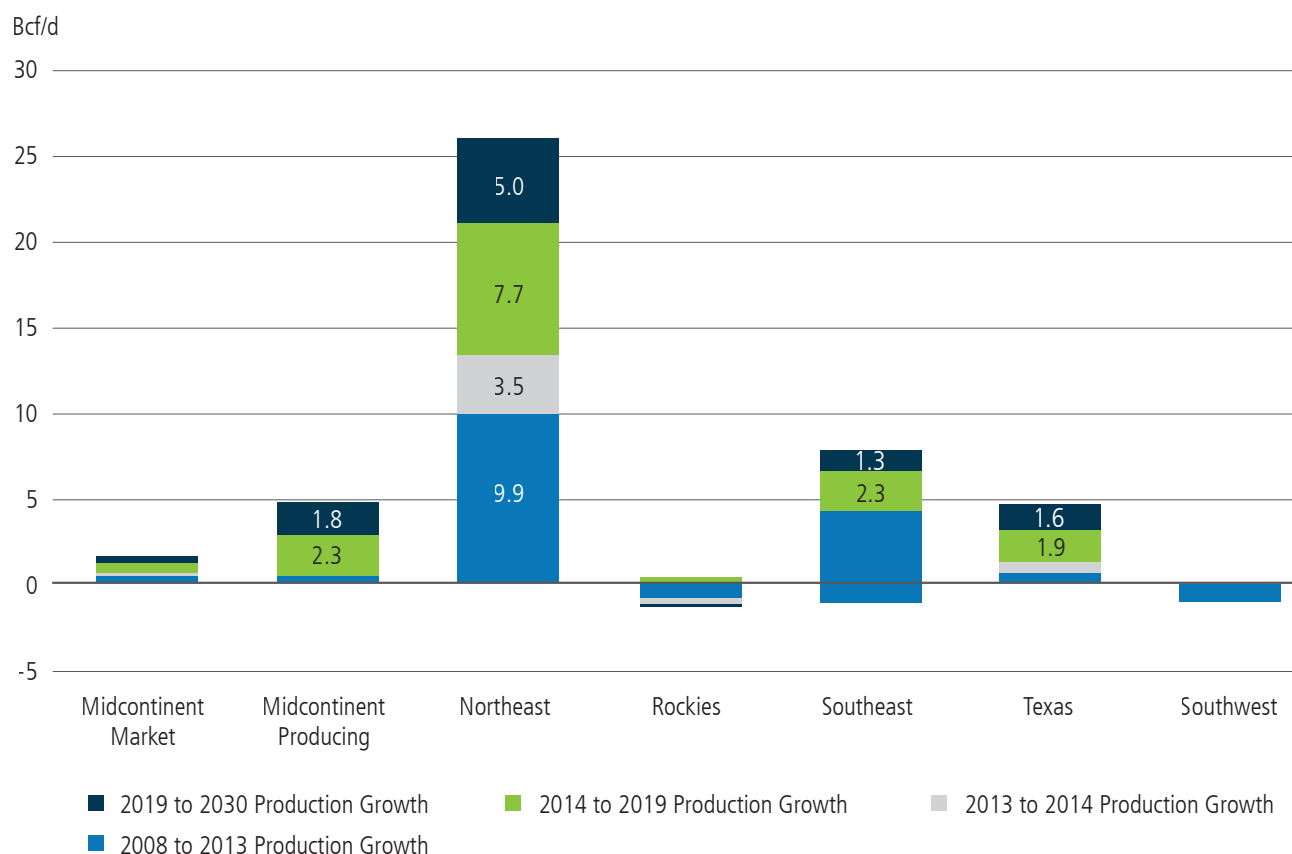
Figure B-2. Trends in U.S. Natural Gas Production by Play and Type, January 2000–April 2014^{8,9}

Shale gas has emerged as a significant portion of overall U.S. gas production.

Enabled by new technology, especially the combination of horizontal drilling and hydraulic fracturing, the U.S. natural gas industry has undergone unprecedented changes over the past 8 years. Increased shale production has come in a series of waves (see Figure B-2). From 2005 until 2009, most of the increase in production came from the Barnett Basin in east Texas.¹⁰ Beginning in 2009, production stabilized in the Barnett Basin and increased rapidly in the Haynesville Basin in Louisiana and east Texas.¹¹ In 2012, production shifted to the Marcellus Basin in Ohio and Pennsylvania and the Eagle Ford Basin in south Texas.¹² Production in the Haynesville Basin fell as producers moved to the more profitable basins. Analysis conducted by the Department of Energy's (DOE's) Office of Energy Policy and Systems Analysis (EPSA) projects that the most significant increases in production through 2030 will occur in the Northeast (Marcellus and Utica) (see Figure B-3).¹³

While the long-term production trend remains highly uncertain, the growth trend is expected to continue through 2030, with dry natural gas production at 66.5 Bcf/d in 2013¹⁴ and forecasted to increase to more than 93.5 Bcf/d by 2030.¹⁵ In particular, the Marcellus, Eagle Ford, Anadarko, Utica, and Haynesville Basins are expected to see the highest incremental production.

Figure B-3. Production Growth by Region, 2008–2030 (Bcf/d)¹⁶



Increased production in the Northeast is expected to dominate U.S. production growth out to 2030.

Geographical Shift in Natural Gas Production

Conventional natural gas production in the United States has fallen over the past decade by about 14 billion cubic feet per day (Bcf/d), but overall natural gas production has grown significantly as a result of increased shale gas production (see Figure B-2).¹⁷

Natural gas has been produced from shale formations since the 19th century; however, until recently, the amounts were fairly small (see Figure B-4 for current and prospective shale plays). In 2004, shale gas accounted for about 5 percent of the total natural gas production in the United States. Since then, shale gas production in the United States has grown more than tenfold from 2.7 Bcf/d in January 2004 to about 35.0 Bcf/d in May 2014.¹⁸ Total dry natural gas production in 2014 has grown 35 percent over the production level in January 2004 to 69 Bcf/d, and shale gas now accounts for about half of overall gas production in the United States.^{19, 20, 21}

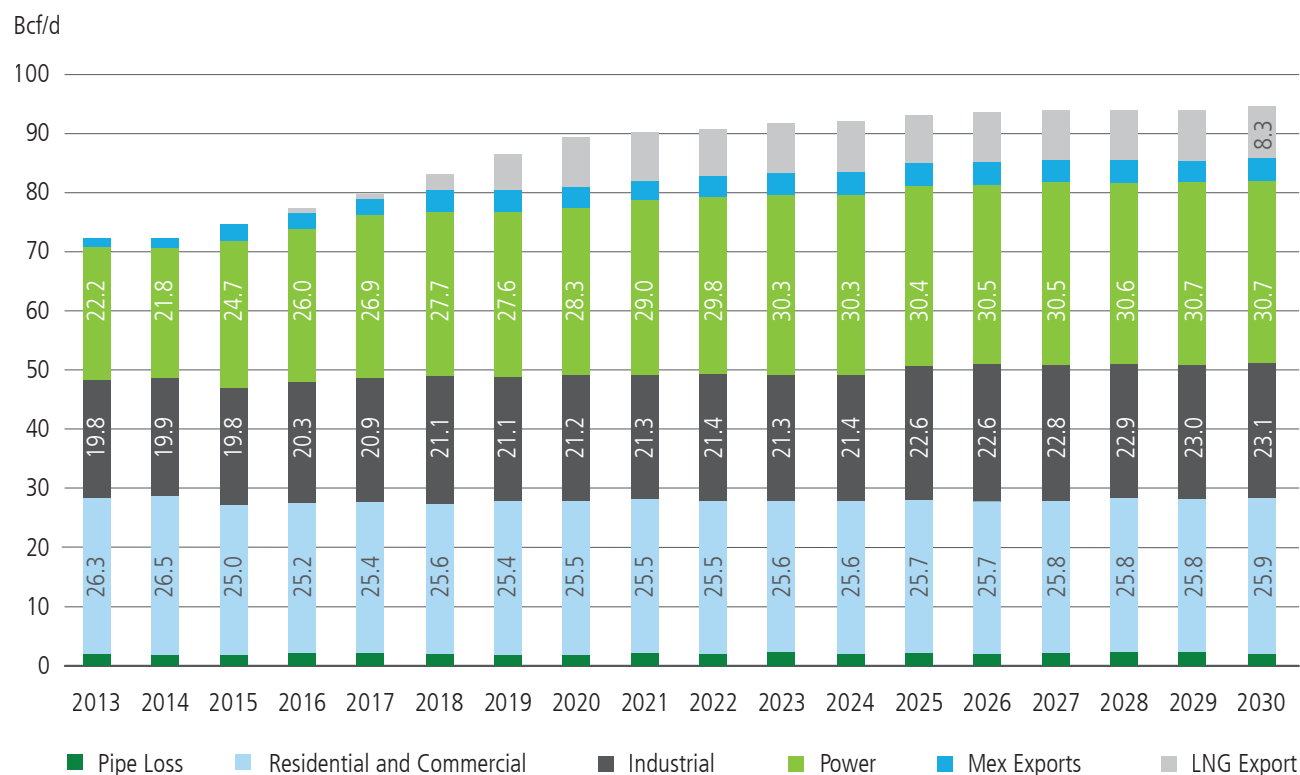
Figure B-4. Production Growth by Region, 2008–2030 (Bcf/d)²²

Shale gas plays are located across the United States and have led to a shift in the utilization of gas transportation infrastructure.

Increasing Demand

Three factors contribute to the majority of the projected increase in natural gas demand by 2030: electric power generation (+8.5 Bcf/d), industrial use (+3.3 Bcf/d), and exports (+10.1 Bcf/d).²³ These three demand components are discussed in the following section (and shown in Figure B-5). Residential and commercial natural gas demand is projected to remain relatively flat through 2030 as energy efficiency counterbalances customer growth impacts on demand.²⁴

Figure B-5. Natural Gas Demand Forecast, 2013–2030²⁵



Power generation, industrial use, LNG exports, and exports to Mexico are the primary drivers of projected increases in natural gas demand.

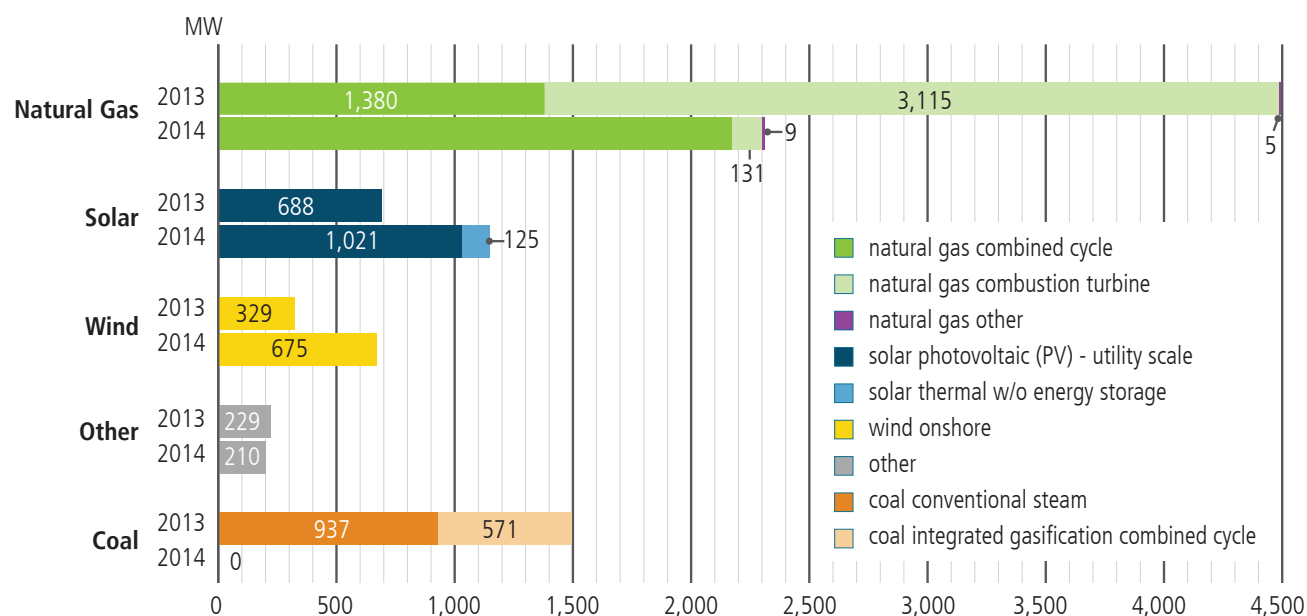
Demand Growth in Gas-Fired Power Generation

Plentiful domestic natural gas supply and comparatively low natural gas prices have changed the economics of electric power markets. Additionally, recent environmental standards at the local, state, regional, and Federal levels have encouraged switching to fuels with lower emissions profiles, including natural gas and renewables. U.S. natural gas demand for power generation grew from 15.8 Bcf/d in 2005 to 22.2 Bcf/d in 2013, and demand is projected to increase by another 8.9 Bcf/d by 2030.²⁶

Net gas-fired electricity generation increased 73 percent nationally from 2003 to 2013, from 650 terawatt-hours in 2003 to 1,126 terawatt-hours in 2013.²⁷ Trends in natural gas use for power vary by region because of differences in the availability of generating plants, generating plant age and efficiency, and the relative cost of fuels. Some regions saw larger rises; for example, net electricity generation from natural gas in the South Atlantic increased 204 percent between 2003 and 2013, while net electricity generation from natural gas in New England increased just 12 percent over the same time period.²⁸

Natural gas-fired power plants accounted for more than 50 percent of new utility-scale generating capacity added in 2013 (see Figure B-6).²⁹ Infrastructure changes will be needed to accommodate future growth in natural gas use for power, including repurposing and reversals of existing pipelines; laterals^g to gas-fired generators;³⁰ more looping and compression to the existing network; possibly some new pipelines; additional processing plants; and flexibility solutions, such as high-deliverability storage or other non-infrastructure solutions.

^g Small segments of pipelines designed to link gas-fired power plants to the natural gas pipeline system.

Figure B-6. U.S. Power Plant Capacity Additions, January–June 2014 vs. January–June 2013³¹

Power plant capacity additions in 2013 and 2014 were dominated by natural gas-fired generation.

As absolute demand for natural gas grows, the demand profile for gas is changing. Many gas-fired power plants use large amounts of natural gas over short periods of time throughout the day. A generator that is needed only to meet daily peak demand may not be dispatched until early afternoon, consuming no gas at one moment then drawing very large volumes the next. These swings in natural gas demands from pipeline infrastructure can be very large: at full output, one 700-megawatt (MW) natural gas power plant consumes as much natural gas on an hourly basis as the entire heating demand of a small city.^{32, 33, h}

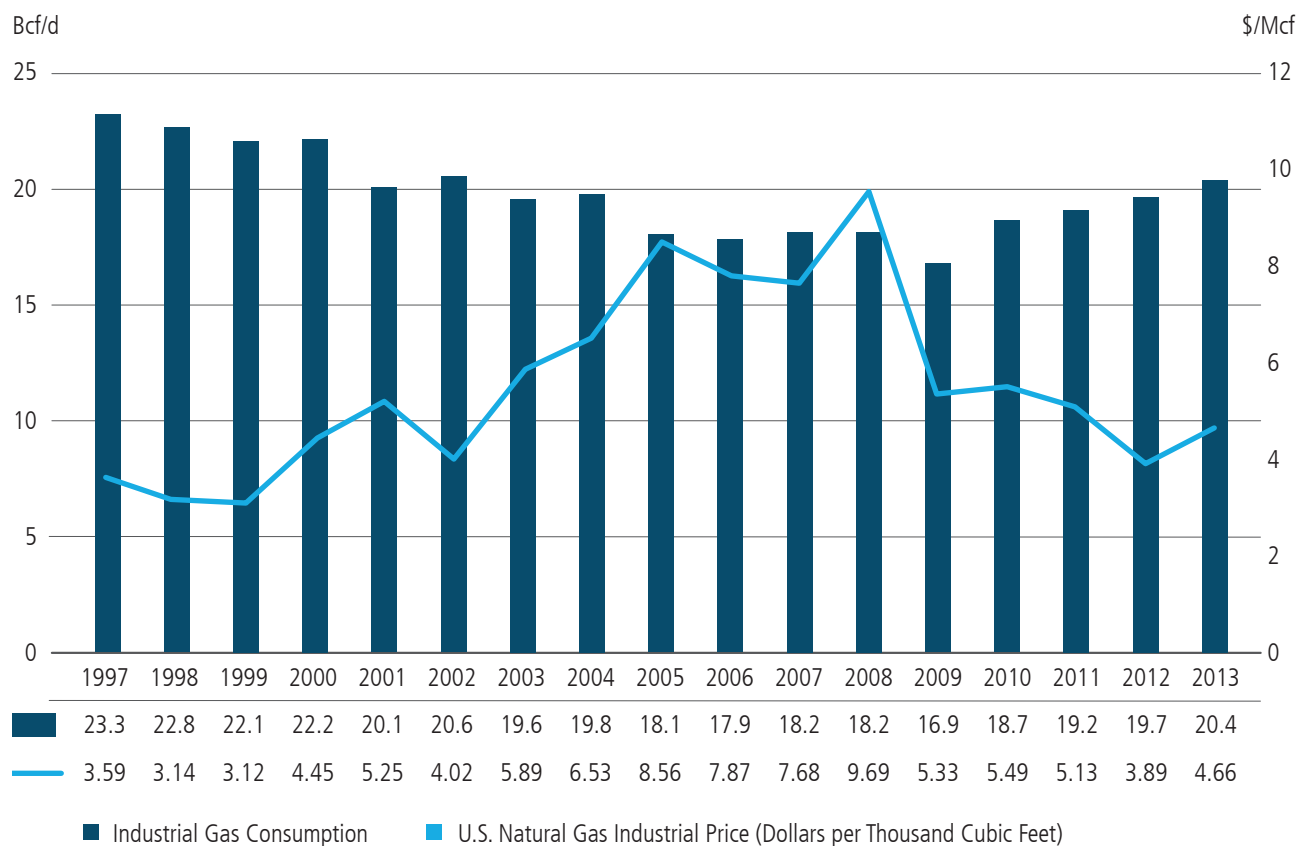
Demand Growth in Industrial Gas Consumption

Industrial gas consumption has increased in recent years due to the increased availability of low-cost gas. Investment increases in projects designed to take advantage of the significant low-cost gas available in the United States suggests this trend will continue (see Figure B-7).

Industrial demand growth is a significant potential source of natural gas demand, with a forecasted increase of 3.1 Bcf/d by 2030.³⁴ Similar to LNG exports, industrial natural gas demand is likely to have less seasonal variation than other sources of natural gas demand. Most of this activity is expected in the Southeast and Texas.³⁵ Four hundred twenty-four industrial projects representing 6 Bcf/d in natural gas demand have been announced. While not all of these may reach completion, they represent a significant increase in industrial demand.

^h A 700-MW power plant with a heat rate of 8,039 British thermal units (Btu) per kilowatt-hour consumes approximately 5,600 million Btu of natural gas per hour. In 2009, the average American household consumed 198,000 Btu per day. Therefore, on an hourly basis, a 700-MW power plant would consume the same amount of gas as 38,000 homes.

Figure B-7. Industrial Gas Consumption, 1997–2013^{36, i}



Industrial consumption varies inversely with price.

Demand Growth in LNG Exports

Exports are forecasted to be another significant source of natural gas demand. EPSA analyzed the output of multiple studies that relied on differing methodologies to identify a range of export scenarios. This included both bottom-up approaches based on current and planned LNG export terminals, as well as top-down approaches that considered national and international production and gas demand trends. By 2030, LNG export terminals in the United States and British Columbia, Canada, are projected to demand between 5.1 Bcf/d³⁷ and 8.3 Bcf/d of gas.³⁸ While there is a range of forecasted LNG export volumes, new pipelines and permitting are likely to be required for any scenario.

Impact of Unconventional Gas on Pricing Dynamics

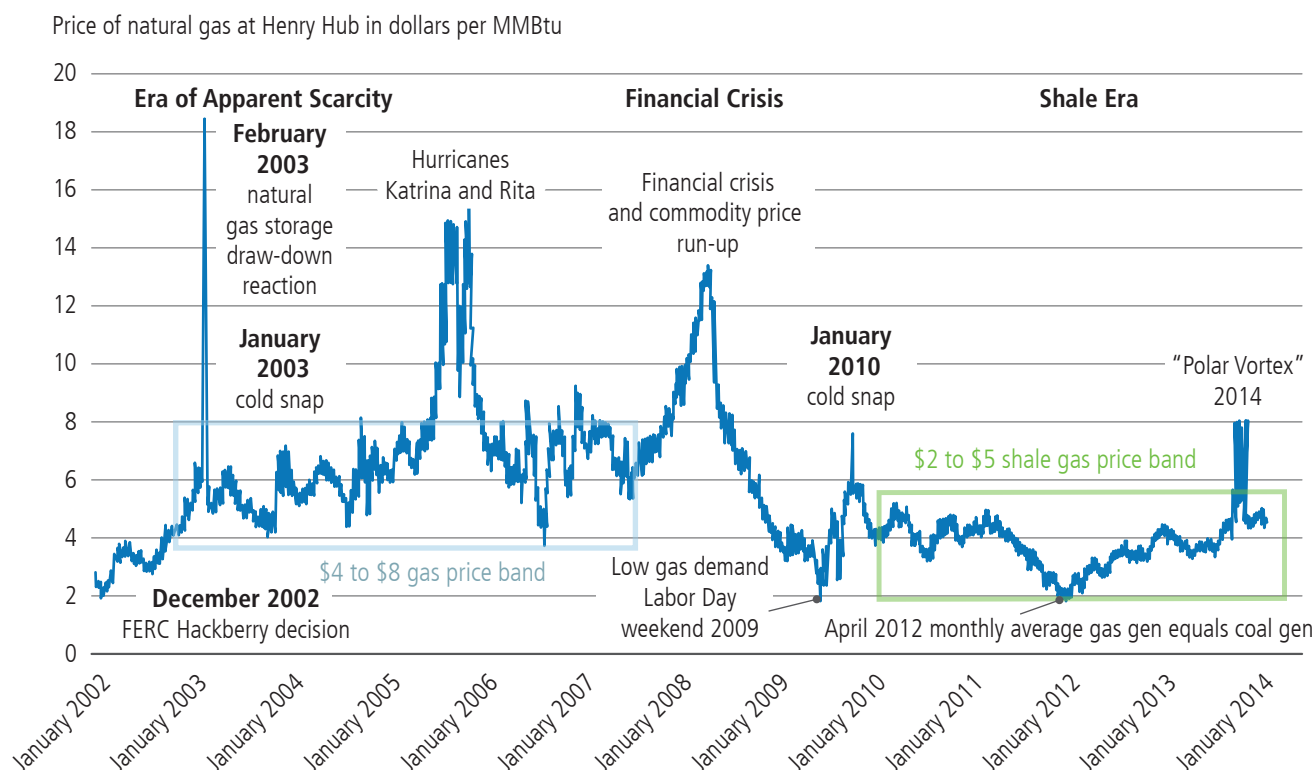
The recent increase in domestic gas production has impacted natural gas markets and the broader economy. In particular, the increase in shale gas production has led to decreased gas price volatility overall and lower average prices.

Prior to shale drilling technology breakthroughs, the United States appeared to be entering a time of increasing scarcity of natural gas, leading to high natural gas prices throughout the country. From 2003 to 2007, prices at Henry Hub typically oscillated between \$4 per million British thermal unit (Btu) and \$7 per million Btu.³⁹ Prices fluctuated with weather conditions and rose considerably following Hurricanes Katrina and Rita in 2005 (see Figure B-8).

ⁱ Prices are in nominal dollars.

Shale production increased between 2007 and 2009 and transformed the natural gas price regime. The market volatility that resulted from the financial crisis in 2008 initially masked this change in price structure. Natural gas prices rose to high levels in the first half of 2008 and then declined to low levels later in the year. Since that time, natural gas prices have traded in a band between about \$2 per million Btu and \$5 per million Btu.⁴⁰

Figure B-8. Natural Gas Spot Market Price at Henry Hub (\$/million Btu) Price Chronology, 2002–2014^{41, j}



Shale gas production has led to lower spot market prices and reduced price volatility. Daily spot prices for flow day are from Bloomberg, while price data comes from the Intercontinental Exchange.

Substantial low-cost supply growth has driven prices down. The Henry Hub price is the benchmark for U.S. natural gas prices. Average annual spot prices at Henry Hub fell 55 percent between 2005 and 2013. Henry Hub spot prices averaged \$3.73 per million Btu in 2013 and daily spot prices ranged from \$3.08–\$4.52 per million Btu that year.⁴²

While the "Shale Era" has resulted in lower average prices for natural gas, prices still fluctuate in response to weather. For instance, prices were low in spring 2012 due to warm winter conditions.⁴³ Following the relatively mild winter, natural gas storage facilities were considerably fuller than usual, and there was less demand for natural gas to inject into storage in the spring and summer.⁴⁴ Prices in 2012 fell so low that natural gas was at times able to compete with Western coal as fuel for electricity generation in markets like the Southeast, and natural gas-fired generation was dispatched equally to coal in April 2012. Conversely, prices have remained at the high end of their multi-year range in 2014 following extreme cold conditions in the winter of 2013–2014. Following the southward shift of the polar vortex (extreme and persistent cold winter temperatures) in early 2014,⁴⁵ natural gas storage facilities were relatively depleted and demand for gas to inject into storage has been high, resulting in relatively high prices in summer 2014.⁴⁶

^j Prices are in nominal dollars.

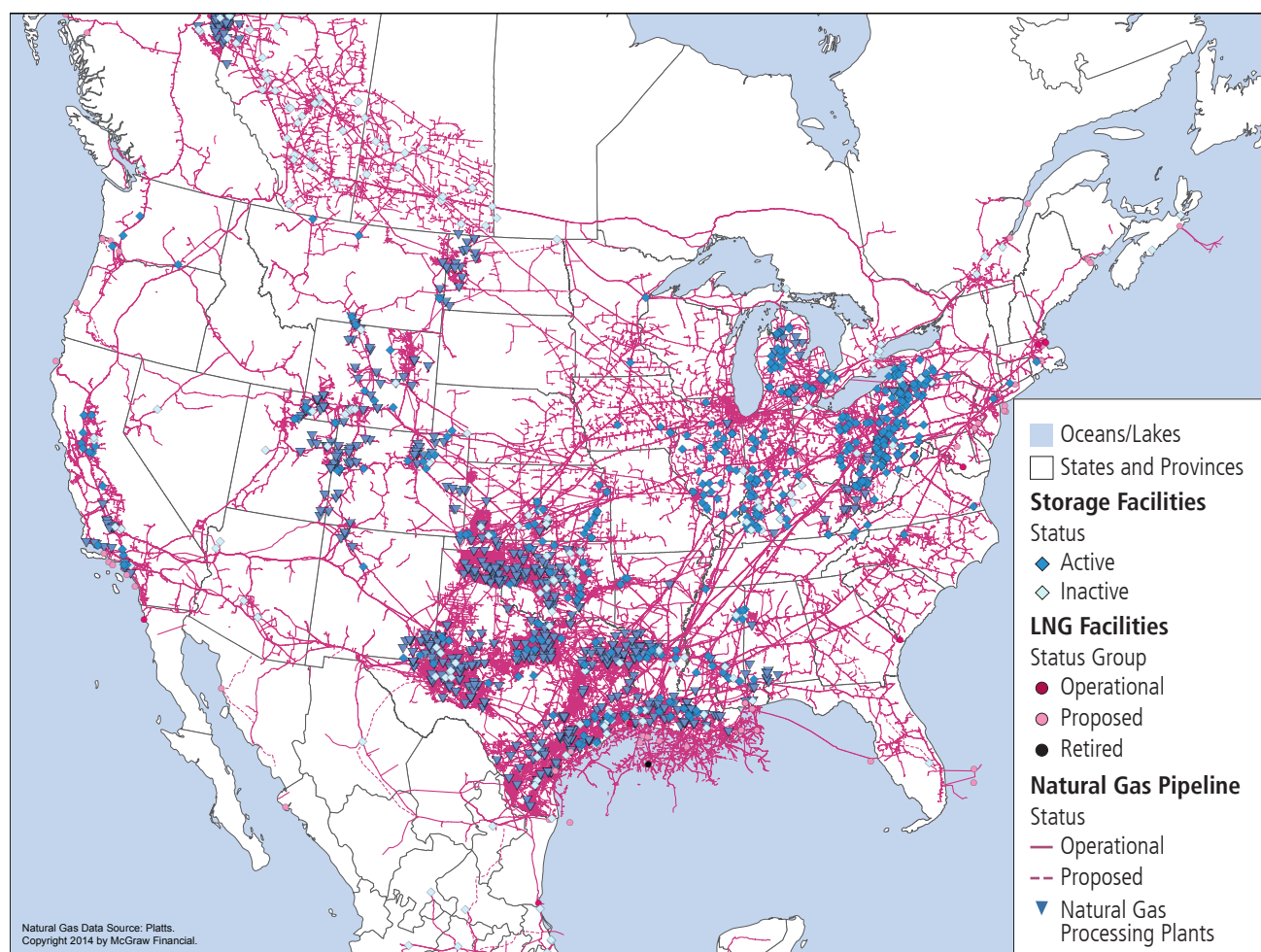
TS&D Infrastructure

The following section analyzes the midstream gas infrastructure implications of the changing natural gas production and demand trends described in Part I of this appendix. This includes natural gas storage, LNG terminals, processing capacity, high-pressure transmission pipelines, and local gas distribution networks (see Table B-2). The natural gas production, transmission, and distribution system is shown in Figure B-9.

Table B-2. Summary of U.S. Natural Gas TS&D Infrastructure⁴⁷

Infrastructure Type	Summary
Natural Gas Wells	482,822 producing wells
Natural Gas Plants	516 processing plants; Total capacity: 64,659 million cubic feet per day
Natural Gas Pipelines	~210 pipeline systems 315,000 miles of transmission pipeline
Underground Storage	414 storage facilities / 9.0 trillion cubic feet capacity
LNG Facilities and Import/Export Terminals	110 LNG facilities - mostly storage for peak shaving and backup. 11 import terminals (17.6 billion cubic feet per day capacity) (3 with import/export capability) 3 export terminals (7.3 billion cubic feet per day capacity)
Propane Storage and Delivery	13,500 bulk/storage distribution sites
Propane Stocks	141 terminals ~37 million barrels

The natural gas infrastructure includes wells, processing plants, pipelines, storage, and LNG facilities.

Figure B-9. Natural Gas Transmission and Storage Infrastructure in the North American Market⁴⁸

The United States possesses a significant natural gas storage and transmission network that provides flexibility to manage changes in supply and demand.

Natural Gas Processing Plants

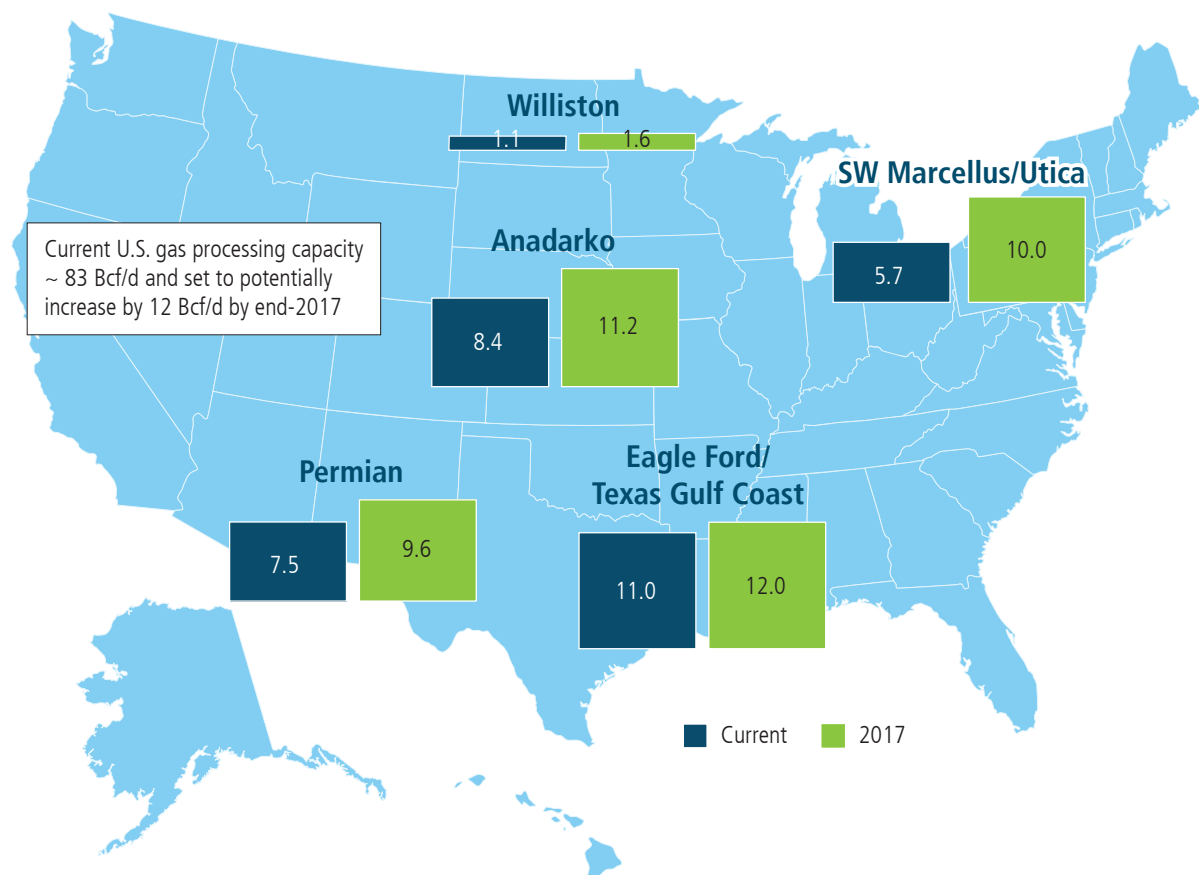
Processing plants are midstream facilities that process wellhead gas to generate ‘pipeline quality’ dry natural gas.^{k, 49, 50} They serve as a critical link between natural gas production and end use. Gas processing plants bring natural gas to pipeline quality levels and recover marketable products like condensate, NGL, liquefied petroleum gas, and sulfur. After processing plants remove liquid components and impurities from natural gas, the natural gas can be injected into transmission pipelines and transported to storage facilities, distribution systems, end users, and LNG terminals.⁵¹ The infrastructure implications of increased NGL production are explored in Appendix A (Liquid Fuels).

The movement of natural gas is constrained by the current capacity and geographical layout of the processing infrastructure, and natural gas processing capacity has expanded rapidly in recent years in response to increased production of natural gas.⁵² The United States is now in the midst of a rapid expansion of its gas processing capacity. U.S. natural gas processing capacity increased about 12 percent between 2004 and 2009

^k Raw natural gas typically is processed before it can be transported by interstate pipelines.

(not including Alaska). In 2012, the Energy Information Administration (EIA) reported that the lower 48 states had 516 active natural gas processing plants with a total processing capacity of 64.7 Bcf/d.⁵³ On average, these plants processed about 44.4 Bcf/d in 2012 (operating at about 69 percent of capacity).⁵⁴ In 2014, DOE analysis estimated that there was 83 Bcf/d of gas processing capacity (see Figure B-10). Most of the natural gas processing plants in the United States are centered near production regions in the Gulf of Mexico, Midcontinent, Texas, and the Rockies.⁵⁵ Texas led the country in natural gas processing capacity additions since 2004,⁵⁶ as well as overall capacity in 2013 with more than 18 Bcf/d of capacity.^{57, 58} In addition, there is a large processing plant near Chicago. This Aux Sable plant processes wet gas from Canada and supplies pipeline quality gas to several main East, West, and South pipelines.

Figure B-10. Natural Gas Processing Capacity⁵⁹



Substantial new natural gas processing capacity is likely to enter service before 2018.

Processing Capacity Build-Out

Processing capacity additions have lagged wet gas production in unconventional plays. Rapidly increasing extraction of liquids-rich natural gas from regions like Eagle Ford and Marcellus will require additional processing facilities. In the Marcellus and Utica, as of mid-2014, more than 1,500 wells had been drilled but not completed in large part due to the lack of processing and transmission capacity.⁶⁰ Many companies have announced plans to construct new natural gas processing plants. Most of the new processing plants will be located near important shale plays, especially in Eagle Ford, the Anadarko, Permian in west Texas, and parts of the Marcellus. In addition, gas processing constraints have also emerged in the Bakken, contributing to gas flaring. A key feature of many shale gas formations is that they produce “wet” natural gas—or natural gas that is rich in liquid hydrocarbons such as oil and NGL. Currently, these byproducts increase the total revenue

generated from shale gas wells because oil and some NGLs are more valuable than natural gas, which has led producers to increasingly focus on developing plays with shale oil and liquids-rich shale gas.⁶¹ In the Bakken, extraction of wet gas has been driven primarily by demand for tight oil, resulting in significant flaring when takeaway capacity and local use of associated natural gas and NGLs are outpaced by production. Current U.S. gas processing capacity is 83 Bcf/d and is expected to increase by 12 Bcf/d by the end of 2017. In the Northeast, currently planned projects would almost double capacity by the end of 2016 (see Figure B-11).⁶² IHS and ICF estimate total required gas processing investments from 2014 through 2025 at \$32 billion and \$14 billion, respectively.^{63, 64}

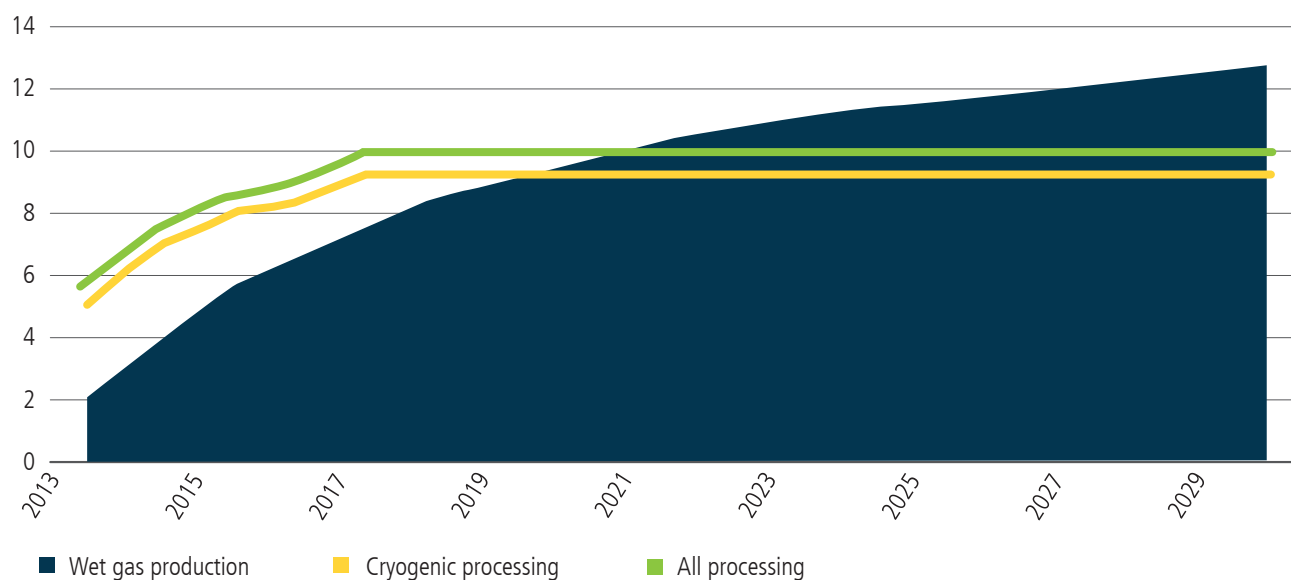
These new projects are expected to alleviate existing processing constraints and, in most cases, are unlikely to require additional government action beyond those included in the existing permitting process. Where project economics make sense, new processing plants are being built. However, where oil economics dominate production decisions, such as in North Dakota, new state actions may be necessary to develop the appropriate processing and gathering infrastructure. In particular, the North Dakota Industrial Commission has set goals to reduce flaring to 26 percent from the reference level by the fourth quarter of 2014, 23 percent by the first quarter of 2015, 15 percent by the first quarter of 2016, and 10 percent with the potential for 5 percent by the fourth quarter of 2020. The North Dakota Industrial Commission also requires companies to submit plans for which they will be held accountable for flaring reductions.⁶⁵

Figure B-11. Planned Processing Capacity Additions⁶⁶

a.

Northeast

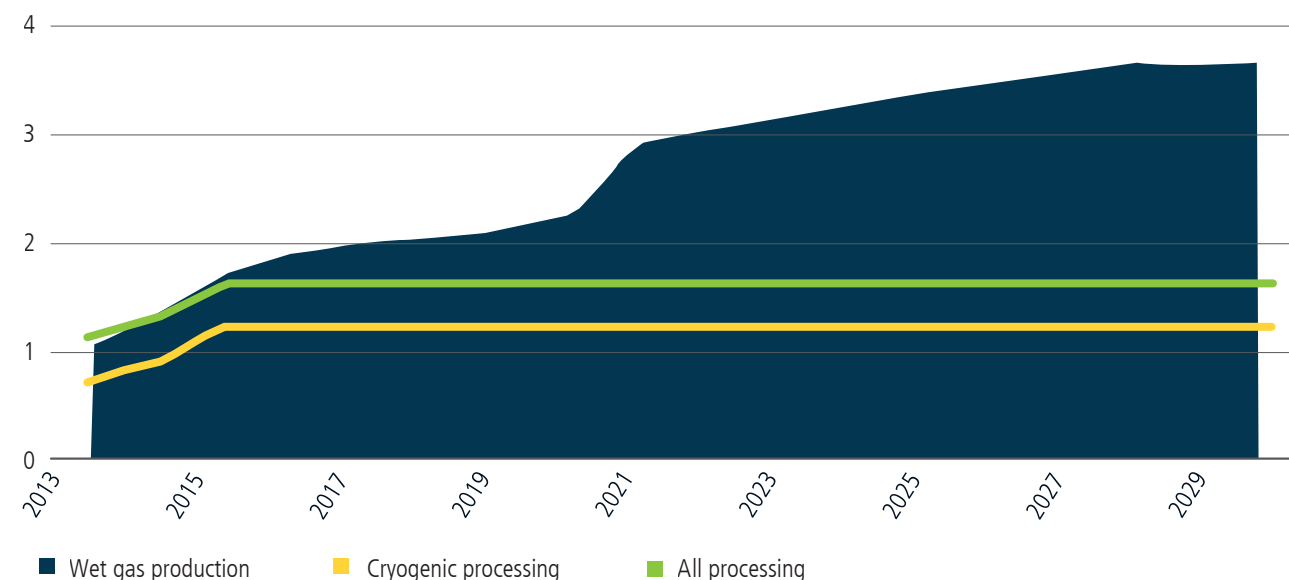
Bcf/d



b.

Williston

Bcf/d



Planned processing capacity additions in the Northeast are expected to be sufficient to manage increased wet gas production. Planned capacity additions in the Williston Basin may not be sufficient to address projected wet gas production increases.

Natural Gas Storage

Natural gas storage provides the means for balancing between steady production and variable demand. Storage can be divided into three categories: seasonal storage to respond to annual demand cycles, high-deliverability storage to meet immediate needs, and peak-shaving facilities—typically expensive, aboveground storage facilities—used to manage high winter demands in places without other forms of storage.

Underground Storage Facilities

Underground storage is the primary means for storing natural gas and offers both seasonal and high-deliverability storage. Underground natural gas storage systems were established as a cost-effective way to meet high demand during winter without increasing pipeline capacity. There are three main types of underground storage: depleted reservoirs, aquifer reservoirs, and salt caverns. Each type of storage has advantages and disadvantages (see Table B-3).

Table B-3. Types of Storage and Their Advantages and Disadvantages⁶⁷

Type	Primary Application	Storage Need	Cushion Gas (% of Total Capacity)	Injection Period (Days)	Withdrawal Period (Days)	Advantages and Disadvantages
Depleted Reservoir	Residential and Commercial	Seasonal demand	50%	200–250	100–150	+ Simple and relatively inexpensive to establish - Exist in limited geography
Aquifer Reservoir	Residential and Commercial	Seasonal demand	50%–80%	200–250	100–150	- Less retrievable gas, large cushion required - Exist in limited geography
Salt Cavern	Power Generation	Short-term variable demand	20%–30%	20–40	10–20	+ High deliverability - Exist in limited geography - High capital cost

The utilization of particular types of natural gas storage depends on geography, deliverability characteristics, and market.

While depleted fields are concentrated in areas with oil and gas production, aquifers are spread throughout the United States, and salt caverns require salt deposits, which are regionally concentrated. Depleted fields are easily converted for storage. Aquifers are bounded partly or completely by water bearing rocks where nature of the water in the aquifer may vary from fresh water to nearly saturated brines.⁶⁸ Adding to their expense, aquifers require larger amounts of cushion gas, or gas that is required to maintain a pressure threshold that will allow for extraction, and therefore have less retrievable inventory at any given time. Salt caverns have higher deliverability, but require greater initial investment to establish a storage space. The use of salt caverns has grown in the past decades as initial investments are recovered through savings on later extraction costs.⁶⁹ Salt cavern storage is geographically limited to salt deposits, which exist in the Gulf, Pennsylvania, Ohio, Michigan, and parts of the Midwest and Southwest.⁷⁰ The majority of existing salt cavern storage is in the Southeast, but salt caverns also have been leached from bedded salt formations in Northeastern, Midwestern, and Southwestern states.⁷¹

There are two important measures for natural gas storage: how much gas can be retrieved (Bcf) and how fast the gas can be retrieved (Bcf/d). A reservoir’s “working gas” capacity denotes how much of the stored gas is actually retrievable. Underground storage reservoirs are pressurized. Some of the stored gas, known as “cushion gas,” is required to maintain a pressure threshold that will allow for extraction. So, while a reservoir might contain gas, it becomes unrecoverable without enough pressure. The maximum daily delivery rate (or deliverability) indicates how quickly the gas can be extracted from the reservoir. This rate varies depending on the reservoir type (see Table B-4).

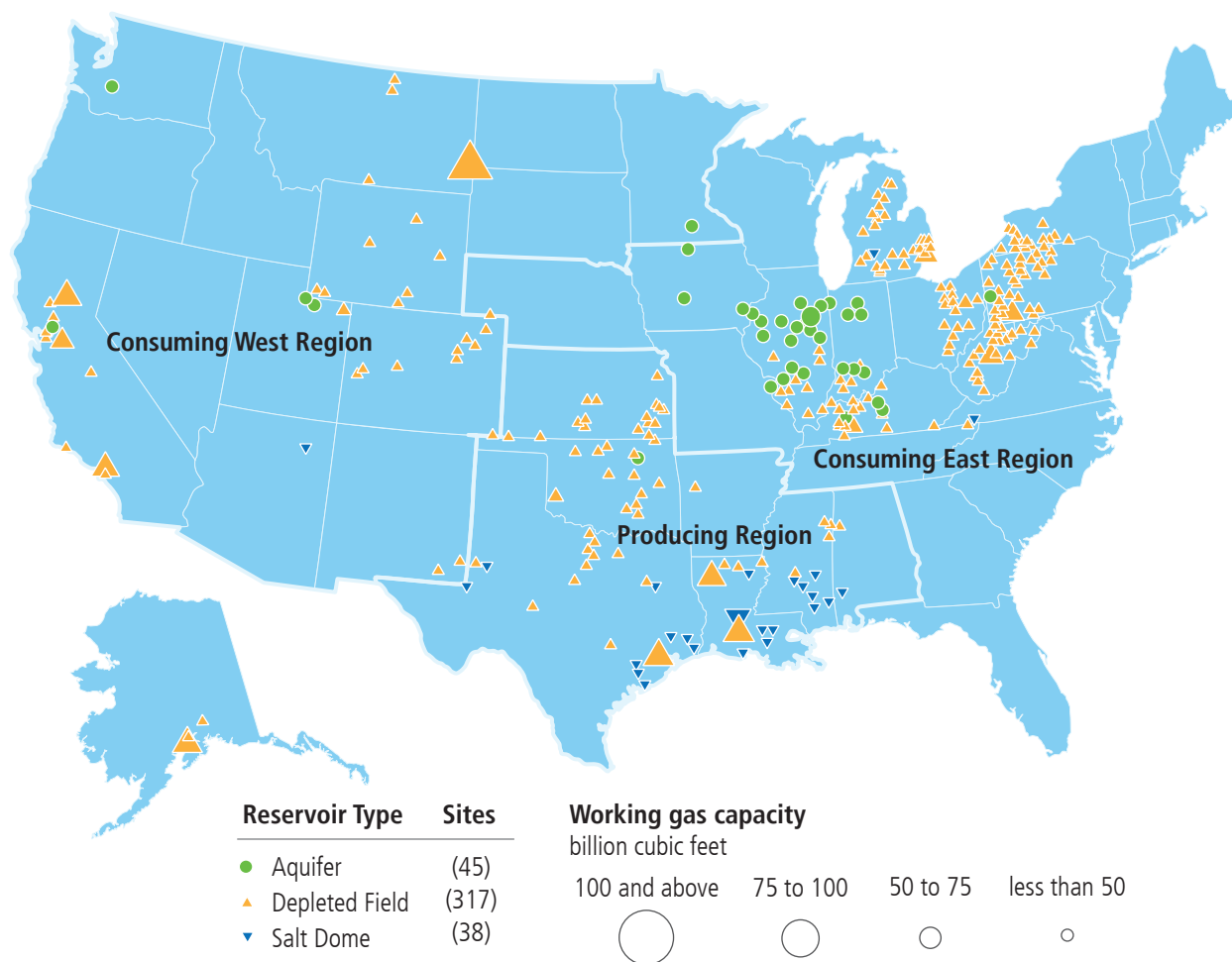
Table B-4. Deliverability (Bcf/d) and Working Gas Capacity (Bcf) of Underground Storage Facilities, 2012⁷²

Underground Storage Type (Number of Sites)	Deliverability (Bcf/d)	Proportion of Total Deliverability	Working Gas Capacity (Bcf)	Proportion of Total Working Gas Capacity
Depleted Fields (330)	73	66%	3,721	81%
Aquifers (44)	9	8%	367	8%
Salt Caverns (40)	29	26%	488	11%
All Underground Storage (414)	111	100%	4,576	100%

How much gas can be retrieved is a reservoir’s working gas capacity, while the deliverability denotes how fast the gas can be retrieved. Both of these values vary depending on the type of underground storage.

U.S. underground gas storage facilities include 414 reservoirs with a combined working gas capacity of 4.6 trillion cubic feet (Tcf). Of this, 3.7 Tcf is from depleted fields, 0.37 Tcf from aquifers, and 0.49 Tcf from salt caverns.⁷³ The most working gas capacity is found in Petroleum Administration for Defense District (PADD) II with 1.76 Tcf, followed by PADD III at 1.20 Tcf, and PADD I with 0.84 Tcf. Underground natural gas storage reservoirs are predominantly established in areas that have markets consuming large quantities of natural gas nearby (Midwest, Northeast) and along major pipeline routes (see Figure B-12).

Figure B-12. U.S. Active Underground Natural Gas Storage Facilities by Type (February 28, 2014)⁷⁴



Depleted fields are spread throughout the United States. Aquifers and salt caverns currently are regionally concentrated in the Southeast and along the Gulf Coast. Salt cavern storage is geographically limited to salt deposits, which exist in the Southeast, Northeast, Midwest, and Southwest. The majority of existing salt cavern storage currently resides in the Southeast, but salt caverns also have been leached from bedded salt formations in Northeastern, Midwestern, and Southwestern states.

Natural gas underground storage inventories are expected to stay below their 5-year average until LNG exports start in the 2017 through 2019 time frame. Storage may increase in response to increased LNG exports.⁷⁵ EPSA analysis anticipates some interregional expansions to the Southeast will provide 10.1 Bcf/d of gas on 9.7 Bcf/d of incremental demand.⁷⁶ These tight supply conditions, in conjunction with a number of other market factors, could create upward price pressures during a colder-than-normal winter.

Aboveground Storage Facilities

LNG peak-shaving facilities are the primary means of storing gas in regions without the geological formations for underground storage. This is particularly the case for New England (see Figure B-9). Local distribution companies (LDCs) have built peaking plants to serve the peak loads on their systems (typically during the winter). Some of these plants (LNG peak-shaving plants) include facilities to liquefy natural gas, while others (satellite plants) receive shipments that have been liquefied elsewhere and delivered by trucks (see Table B-5). Concerns about regional natural gas shortages drove the construction of many non-export liquefaction plants. Natural gas distribution and transmission operators manage the fuel in their storage facilities by liquefying natural gas when demand is low to store until the price increases.⁷⁷

Table B-5. Peak-Shaving Facilities in the United States, 2013 ^{77, 78}

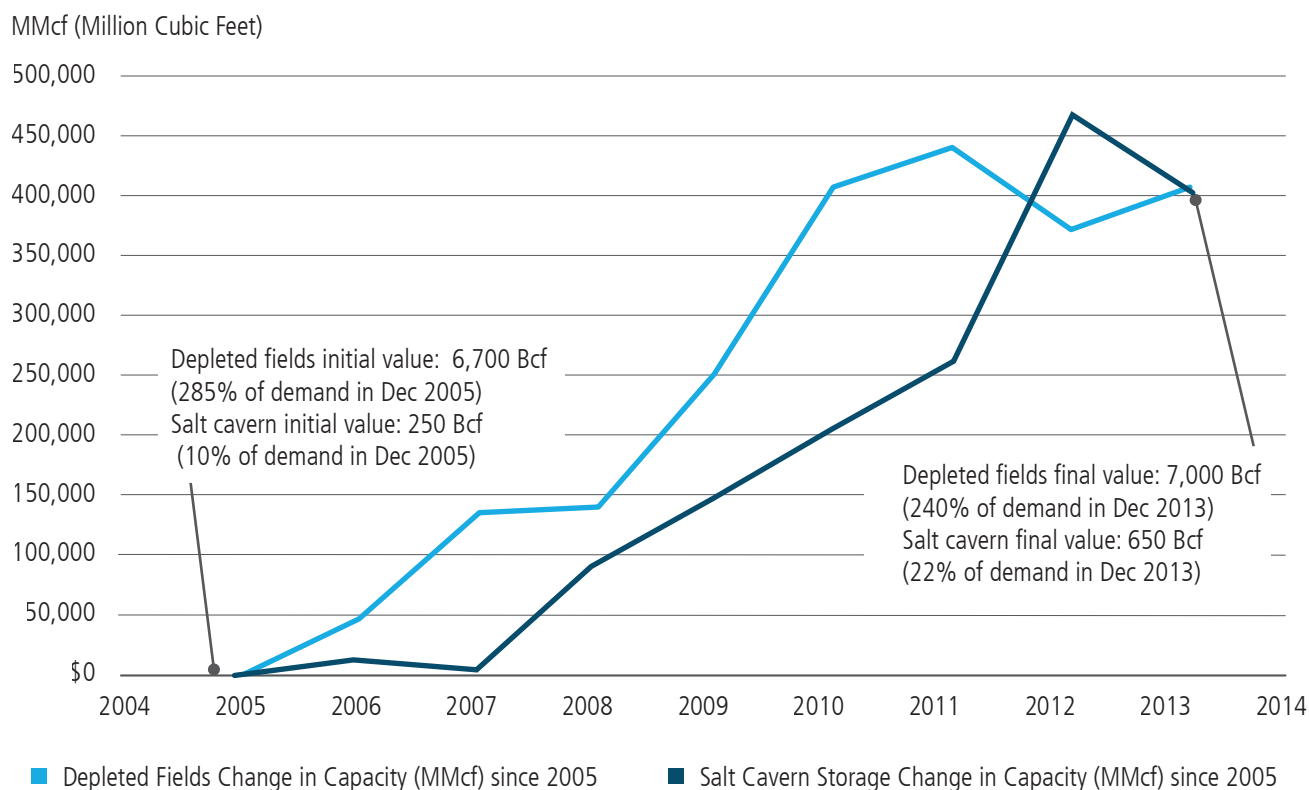
State	Capacity (MMcf/d)	Capacity (bbl)	Number of LNG Tanks
PA	202,876	1,878,952	5
MN	72,550	1,528,000	4
MA	20,924	2,938,137	21
WY	7,200	4,857	3
GA	1,204	1,935,000	5
NC	914	2,034,762	9
IN	610	1,566,000	4
NY	580	926,104	4
TN	570	1,276,000	4
NJ	430	625,000	3
IA	420	1,124,000	5
WA	322	693,523	6
MD	312	290,000	3
IL	300	580,000	2
CT	285	1,044,000	3
RI	222	678,450	3
OR	220	475,000	2
AL	200	525,000	3
VA	156	418,699	3
SC	150	550,000	3
NV	105	290,000	1
WI	94	150,000	2
ID	60	175,000	1
NE	60	290,000	1
DE	50	72,500	1
AR	36	55,000	1
Total	310,850	22,123,984	102

Pipeline and Hazardous Materials Safety Administration data show 102 tanks in the United States in 2013 that have LNG peak-shaving capabilities. Several states have additional LNG satellite tanks as well.

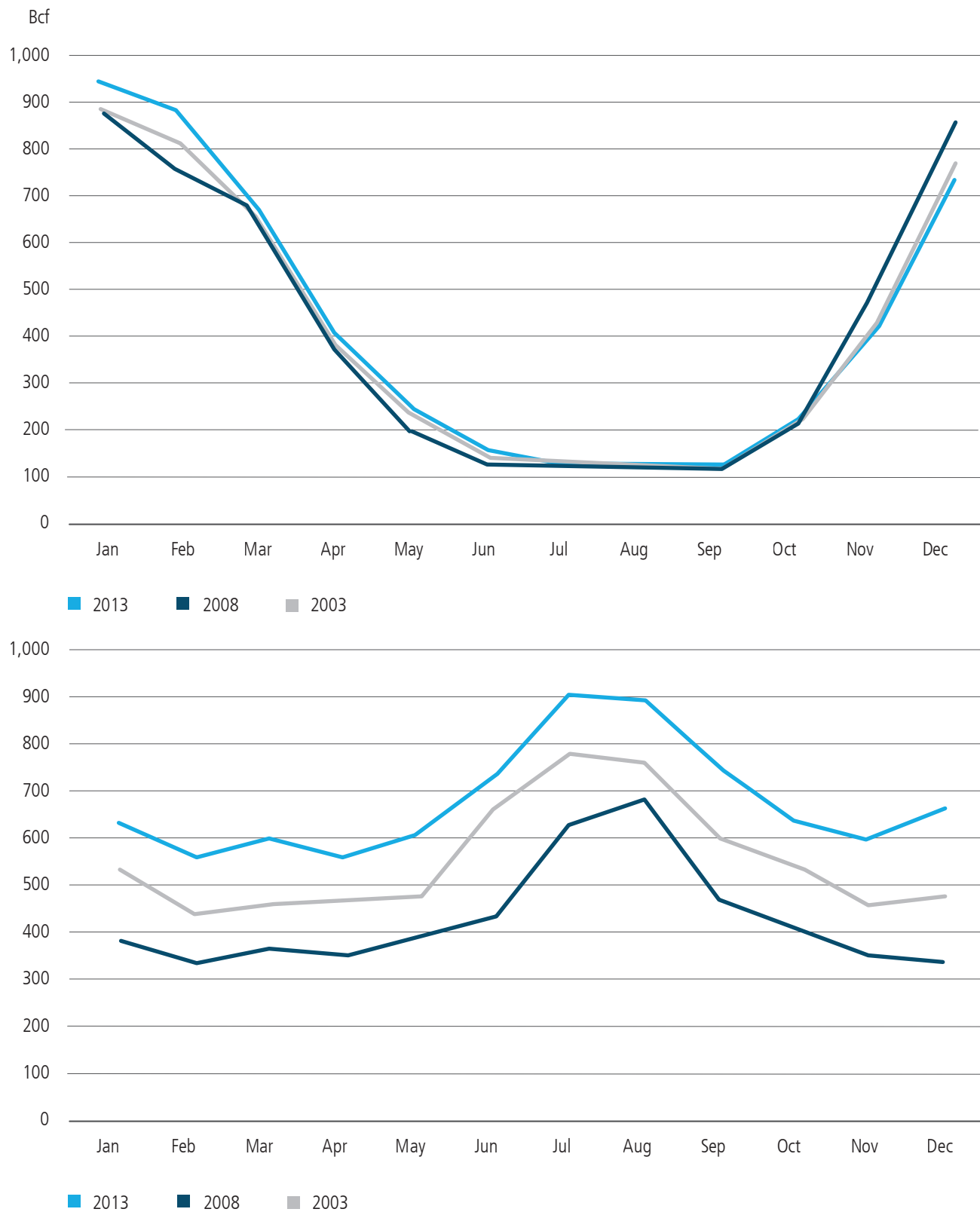
Natural Gas Storage Investment

While the current system exhibits a high level of resilience to disruptions, market incentives to build gas storage, critical to gas system resilience, have been lessening in recent years. Historically, storage capacity largely has been held by LDCs as an important part of the supply portfolio to meet peak loads, but it is now increasingly held by merchant operators. Storage that was previously valued primarily for reliability purposes is now valued primarily for its ability to arbitrage prices during a year. Like a financial option, storage is now valued on an intrinsic value (the seasonal price spread in futures prices) and an extrinsic value (largely unpredictable short-term price spikes). The Federal Energy Regulatory Commission (FERC) observed in 2005 that gas storage capacity had increased less than 2 percent over about 20 years, and during that same period, U.S. natural gas demand rose by more than tenfold that amount (24 percent).⁷⁹ From 2005 through 2013, underground aquifer and depleted field storage capacity have each increased by about 6 percent (see Figure B-13). Demands for storage, however, are affected by the changes in both production and consumption that have occurred over the same time period. The underground gas storage system is important during the summer months to serve the needs of natural gas-fired power plants to meet electricity demands (see Figure B-14 and the Natural Gas and Electricity Interdependence section for more details).

Figure B-13. Storage Capacity Additions by Volume Since 2005⁸⁰



Additions to storage capacity in depleted fields and salt cavern storage follow similar trends (comparable trends also can be seen with working gas storage). While the capacity of depleted fields as a percentage of demand has decreased over time, the percentage of salt cavern capacity as a percentage of demand has more than doubled. In recent years, expansion has stagnated (and even decreased for salt cavern storage). The drop in investment is in part due to the increase in gas production, as well as the collapse of seasonal gas price differentials.

Figure B-14. Monthly Natural Gas Consumption (Bcf) by the Residential Sector (top) and Power Sector (bottom)⁸¹

More gas is used in the summer, partly due to low prices for gas, as well as to meet the growing demand in the electricity sector for air conditioning.

Natural gas used for home heating, managed by LDCs, has high levels of reliability due to regulations and rate recovery, providing a predictable, consistent environment and the ability to recover/payback investments for adding or expanding pipeline capacity and seasonal storage. QER analysis⁸² estimates that the Southeast will need incremental seasonal storage increases as LNG terminals come online. However, storage operators are not seeing much more demand for their services in the near term. In the long term—as demand for natural gas in power generation, exports, and industrial applications increases—storage needs may increase. Production should be able to keep up with this demand, but regional imbalances starting in 2016 could increase demand for storage services in areas like the Southeast, Texas, and—to a lesser extent—in the Northeast.⁸³ Due to growing natural gas production, increased use of gas for electricity-powered air conditioning in the summer, and the current level of seasonal storage capacity, seasonal demand variations and related seasonal price variations have decreased and may decrease further. Additionally, as these price differentials are relied upon to fund storage capacity additions, the investments have slowed in recent years. It is unclear how this trend will impact gas delivery should it continue. Also in recent years, high-deliverability storage capacity investment has slowed despite dramatic increases in utilization (which is discussed in the section on Gas Storage for Meeting Changing Electricity Demands). Other methods of natural gas deliverability, such as additional pipeline capacity and demand response, can improve gas deliverability; however, there is value in studying storage specifically—especially high-deliverability storage—in light of recent market dynamics.

LNG Import and Export Terminals

LNG terminals can either import or export gas; however, conversion of an import terminal into an export terminal comes at a significant expense. An export terminal has equipment to cool and pressurize natural gas until it liquefies. An import terminal has equipment to regasify the LNG, turning the liquid back into its gaseous form. In its 2013 LNG report, EIA estimates that liquefaction plants cost \$1.61 million per million British thermal unit to construct in the United States, whereas regasification plants cost \$0.46 million per million British thermal unit to construct.⁸⁴

In addition to the onshore terminals, the United States has three offshore LNG import terminals in 2011 with a baseload sendout capacity of 1.2 Bcf/d.⁸⁵ These terminals included the Gulf Gateway Energy Bridge in the Gulf of Mexico (which has since been retired due to declining LNG imports into the United States⁸⁶) and the Northeast Gateway and Neptune Deepwater Port located off the coast of Massachusetts.⁸⁷ In offshore import terminal operations, LNG is regasified using shipboard equipment and offloaded into a submerged buoy that transfers the natural gas to a pipeline.⁸⁸

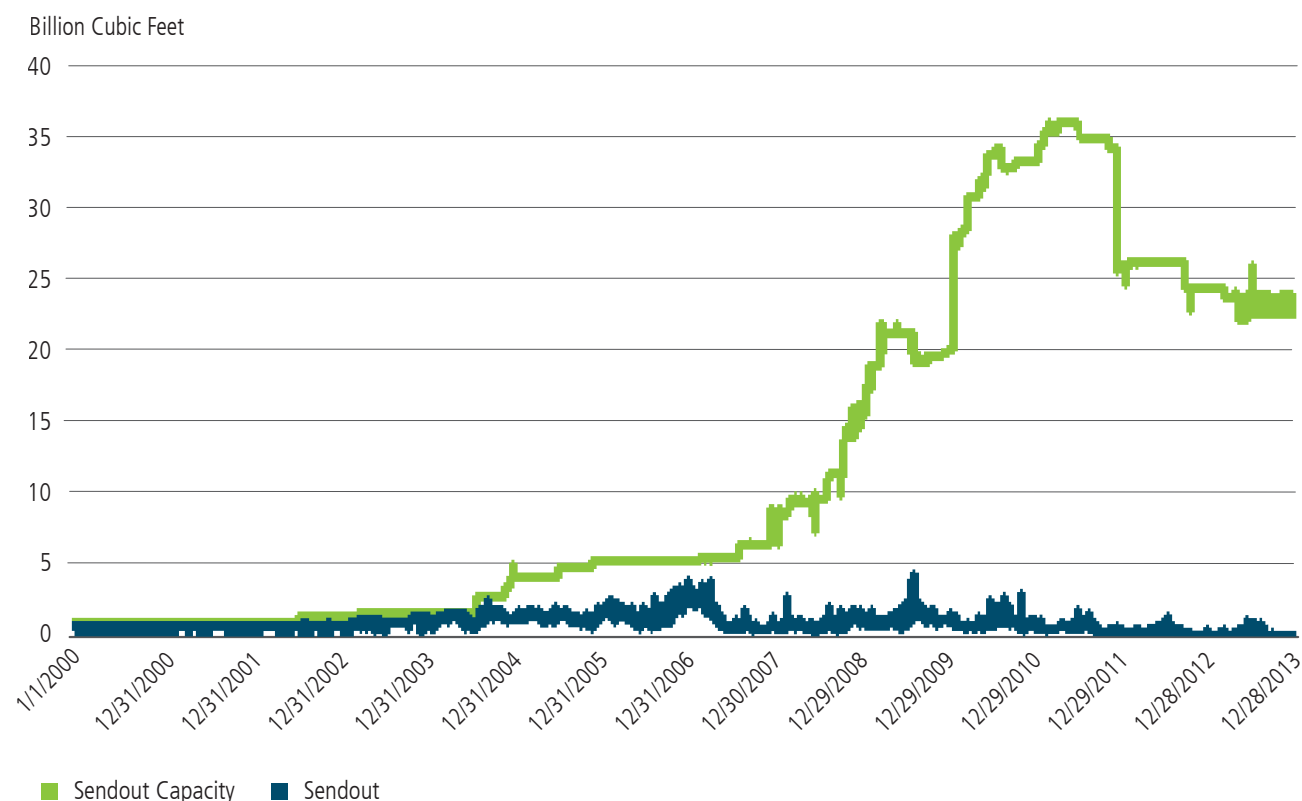
Falling Imports

Net imports of natural gas into the United States have declined since 2007 as a result of the lower price regime and prevailing natural gas prices on the world market, which are considerably higher than prices in the United States.⁸⁹ LNG imports from outside North America have fallen almost to zero in every region of the United States except New England, where prices are relatively high because pipeline transportation in the region is constrained.⁹⁰ Net natural gas imports, including from North America, into the United States as a percent of total natural gas consumption ranged from 15 percent to 16 percent from 2001 to 2007 and fell to 5 percent in 2013.⁹¹

The decrease in the domestic price of natural gas caused a shift in North America gas trade patterns. Ninety-seven percent of U.S. natural gas imports in 2013 arrived via pipeline from Canada. In 2013, total imports from Canada were 2,785 Bcf—a 6-percent decrease from 2012—and they continue to fall.⁹² Meanwhile, exports to Mexico rose to record levels in 2013—rising 6 percent to 658.0 Bcf total (or 1.80 Bcf/d)—and they continue to rise.⁹³ As of September 2014, exports to Mexico are at 2 Bcf/d.⁹⁴

Rising supplies and falling natural gas prices in the United States have opened up a price gap with other parts of the world—especially Asia—eliminated most overseas LNG imports, and left the LNG import capacity in the United States underutilized (see Figure B-15). In response, developers are starting to redesign and repurpose the terminals originally built to import LNG into facilities that allow them to export gas overseas.⁹⁵

Figure B-15. U.S. LNG Sendout and Sendout Capacity from Import Terminals (Bcf), January 1, 2000–July 27, 2014⁹⁶



The sendout of an LNG terminal refers to the amount of gas that is gasified and introduced to the high-pressure gas pipeline system on a daily basis. This figure illustrates that U.S. LNG import facilities are operating under their capacity as domestic prices for gas have decreased and global prices rose.

Export Projections

The increase in U.S. gas production and emerging global demand for natural gas has created a potential opportunity for the United States to export LNG to other parts of the world. Table B-6 shows LNG export terminal projects in different stages of the development process (under construction is the most advanced with all permits and a final investment decision, while not being involved in the FERC process is the least far along). Terminal capacity of 9.22 Bcf/d is under construction, and DOE has conditionally approved an additional 10.00 Bcf/d of terminal capacity. More than five times that amount of capacity has been proposed in applications earlier in the process.

Table B-6. LNG Export Facility Project Status (as of September 2014)

Status	Facilities	Capacity (Bcf/d)
Under construction	Sabine Pass Liquefaction, LLC	9.22
	Freeport LNG Expansion	
	L.P. and FLNG Liquefaction, LLC	
	Cameron LNG, LLC	
	Dominion Cove Point LNG, LP	
	Corpus Christi Liquefaction	
In Federal Energy Regulatory Commission permitting process	16	19.27
In Department of Energy non-Free Trade Agreement permitting process	36	32.36

Currently, 9.22 Bcf/d of LNG export capacity is under construction.

The United States currently has 11 onshore LNG import terminals, most of which have applied to add liquefaction in order to export LNG. In 2013, the United States imported almost 96.00 Bcf of LNG for an average of 0.26 Bcf/d.⁹⁷ The United States has two additional onshore terminals in Kenai, Alaska, and Penuelas, Puerto Rico. The terminal in Kenai is a liquefaction facility that presently exports modest amounts of natural gas from Alaska (primarily for Japan), and the terminal in Penuelas is a regasification terminal that imports LNG for use in Puerto Rico.⁹⁸

The conversion of U.S. LNG import terminals to export terminals is proceeding based on market opportunities for specific facilities. The role of the Federal Government is important to assess the public policy implications, environmental impacts, and public safety of repurposing LNG facilities through current regulatory frameworks.

Renewable Energy and Natural Gas Import Capabilities in the Caribbean

Many Caribbean islands use fuel oil, imported from foreign sources (largely from Venezuela), as a primary fuel for electricity generation. Caribbean islands could benefit from replacing fuel oil with natural gas, other refined products, or renewable sources in their electricity generation mix. On average, the region pays a high price for fuel oil—even with discounts from Venezuela for members of Petrocaribe—spending approximately 11 percent of gross domestic product on oil imports.⁹⁹ Although the Caribbean, as a whole, represents a small market for energy, there is an opportunity for Caribbean nations to reduce electricity costs and emissions from fuel switching to LNG, other refined products such as propane, or renewable generation sources. Even with the cost of facilities needed to import natural gas, countries in the region could save significantly on fuel oil costs by importing U.S. LNG; a feasibility study produced for the Inter-American Development Bank indicated a price differential between fuel oil and U.S. natural gas of approximately \$15 per million Btu in 2014 and a projected differential of approximately \$9 per million Btu in 2020.^{1, 100} Only Puerto Rico and the Dominican Republic import natural gas. Cuba and Trinidad and Tobago produce natural gas for domestic consumption; Trinidad and Tobago also exports natural gas as LNG.

¹ The feasibility study produced for the Inter-American Development Bank used industrial prices from EIA rather than prices for U.S. electricity generators because EIA does not report a price for liquefied petroleum gas for electricity generation.

Fuel switching in the Caribbean for electric power generation would decrease the air emissions of each country and the region as a whole.¹⁰¹ Additionally, displacing Venezuelan fuel oil with U.S. natural gas would have strategic importance for the United States and raise its standing in the region. Natural gas can also provide backup generation for renewable resources that is lower emitting and less expensive than fuel oil.

Currently, there are only two main LNG import terminals in the Caribbean—one in the Dominican Republic and one in Puerto Rico—that have the ability to import natural gas on a large scale through an LNG import terminal. Carib Energy, which received its license to export LNG to non-Free Trade Agreement countries, exports the product in small quantities. The Puerto Rico terminal provides natural gas to a combined-cycle power plant that provides 15 percent of the island's electricity needs. The Dominican Republic terminal, which is owned by the U.S. company AES, provided the power source for about 30 percent of the country's electricity supply. Enabling more countries to import natural gas is critical to building a large enough market to warrant large-scale exports to the region.

Infrastructure and Policy Considerations for U.S. Exports of LNG

Driven by technological breakthroughs in unconventional natural gas production, the United States has seen a surge in the natural gas resource base with relatively low production costs. This has spurred increased gas production and moderated the level and volatility of domestic natural gas prices. Strong global demand for natural gas plus regional liquefied natural gas (LNG) prices linked to oil prices has produced relatively high LNG prices in many regions. The resulting large price differential between U.S. and international gas prices created a strong economic incentive to expand U.S. LNG export capacity and export natural gas from the United States.

The United States' Federal Government has a statutory role in regulating natural gas exports. The Department of Energy (DOE) authorizes natural gas exports based on a public interest determination. The Federal Energy Regulatory Commission reviews the physical aspects of export facilities, including compliance with environmental laws. The Federal Government also has a regulatory role in permitting the siting and rate regulations for interstate midstream infrastructure needed to support LNG exports.

By statute, the Natural Gas Act creates a rebuttable presumption that proposed LNG exports are in the public interest. In the case of countries that have a Free Trade Agreement (FTA) with the United States, the Natural Gas Act requires that applications to authorize the import and export of natural gas be deemed consistent with the public interest and granted without modification or delay.

It is important to understand the current status of approved U.S. LNG export facilities relative to the global LNG market and expectations of future U.S. LNG exports based on global market considerations. As of December 3, 2014, the amount of approved FTA LNG export permits is 40.0 billion cubic feet per day (Bcf/d), with another 1.2 Bcf/d of FTA export capacity pending. Non-FTA export capacity with final approval is 5.7 Bcf/d, with 4.8 Bcf/d conditionally approved. Considering all approved and remaining applications, 38 Bcf/d of non-FTA capacity is pending. For context, total 2013 LNG trade was 31 Bcf/d.^{m, n} Therefore, the 5.7 Bcf/d of non-FTA export capacity from the United States that received final approval is about one-fifth of the near-term LNG market. The total proposed non-FTA capacity of about 38 Bcf/d would be more than the total 2013 world LNG market. DOE approvals for U.S. LNG exports are within the range of future export requirements, and additional reviews for DOE export approval are in process.

Major studies that have estimated U.S. LNG export volumes as an endogenous variable determined by global pricing and supply/demand fundamentals include the National Economic Research Associates (NERA) study of 2012^o and an update by

^m Using a conversion factor of 1 metric ton = 48 Bcf.

ⁿ BP. "Statistical Review of World Energy." June 2014. <http://www.bp.com/en/global/corporate/about-bp/energy-economics/statistical-review-of-world-energy/statistical-review-downloads.html>.

^o Montgomery et al. "Macroeconomic Impacts of LNG Exports from the United States." NERA Economics. 2012.

Infrastructure and Policy Considerations for U.S. Exports of LNG (continued)

NERA in 2014,^p as well as an analysis by the Baker Institute of Public Policy (Baker).^q In addition, DOE commissioned a study by Jensen Associates^r (Jensen) that analyzed alternative supply scenarios with demand calibrated to external forecasts.

The NERA 2012 study examined a range of scenarios based on different combinations of assumptions about international supply and demand, availability of domestic natural gas, and LNG export capabilities. NERA's analysis of the Energy Information Administration's 2012 Annual Energy Outlook Reference case found that there would be no U.S. exports. The NERA 2014 update followed the same basic methodology with updated EIA projections of a significantly higher level of U.S. natural gas production. Consistent with high U.S. natural gas production, the analysis suggests that there will be LNG exports. In 2028, NERA estimates, 4.5 Bcf/d of U.S. LNG exports with reference scenarios. Another analysis of future U.S. LNG exports using an endogenous estimation of volumes was conducted by Baker. Drawing on the integrated modeling framework and comprehensive analysis, the study concludes, "LNG exports from the United States approach 6 Bcf/d by 2020, making it the third-largest LNG exporter in the world."

The presence of oil linked contracts and marketing strategies by nationally owned LNG suppliers introduces two important elements into market projections that may be difficult to quantify with an equilibrium modeling approach. In order to add robustness to assessments of future LNG dynamics, DOE commissioned a study by Jensen to analyze current and future global LNG dynamics. Jensen analyzed the LNG market using a supply scenario approach. The Jensen analysis concludes that the global LNG market is likely to be oversupplied in the near future, suggesting a distinct market limit on U.S. LNG exports. In the reference case, Jensen projects 9 Bcf/d of exports in 2030. The highest and lowest scenarios for LNG exports generate 12 Bcf/d and 9 Bcf/d, respectively. Future volumes of LNG exports will be determined by the interaction of global supply and demand.

In summary, rigorous analysis that includes global supply and demand dynamics results in estimates for the volume of long-term U.S. LNG exports falling between 5 Bcf/d and 15 Bcf/d. To test the infrastructure implications of the upper range of potential of U.S. LNG exports, DOE commissioned a study by Deloitte^s to analyze a stress test where it was assumed that 20 Bcf/d of U.S. LNG export capacity was available. Even in this very high LNG export case, U.S. domestic infrastructure additions are within historical norms, excluding LNG export terminals.

Analysis conducted by DOE's Office of Energy Policy and Systems Analysis indicates that a high case of U.S. LNG export volumes are likely to be adequately served by the pipeline and marine terminal infrastructure at existing import terminals (supplemented with planned capital upgrades). The Continental United States has a vast, mature, and robust natural gas infrastructure. Infrastructure development generally responds well to market signals. For the liquefaction facilities, new terminals are very likely to be brown-field projects looking to outfit existing import terminals with liquefaction equipment where much of the infrastructure—including pipelines, storage tanks, loading berths, and marine loading arms—is already in place. These are dedicated terminals that may not add to individual port congestion, but increased traffic may be an issue on already busy waterways (see Chapter V, Improving Shared Transport Infrastructures).

Some infrastructure development may be required to support U.S. LNG exports, but this is not expected to go beyond historic norms, and the existing industry framework is adequate to support infrastructure development. The role of the Federal Government is important to assess the public policy implications, environmental impacts, and public safety of U.S. LNG exports.

^p Montgomery et al. "Updated Macroeconomic Impacts of LNG Exports from the United States." NERA Economics. 2014.

^q Medlock, K. "The Land Of Opportunity? Policy, Constraints, and Energy Security in North America." Baker Institute of Public Policy. 2014.

^r Quadrennial Energy Review Analysis: Jensen, J. "LNG Analysis Summary: A Different Way of Looking at the Future of World LNG Trade." Jensen Associates. 2014. <http://energy.gov/epsa/qer-document-library>.

^s Quadrennial Energy Review Analysis: RAND Corporation. "Scenario Development for the 2015 Quadrennial Energy Review." 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).

Natural Gas Pipelines

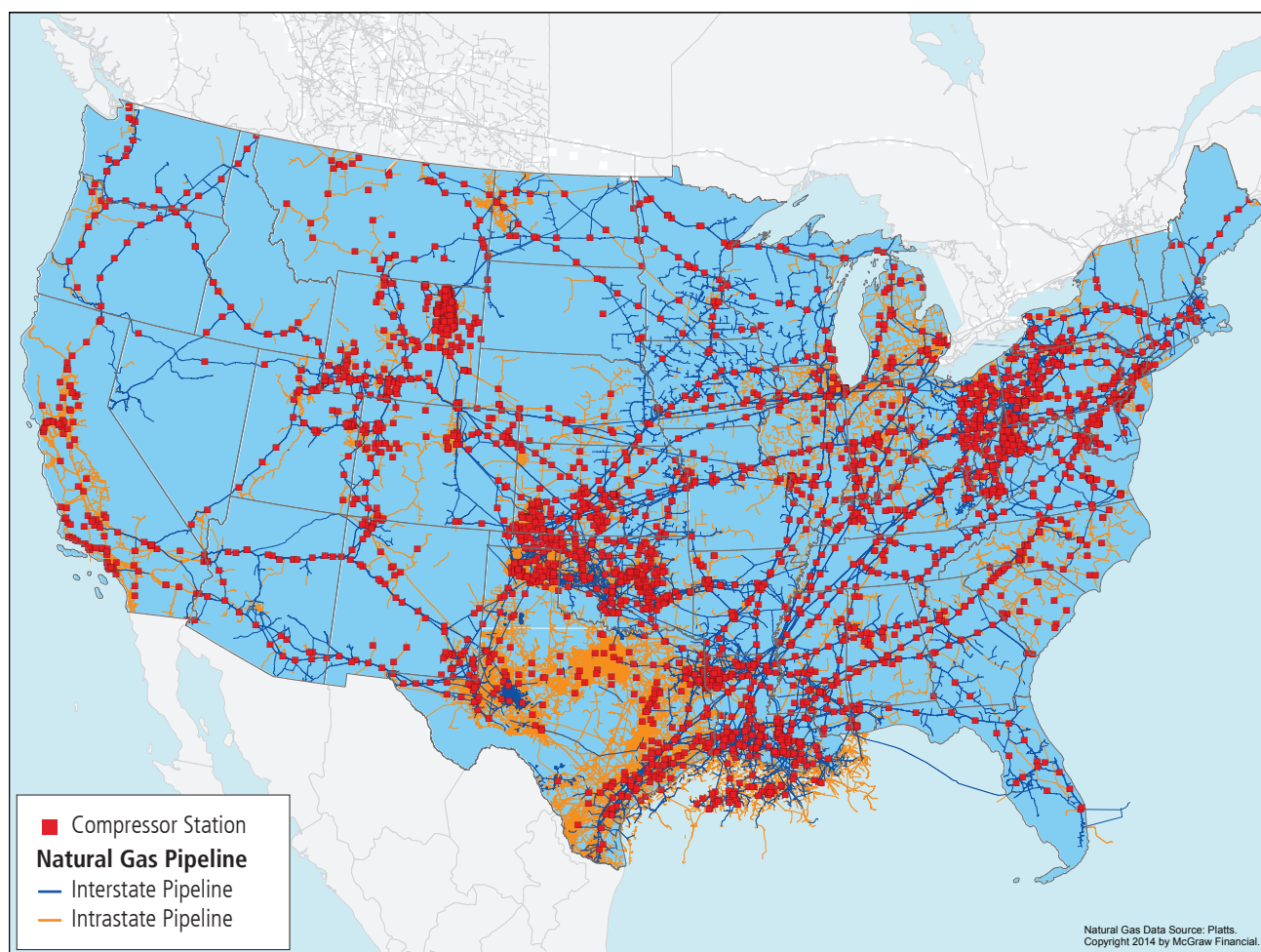
The U.S. natural gas pipeline network is designed to transport natural gas to and from most locations in the lower 48 states. The transmission pipelines are configured to transfer natural gas from production and storage areas to distribution systems and some large end users. They are designed to be capable of meeting peak demand of shippers with contracts for firm service.¹⁰²

As of 2007, there were 210 pipeline systems with 305,000 miles of high-pressure transmission and gathering pipelines operating in the United States.^{103, 104} From 2008 through 2013, approximately 4,000 miles of interstate transmission pipelines were constructed.¹⁰⁵ In 2007, two-thirds of the lower 48 states were almost entirely dependent on the interstate pipeline system for their supply of natural gas.¹⁰⁶ The pipeline system is supported by more than 1,400 compressor stations that maintain pressure in the pipelines and assure that natural gas is continuously flowing (see Figure B-16).¹⁰⁷

Many pipeline systems are configured for the long-distance transmission of natural gas from production regions to market areas through trunk lines. As the volume of natural gas that a pipeline can carry is determined by the diameter of the pipe and operating pressure, trunk lines are built with large diameter pipe (20 inches to 42 inches) to maximize potential capacity.¹⁰⁸

The maximum operating pressure a pipeline can achieve is dependent on several factors, including the number of compressor stations the pipeline operator has deployed.¹⁰⁹ Compressor stations contain compressors driven by electricity, internal combustion engines, or turbines that create pressure to push gas through pipelines.¹¹⁰ Compressor stations are located about every 50 miles to 100 miles along pipelines to boost the pressure in pipelines and move the gas downstream (see Figure B-16).¹¹¹ Most compressors are powered by natural gas; however, about 5 percent of total installed compressor horsepower on interstate pipelines is from electricity, which is used to reduce emissions from compressor stations.¹¹² Methane emissions from compressor stations account for the majority of leaked and vented methane from transmission and storage in natural gas systems¹¹³ (more discussion follows).

Figure B-16. Natural Gas System Mainline Compressor Stations, 2008¹¹⁴



Compressor stations are present throughout the natural gas system.

Pipeline companies often can add capacity to existing lines by adding compressor stations, by increasing the power of existing compressor stations, or by looping. Looping involves building a parallel pipe along a pipe segment, which increases the volume that can be transmitted. Both looping and additional compression can be done within the right of way of the original pipe, which reduces incremental environmental impacts and the time needed to increase capacity. Another way to increase capacity factors with the existing infrastructure is to reverse traditional flows. For example, the Rockies Express (REX) pipeline, which has transported natural gas from Wyoming to the Northeast, is now being reversed so that it can move natural gas from the Northeast to the Midwest.¹¹⁵

Pipelines are designated as interstate or intrastate. Interstate pipelines are major trunk lines that transmit gas between states. In 2008, the interstate portion of the national natural gas pipeline network made up 71 percent (about 215,000 miles) of all natural gas mainline transmission mileage.¹¹⁶ Intrastate pipelines make up the other 29 percent (about 90,000 miles) of national natural gas mainline transmission mileage. They operate within state borders and link producers to local markets and the interstate pipeline network.¹¹⁷

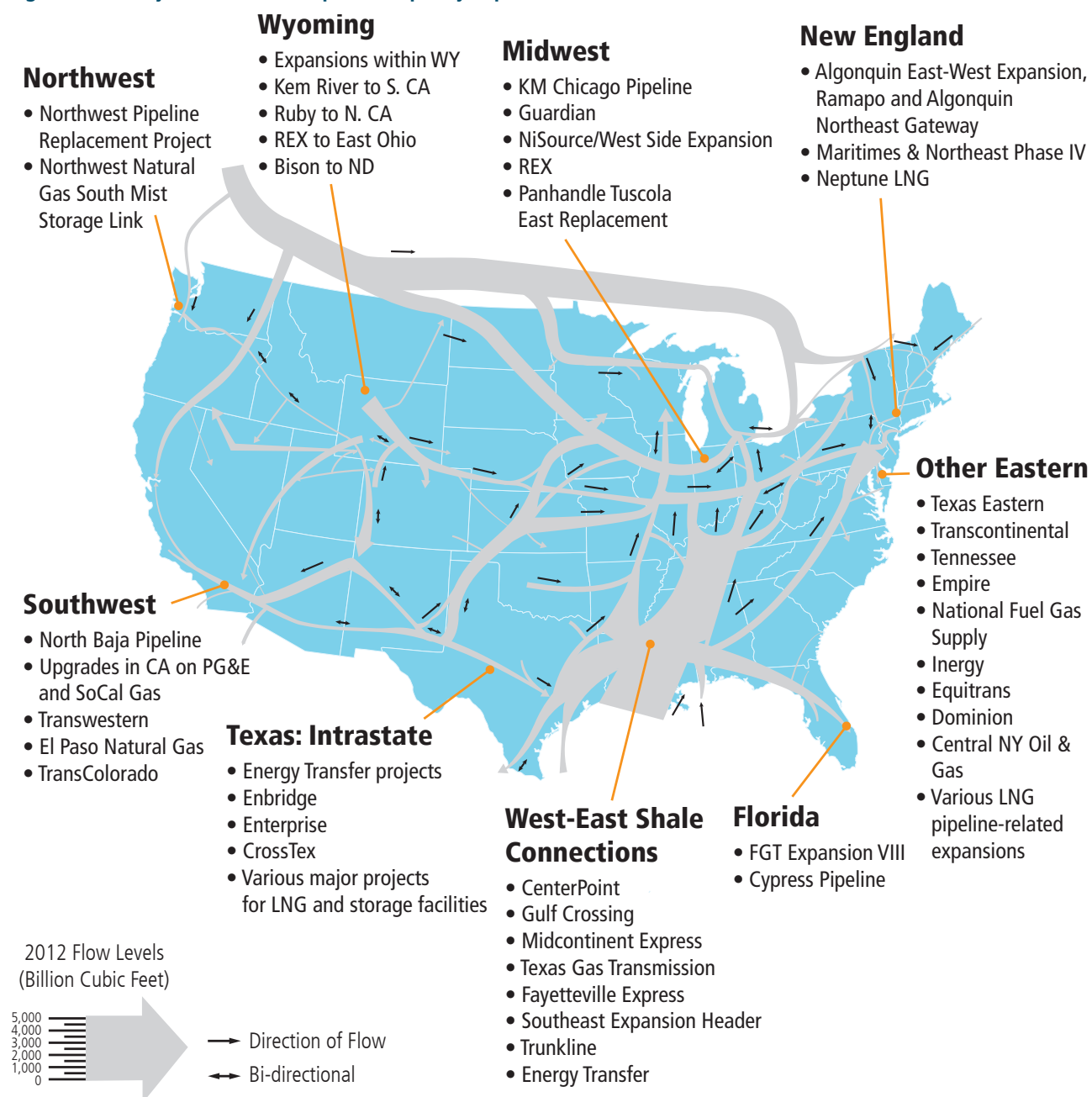
Pipelines are often connected at hubs, which operate as both physical transfer points and market centers. Hubs increase the physical flexibility of gas flow by allowing operators to switch gas along different pipelines as needed. Hubs also enable the quick and easy trading of gas between a wide range of buyers and sellers, allowing for an effective and efficient natural gas market.¹¹⁸ There are about 20 major hubs in the United States, but Henry Hub in Louisiana serves as the main national hub due to its location in the Gulf Coast producing

area and level of interconnectedness with pipeline systems. In 2012, the Henry Hub had 4 major receipt points and 12 delivery points.¹¹⁹ Henry Hub has also become the national benchmark for natural gas pricing. With developments in the Northeast, Henry Hub may lose its position as primary price point by 2030.

Increased Capacity of High-Pressure Transmission Pipelines

For many years, western U.S. supplies of natural gas were less expensive than those in the East, based in Louisiana and the Gulf of Mexico. Growing production in shale basins on the western side of the price divide further increased the value of new pipeline capacity to link the regions and spurred new construction of pipelines (see Figure B-17).

Figure B-17. Major Natural Gas Pipeline Capacity Expansions, 2004–2014¹²⁰



Pipeline expansion allows increased unconventional natural gas production to reach demand centers.

EIA estimates that between 2004 and 2013, the natural gas industry spent about \$56 billion expanding the natural gas pipeline network. Between 2008 and 2013, pipeline capacity additions totaled more than 110 Bcf/d.¹²¹ Approximately 10 percent of this investment was dedicated to completing the 1,768-mile REX pipeline, linking production fields in Wyoming to markets as far east as Ohio.¹²² A substantial portion of the rest of the investment was used to link the Barnett, Haynesville, and Eagle Ford Basins in Texas and the Fayetteville Basin in Arkansas to markets in the East. As of June 2014, 1,862 natural gas wells were drilled but not producing in the Marcellus region, suggesting wells drilled to meet lease and permit requirements or insufficient infrastructure to get increased production to market.¹²³

Factors Influencing the Need for New Pipelines

Despite the significant increase in domestic gas production, the widespread geography of domestic gas demand combined with significant flexibility and capacity in the existing transmission system mitigates the level of pipeline expansion and investment required. In many recent cases, new gas production is located near existing or emerging sources of demand, which will reduce the need for additional natural gas pipeline infrastructure. In instances where new natural gas pipelines are needed, investments are often enhancing existing network capacity. Midstream infrastructure in the Marcellus is the exception to this trend, but in this case large investments in pipelines and processing plants is evident, both in recent historic investment data and in modeled projections.¹²⁴

Midstream market participants expand the pipeline network by pursuing the lowest-cost options to move product to market. The level of additional pipeline infrastructure required is an outcome of the following process:

- In cases where new production must travel via interstate pipelines to reach demand centers, the most inexpensive way to transport it is by using available existing infrastructure. The United States benefits from an extensive pre-existing gas network for several reasons: (1) pipelines are long-lived assets that reflect historic supply and demand trends; (2) pipelines often are sized to meet a high initial production level and have available capacity in the long term due to expiring firm shipping contracts and changes in shippers' supply sources; and (3) some pipelines were built specifically to provide gas to residential and commercial consumers in cold weather regions (such as pipelines built to meet winter heating demand in Minnesota), but not for power generation. These pipelines often are not fully utilized during off-peak seasons.
- In cases where utilization of the existing pipeline network is high, the next most cost-effective solution is to add capacity, via compression, to existing lines. While this is a form of infrastructure investment, it is more economical, faster, and simpler for market participants in comparison to building a new pipeline. Modern pipelines usually are built so that compression can be added later, increasing capacity at relatively low cost. Developers recognize that the most significant challenge is developing new pipelines, so they design them in such a way that they are able to handle additional capacity if needed. The Pipeline and Hazardous Materials Safety Administration (PHMSA) currently regulates pipeline capacity safety via the Maximum Allowable Operating Pressure standard. As persons and businesses move near pipes, the Maximum Allowable Operating Pressure may be reduced. This regulatory mechanism balances cost-effective utilization of existing infrastructure with public safety concerns.¹²⁵
- If existing pipeline utilization is high and capacity is maximized, then the price differential between the two points on the network should increase and create an incentive for shippers to support midstream pipeline development in order to capture the arbitrage opportunity across the network. The need for new pipelines is apparent in the Marcellus, where the largest amount of pipeline investment is expected to occur.¹²⁶ This is primarily because the existing network has never had the scale of gas production that is coming online in that region.

- EPSA analysis of FERC data on market constraints described later in this appendix indicates that since 2006, when price differentials between regions became significant, new pipelines were built and price differentials subsided. In the past few years, supplier constraints have appeared in the Marcellus, but analysis of historical data, combined with Deloitte projections, suggests that the market signals have facilitated near-term infrastructure build-out in that region and reduced existing constraints.¹²⁷
- In some regions, it may be challenging to build new lines due to social concerns, local political considerations, or other behavioral economic factors. However, despite these factors, regional price spikes (such as those witnessed in New England last winter) create powerful incentives for state and local officials to take action to address network constraints.

Narrowing of Price Differentials across Regions

Growing natural gas production and infrastructure additions have changed the pattern of natural gas pricing in the United States (see Figure B-18).

From 2005 to 2008, natural gas prices differed considerably from region to region:

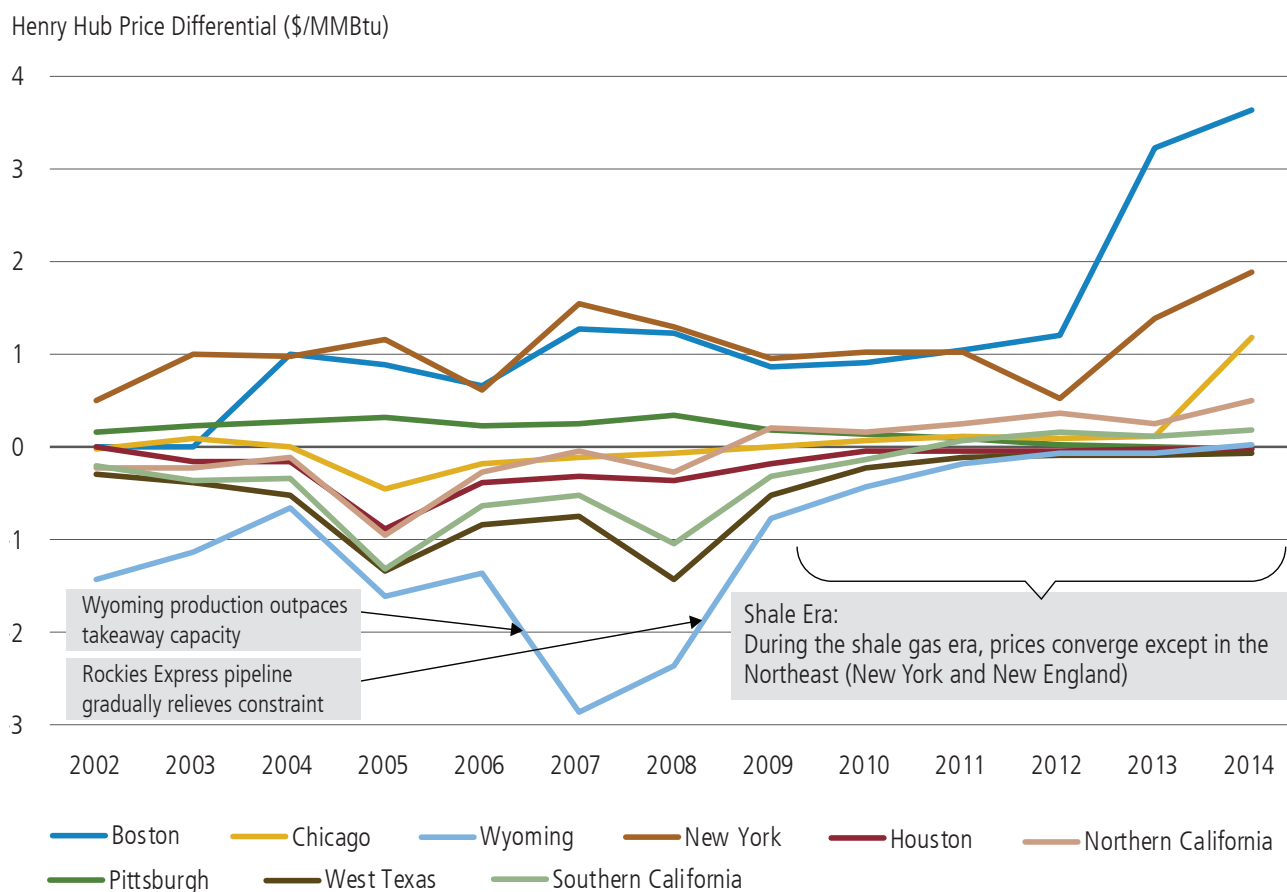
- Wyoming was fully integrated into continent-wide markets when the REX opened its leg into the Midwest in 2008. Prices in Wyoming (Opal Hub) were less than spot prices at Henry Hub—they had a negative basis differential, or location advantage, to Henry Hub. This negative basis varied over time and occurred because pipeline additions could not keep up with rapidly increasing production in the region. This basis differential disappeared when the Midwest leg of the REX pipeline opened in 2008.
- Prices in New York City and New England (Algonquin Citygate Hub) were greater than spot prices at Henry Hub—they had a positive basis to Henry Hub. This positive basis was a result of pipeline constraints in the region. The New England region is located at the end of major pipeline routes from traditional producing areas and tended to be constrained during peak periods, allowing prices to rise much higher in this region than the rest of the country.
- Prices in the rest of the country showed a moderate level of dispersion, but they did not see the deviations from Henry Hub seen in New England and Wyoming. Prices tended to rise as one moved farther away from major producing regions. Prices in the Mid-Atlantic and California tended to be higher, while those in Texas and Oklahoma tended to be lower.

Since 2008, average annual prices for most of the country have converged, with the exception of the Northeast region:

- Pipeline construction linking shale basins in Texas and Arkansas to markets in the East relieved constraints on transmission of natural gas from West to East. Most markets in the East also are now near major new production areas. Shale production has grown rapidly in the Marcellus in Pennsylvania. Production growth in this area and the lack of progress to date on pipelines to New England mean prices in Pennsylvania are now often lower than those in Louisiana and Texas.¹²⁸
- Pipeline constraints remain severe into New England and have not changed with the increasing growth of production from the Marcellus. During peak periods, natural gas prices in those areas can rise to very high levels.¹²⁹ Prices rose as high as \$34.38 per million Btu during cold snaps in the winter of 2012-2013 and increased to \$78.64 per million Btu during the southward shifts in the polar vortex in the winter of 2013-2014.¹³⁰
- Spot prices for the Northeast reflect only small volumes of natural gas traded at these prices, but can lead to dramatic increases in the price of electric power in the region. Prices had little direct effect on natural gas customers, as most customers are served by distributors who moved gas from outside the region under long-term contracts. However, high prices can lead to dramatic increases in the electric power prices because the price of power often reflects local spot gas prices.¹³¹

- During off-peak periods, pipelines into New York City and New England were often not constrained. In 2014, off-peak prices in those regions typically reflected the price of Marcellus production, and they actually were somewhat lower than the national benchmark at Henry Hub. The constraints relate to special construction challenges in the densely populated New York City and New England areas. In New England, other challenges with the electricity market contribute to the lack of additional pipeline capacity (more discussion follows).
- In 2014, new capacity into New York City eliminated the price premium to Henry Hub. In December 2014, wholesale gas prices were lower in Manhattan than in Baton Rouge, Louisiana.¹³²

Figure B-18. Natural Gas Price Differentials (\$/million Btu) between Henry Hub and Key Trading Points Narrow during the Shale Revolution, except in New England¹³³



The difference in natural gas prices between Henry Hub and key trading points reflect regional gas infrastructure constraints and the price signal that spurs infrastructure investment. In the Northeast, recent pipeline projects have primarily focused on transporting gas to the New York, New Jersey, and Mid-Atlantic regions but have had limited benefit for consumers in New England. Flow day prices are from Intercontinental Exchange and differencing regional prices are from Henry Hub.

Natural Gas Pipeline Capacity

Pipelines can act as a market constraint when their capacity limits the supply that can be delivered to a specific region. The magnitude of that constraint is quantified by the price differentials between hubs in the natural gas network.

Analysis of basis differentials across the natural gas system provides a metric for assessing infrastructure constraints. The basis differential analysis provides useful indicators of the level of constraints on the natural gas pipeline network and how this has changed over time, but it does not calculate a market value. Spot market data indicate the value of pipeline constraints since 2006 and suggest the following:

- Constraints have been consistently low since 2006, with the spike during the early 2014 “polar vortex” being an exception.
- The constraints that limited producer access to markets were highly valued through 2008, when new pipelines opened from Wyoming to the Midwest and from Western producers to Eastern markets. They have largely disappeared since then; although, northeast Pennsylvania is now seeing a similar constraint on bringing natural gas production to wider markets.
- For natural gas customers, pipeline constraints can be both seasonal and regional, occurring primarily during the winter. From 2006 through 2009, they affected New England and the West (largely California) in roughly equal measure. However, since that time, the Northeast has seen most of the constraint value increase with fewer constraints in the West.
- As low-cost gas from the Marcellus reaches markets in the Midwest via expanded midstream infrastructure, it becomes more difficult for higher-cost gas from the Rocky Mountain region to maintain market share in the Midwest. For this reason, additional pipelines may be needed for Rocky Mountain gas to reach other markets in the West, such as California.¹³⁴
- The effect of the southward shift of the polar vortex in the first quarter of 2014 was more acute and widespread than constraints in earlier years. The value was much higher in aggregate, and many points in the Midwest were affected along with those in New England. The deep cold of the polar vortex not only increased demand for heating fuel, it also caused freeze-off of wells (see the Natural Gas TS&D System Reliability and Resilience box for definition) and related equipment that reduced production.¹³⁵

In sum, in the middle of the last decade, natural gas pipeline constraints affected both producers and customers. Over the years, constraints affecting producers fell rapidly and remained low. Suppliers from all over the country could gain roughly similar prices for their products most of the time. Customer constraints in New England, however, remained in place and varied mostly according to the severity of the winter. In 2014, the southward shift of the polar vortex greatly stressed the natural gas systems and led to the highest overall constraint values since 2006 (see Table B-7).

Several Independent System Operators (ISOs), state governments, and FERC are actively seeking ways to increase gas and electric system reliability in New England. The actions undertaken by the ISOs, Regional Transmission Organizations (RTOs), and market participants—such as PJM’s Cold Weather Preparation Guidelines and the continuation of ISO New England’s Winter Reliability Program for a second winter—have improved operational performance and moderated prices.¹³⁶ During the winter of 2014-2015, prices moved dramatically lower, peaking at just less than \$30 per million Btu in February 2015.¹³⁷ A number of factors contributed to the lower and less volatile prices observed in the 2014-2015 winter, including increased natural gas production, abundant storage inventories, increased pipeline capacity, and better gas-electric coordination, as well as ISO and RTO programs that improved operational performance and the availability of gas-fired electric generating units.¹³⁸

Table B-7. Spot Market Value of Natural Gas Pipeline Constraints, 2006–2014^{139, t, u}

Year	Spot Market Value		Total (\$Billion)
	Supplier Constraint Value (Price less than Henry Hub)	Customer Constraint Value (Price more than Henry Hub)	
2006	2.14	1.55	3.69
2007	3.39	1.96	5.55
2008	2.65	1.38	4.03
2009	0.90	0.84	1.74
2010	0.56	0.83	1.39
2011	0.39	0.85	1.24
2012	0.23	0.72	0.95
2013	0.32	0.89	1.21
2014 (through July)	0.52	2.31	2.83

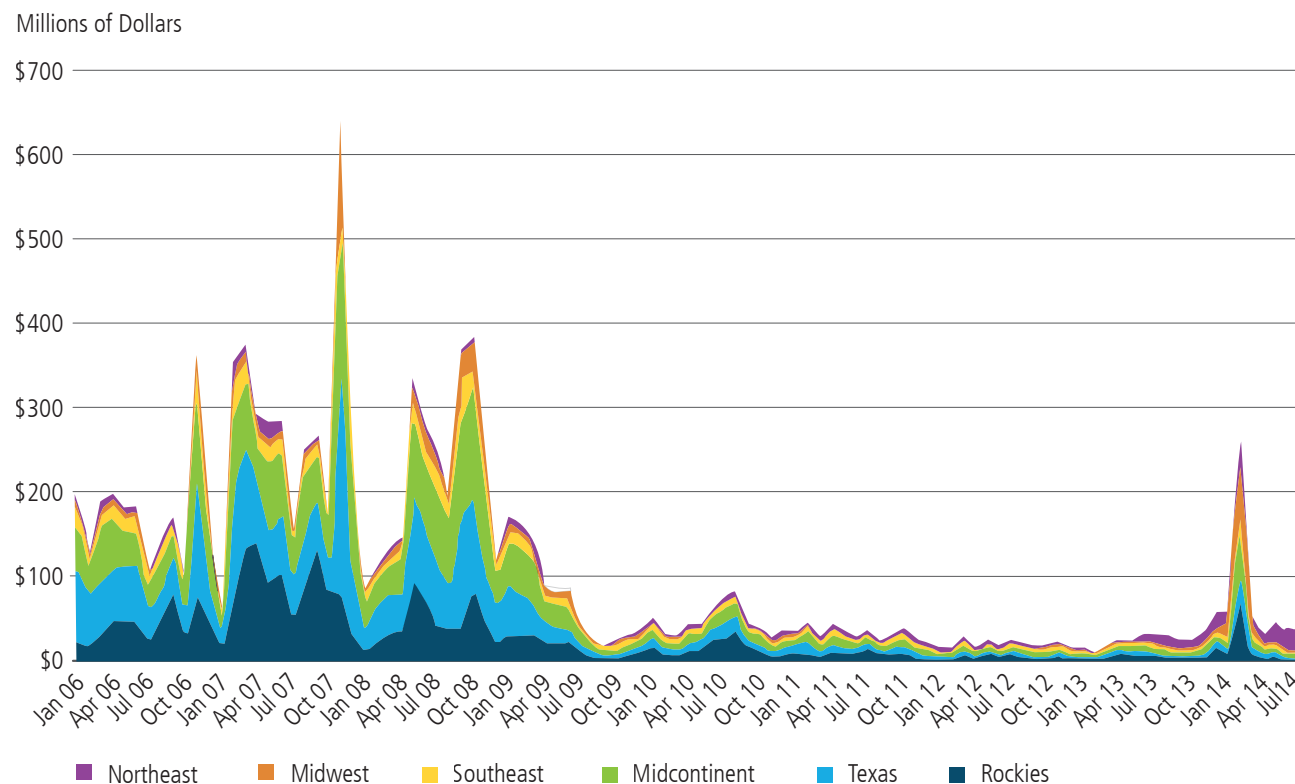
Each year, natural gas pipeline constraints resulted in total gas charges that were between \$0.95 billion and \$5.55 billion above what they would have been had the gas been traded at the Henry Hub price.

Supplier Constraints

The majority of the value of supplier constraints is in two areas: the Rockies and the Continental Divide. Supplier constraints largely disappeared after 2008, even as production volumes rose rapidly. Newly constructed pipelines relieved both of the main constraint areas. Only in recent years has a new supplier constraint appeared—northeast Pennsylvania. Starting in 2013, producers began having difficulty getting Marcellus gas out of northeastern Pennsylvania, and the local price fell, often to levels well below those of Henry Hub. These constraints did not affect other Marcellus gas farther south and west in Pennsylvania (see Figure B-19).

^t Measures of the value of monthly and regional congestion on the U.S. gas pipeline grid were developed by analysis of daily price and trade data at all price points listed on the Intercontinental Exchange: (1) Daily basis to Henry Hub for each Intercontinental Exchange price point were calculated by subtracting Henry Hub from the daily cash price. (2) Each Intercontinental Exchange price point was designated as either a production price point or a consumption price point depending whether daily basis to Henry Hub at each Intercontinental Exchange price point was positive or negative, averaged between January 2011 and July 2014. Intercontinental Exchange price points with negative basis were designated as a production price point, and Intercontinental Exchange price points with a positive basis were designated as a consumption price point. (3) The daily value of congestion at each price point was calculated by multiplying the absolute value of basis by the traded volumes on Intercontinental Exchange. (4) Each price point was assigned a region—Northeast, Southeast, Midwest, Midcontinent, Texas, the Rockies, and the West. Monthly regional production congestion was calculated by summing daily congestion at each price point by month and region. Monthly regional consumption congestion was calculated in a similar manner.

^u Prices are in nominal dollars.

Figure B-19. Estimated Supplier Market Constraint Value by Region, 2006–2014¹⁴⁰

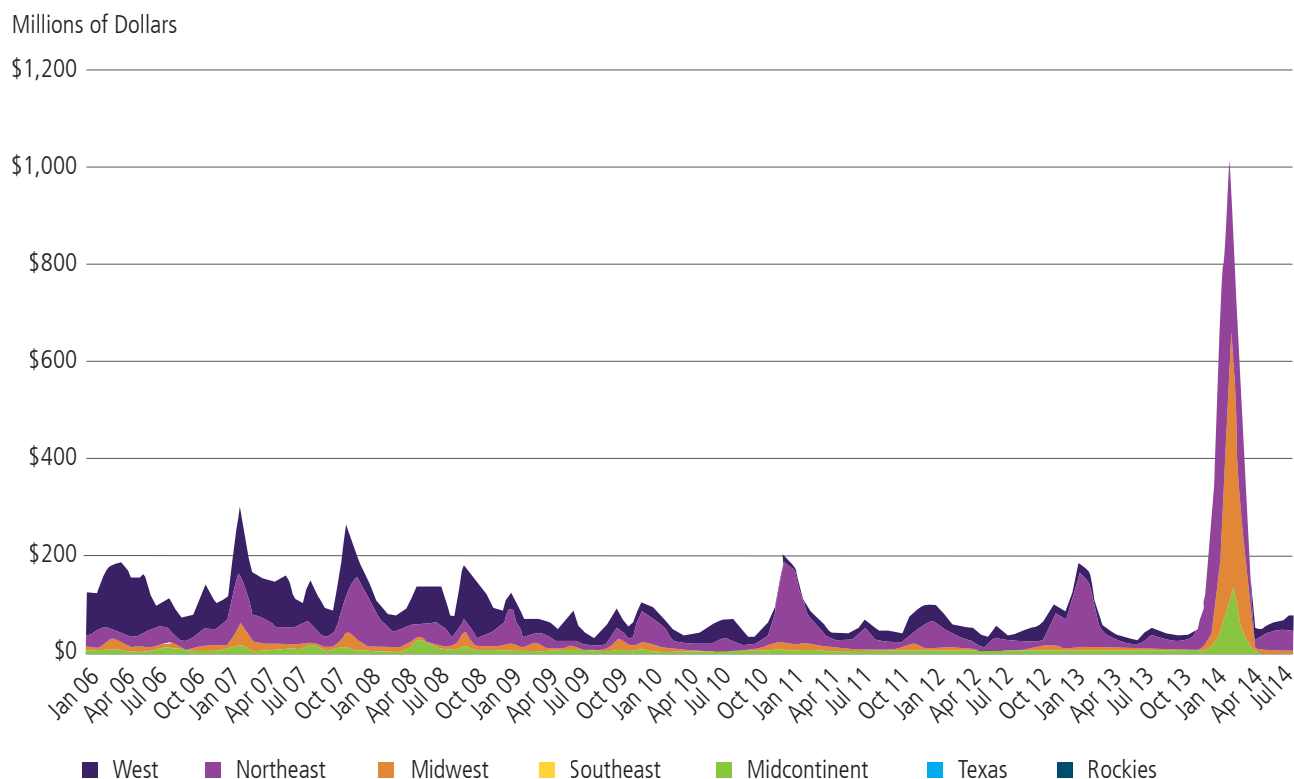
Overall supplier market constraints have fallen significantly since supplier market constraints in the Rocky Mountain region were reduced in 2008–2009.

Customer Constraints

The most obvious feature of customer constraints is the high values associated with the southward shifts of the polar vortex in the winter of 2013–2014. Otherwise, customer constraint values have fallen in the West but remained in place in the Northeast (including New England, New York, and Pennsylvania). In 2006, both the Northeast and the West (largely California) paid a significant premium over Henry Hub in the winter. Since then, the Western premium has largely disappeared, partly because of greater access to Wyoming supplies. However, the Northeast premium remained, with the magnitude depending on winter weather. For example, it was lower in 2012 in response to an unusually mild winter, but it rose again in 2013 with more normal weather—even before the extremely cold southward shift in the winter of 2013–2014.

The southward shift of Arctic air in the winter of 2013–2014 formed a truly extraordinary period. Not only were the Northeast constraints severe, but the value of constraints into the Midwest also rose to high levels. Additionally, the overall value was far higher than in previous years. Even with a solution to the long-standing Northeast issues, the polar vortex probably would have stressed the national pipeline network.

Figure B-20. Estimated Customer Market Constraint Value by Region, 2006–2014¹⁴¹



Total customer market constraints generally have been \$0–\$200 million since 2006, but spiked in the Northeast and Midwest in earlier 2014.

Constraints in the past were felt by suppliers, as seen by the high constraint market values in 2006–2007 (see Figure B-20). As a result, the supplier market acted to correct constraints where they existed.

Despite the significant increase in production, the nature of expected supply and demand increases and the flexibility and optionality embedded in the existing natural gas system mitigate the level of expansion and investment required. Several factors influence pipeline utilization:

- Pipelines are often sized to meet a high initial production level, but due to declines in well production over time, are left underutilized in the long term.
- Typically, pipelines are designed to meet the contractual requirements of the shippers; compression can be added later if needed to meet increased demand, increasing capacity at relatively low cost. Pipelines are long-lived assets that reflect historic supply and demand trends. Yet, these assets remain available for future needs and provide flexibility because they require less capital investment than building new pipelines.
- Some pipelines were built specifically to meet the peak seasonal heating demands of residential and commercial consumers in cold weather regions (such as Minnesota, which uses more coal than natural gas for power generation).

Emerging increases in natural gas production are co-located with some of the most significant demand drivers, such as increased demand for power generation in Ohio and Pennsylvania and LNG export terminals on the U.S. Gulf Coast. This, combined with latent system capacity, reduces anticipated natural gas pipeline investment below what might otherwise be expected.

The impact of natural gas demand on midstream infrastructure can be seasonal and highly localized, so prices may rise in response to system constraints in one season and fall in the next. This is primarily a challenge in New England. For example, expansion projects¹⁴² to bring capacity to New York/New Jersey and Mid-Atlantic markets were expected to bring more than 2.0 Bcf/d of expansions for 2013–2014.¹⁴³ Later that winter, after the price spiked to \$117 per million Btu at a regional hub in New York due to the polar vortex, it later fell to \$1–\$2 below Henry Hub in the summer of 2014 because there was an oversupply of gas in the region.¹⁴⁴ In the mid to long term, incremental outbound capacity from Pennsylvania and Ohio is expected to exceed Marcellus production (i.e., pipeline constraints in Marcellus are a short-term phenomenon), assuming expected pipeline expansions go in service on time.¹⁴⁵

Investment is still needed in the Northeast to connect up the large new supplies and to add capacity to crucial links, but it is much smaller than the investment that would be needed to deliver gas to market from a distant supply source. Nonetheless, these investments face challenges determining feasible rights of way and developing community support for the projects. Similarly, a major change in the sources of demand for gas will be the growth of LNG exports from the Gulf Coast. Export terminals are located in an area that has long had extensive natural gas infrastructure in place, which mitigates the amount of additional infrastructure required.

Changes in TS&D infrastructure are required to sustain U.S. energy supply growth and the economic and security benefits it provides. However, despite the significant increase in production and the infrastructure challenges this poses, the regionality of expected supply and demand increases and the flexibility and optionality embedded in the existing natural gas infrastructure system mitigate the level of expansion and investment required. In particular, the new production patterns will impact infrastructure in the following ways:

- The significant growth of production outside the Gulf Coast region—especially in Pennsylvania and Ohio (see Figure B-2)—is causing re-orientation of the transmission pipeline network. The most significant of these changes will require reversing flows on pipelines to flow Marcellus and Utica gas to the southeastern Atlantic region and the Midwest (lowering demand for Canadian imports to the Midwest). However, the necessary pipeline investments would be much greater if these new supplies were not located near large population centers that were already reliant on natural gas from the Gulf Coast. Growing supply by the Marcellus and Utica Basins will require more internal capacity within Pennsylvania and West Virginia and increased capacity to move gas to demand centers in the Midwest and Southeast.
- Because a significant portion of LNG exports are expected to originate from the U.S. Gulf Coast, exports of LNG are forecasted to reduce movement of gas from the Southeast to other U.S. regions. It may also place upward pressure on gas prices that would reduce demand growth for gas-fired electric power and new industrial load within the Southeast.
- Increased use of gas-fired generation and growing exports to Mexico will require strengthening the natural gas pipeline network in the Southwest.
- The existing natural gas pipeline network possesses latent capacity, reducing the need to build new pipelines. This is the case even in high natural gas demand projections that indicate only moderate incremental new pipeline infrastructure would be needed.¹⁴⁶

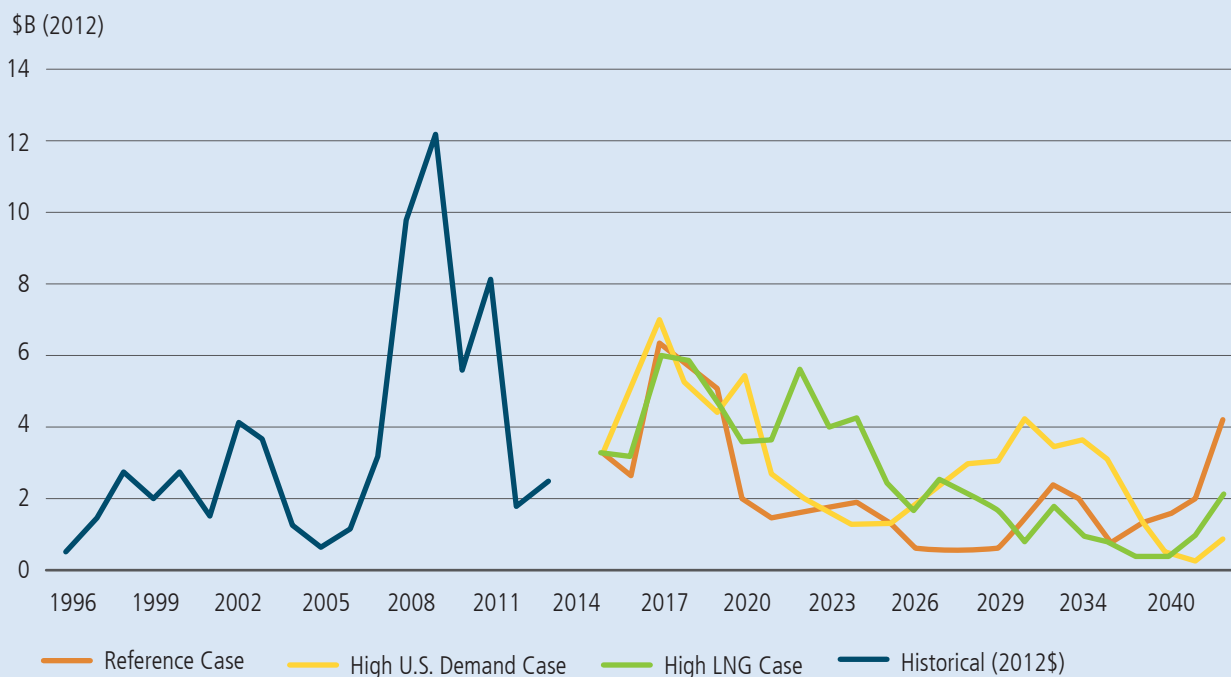
Projected Pipeline Investments through 2030

QER analysis utilized industry data, EIA historical data, and projections to assess potential needs for additional pipeline capacity through 2030. The 2030 outlook also incorporates projections prepared for DOE by BENTEK¹⁴⁷ and Deloitte,¹⁴⁸ as well as analysis conducted for the American Petroleum Institute by IHS¹⁴⁹ and for the Interstate Natural Gas Association by ICF.¹⁵⁰ In addition, the American Gas Association provided insight into the costs associated with upgrades to the natural gas distribution network. These projections relied on differing assumptions and methodologies, but—in combination—they provide a detailed perspective on gas infrastructure needs.

Regional Trends in Pipeline Investment: Natural Gas Infrastructure Implications of Increased Demand

The Department of Energy commissioned Deloitte MarketPoint analysis to understand the sensitivity of the interstate natural gas pipeline infrastructure to varying levels of natural gas demand. A reference case scenario (with assumptions for natural gas supply and demand similar to the Energy Information Administration's Annual Energy Outlook 2014 Reference case) projected the need for 38 billion cubic feet per day (Bcf/d) in interstate natural gas pipeline capacity expansions between 2015 and 2030. This includes pipeline expansions, as well as construction of new pipelines. The reference case projects the capital cost of interstate pipeline capacity additions to be about \$42 billion during the 2015 to 2030 time period.^v The reference case projection for both pipeline capacity additions and capital cost of new and expanded pipelines is consistent with (and in fact lower than) historical levels of interstate pipeline capacity additions and investment. For the period from 1998 through 2013, interstate pipeline capacity expenditures totaled more than \$63 billion, and nearly 127 Bcf/d of pipeline capacity was added.^w Analysis for the Quadrennial Energy Review projected that interstate pipeline capacity additions (see Figure B-21) are consistent with past actions that have accommodated siting, permitting, institutional, and financing constraints.^x

Figure B-21. Projected Interstate Pipeline Construction Costs by Year of Completion^y



Projected pipeline construction costs in a high-demand scenario are within the historical range.

^v Quadrennial Energy Review Analysis: Department of Energy, Office of Energy Policy and Systems Analysis. "Natural Gas Infrastructure Implications of Increased Demand from the Electric Sector." February 2015. <http://energy.gov/epsa/qer-document-library>.

^w Quadrennial Energy Review Analysis: Department of Energy, Office of Energy Policy and Systems Analysis. "Natural Gas Infrastructure Implications of Increased Demand from the Electric Sector." February 2015. <http://energy.gov/epsa/qer-document-library>.

^x Quadrennial Energy Review Analysis: Department of Energy, Office of Energy Policy and Systems Analysis. "Natural Gas Infrastructure Implications of Increased Demand from the Electric Sector." February 2015. <http://energy.gov/epsa/qer-document-library>.

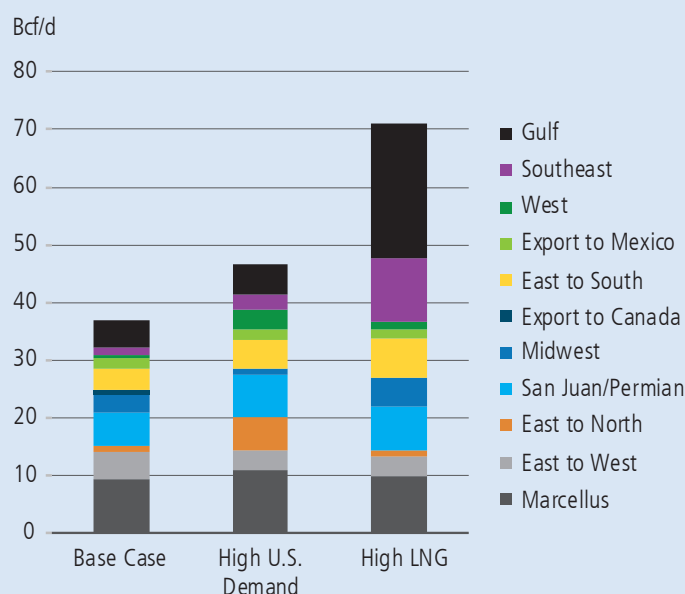
^y Quadrennial Energy Review Analysis: RAND Corporation. "Scenario Development for the 2015 Quadrennial Energy Review." 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).

Regional Trends in Pipeline Investment: Natural Gas Infrastructure Implications of Increased Demand (continued)

In addition to Deloitte MarketPoint analysis, recent reports by the Interstate Natural Gas Association (conducted by ICF) and the American Petroleum Institute (conducted by IHS) provide alternate projections for midstream infrastructure investment requirements. Unlike Deloitte's projection, ICF and IHS include processing and storage in their projections. Despite the differing methodologies by the recent projections, none of the analyses suggest an investment that is radically different from recent trends. They project between \$2.6 billion to \$7.0 billion per year in total investment for high-pressure transmission pipelines.

If natural gas demand were to increase substantially, the additional needed interstate pipeline capacity is far less than the additional needed natural gas production. Quadrennial Energy Review analysis found that for the power sector, increased switching from coal to natural gas would result in an increase of about 10 Bcf/d of production, but only 3.9 Bcf/d of new pipeline capacity additions.^z

Figure B-22. Projected Interstate Pipeline Capacity Additions, 2015–2030^{aa}



In a high U.S. demand scenario, the additional needed interstate pipeline capacity is far less than the additional needed natural gas production. Greater additions in a high LNG scenario are due to a large number of incremental additions needed in the U.S. Gulf Coast.

Similarly, if additional pipeline capacity is needed to serve up to 18 Bcf/d of natural gas exports from the Gulf region (far beyond most export predictions), annual pipeline capacity additions are within historic ranges.^{ab} While the capacity additions are greater in the high liquefied natural gas (LNG) case in comparison to the high U.S. demand case, the incremental additions in the high LNG are concentrated in the Gulf region to deliver natural gas to LNG export facilities. The capacity additions do not account for the length of pipe added (only its capacity), and numerous short pipes do not have the same cost impact as

^z Quadrennial Energy Review Analysis: Department of Energy, Office of Energy Policy and Systems Analysis. "Natural Gas Infrastructure Implications of Increased Demand from the Electric Sector." February 2015. <http://energy.gov/epsa/qer-document-library>.

^{aa} Quadrennial Energy Review Analysis: RAND Corporation. "Scenario Development for the 2015 Quadrennial Energy Review." 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).

^{ab} Energy Information Administration. "Natural gas pipeline projects from 1996 to present." <http://www.eia.gov/naturalgas/data.cfm#pipelines>. Accessed December 2014.

Regional Trends in Pipeline Investment: Natural Gas Infrastructure Implications of Increased Demand (continued)

a long-distance transmission pipe. The significant amount of short distance pipe added in the high LNG case results in a large increase of capacity in terms of billion cubic feet per day, while the projected cost increase of such a scenario is muted. This is reflected in the projected investment required in the three scenarios (shown in Figure B-22):

Interstate pipeline investments for capacity expansions (cumulative total 2015–2030):

- Reference case: 38 Bcf/d (\$42 billion)
- High U.S. demand: 46.5 Bcf/d (\$53.5 billion)
- High LNG: 71.1 Bcf/d (\$55.3 billion).

Northeast

According to Deloitte MarketPoint, the biggest additions in pipeline capacity will occur in the Northeast in order to further integrate Marcellus and Utica production into regional markets and interstate pipelines.^{ac} About 27 percent of total added capacity will strengthen the pipeline network within Pennsylvania and West Virginia to accommodate the rapid expansion of production. Another 25 percent will expand or reconfigure pipelines to other markets. Two significant projects that illustrate this trend are as follows:

- *Proposed reversal of the Transcontinental (Transco) pipeline:* Historically, natural gas flowed northward on Transco from Louisiana to the Northeast, ultimately to New York City. In the future, the flow on the northern part of the system will reverse, allowing Marcellus gas to flow as far south as South Carolina.^{ad}
- *Reversal of the Rockies Express (Rex) pipeline (underway):* The Rex pipeline was originally built to bring gas from Wyoming as far east as Pennsylvania. In the future, Marcellus gas will flow west on this pipeline as far as Missouri.^{ae}

Southwest

Deloitte MarketPoint projects that about one-fifth of the Nation's total pipeline expansion will go to reinforce the Southwestern pipeline network (not including lines designed mostly to serve Mexican exports).^{af} Ultimately, many of these additions help grow demand for electric power, mostly in California, not by building new long-haul pipelines, but by increasing the connectivity of the pipeline network to allow under-used segments to operate more efficiently. For example, the largest Western project is to increase the capacity of the Havasu crossover that links the northern and southern branches of the El Paso system. This will allow more gas to flow into California on the southern leg, which is not fully used now.

Northwest

In contrast to 2000–2010, Deloitte anticipates almost no new pipeline expansions in the Northwest.^{ag}

^{ac} Quadrennial Energy Review Analysis: RAND Corporation. "Scenario Development for the 2015 Quadrennial Energy Review." 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).

^{ad} RBN Energy LLC. "They Long To Be Close To You—Moving Marcellus/Utica Natural Gas South And West." May 15, 2014. <https://rbnenergy.com/they-long-to-be-close-to-you-moving-marcellus-utica-gas-south-and-west>.

^{ae} RBN Energy LLC. "They Long To Be Close To You—Moving Marcellus/Utica Natural Gas South And West." May 15, 2014. <https://rbnenergy.com/they-long-to-be-close-to-you-moving-marcellus-utica-gas-south-and-west>.

^{af} Quadrennial Energy Review Analysis: RAND Corporation. "Scenario Development for the 2015 Quadrennial Energy Review." 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).

^{ag} Quadrennial Energy Review Analysis: RAND Corporation. "Scenario Development for the 2015 Quadrennial Energy Review." 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).

Regional Trends in Pipeline Investment: Natural Gas Infrastructure Implications of Increased Demand (continued)

Midwest

Deloitte MarketPoint projects two major pipeline expansions in the Midwest: one to deliver gas from Tuscola in southern Illinois to Chicago and one to deliver gas from Chicago to Canada.^{ah} Tuscola represents a major hub that can redirect gas from the East, West, and Southeast as supply and demand conditions warrant. These two projects account for 15 percent of projected capacity additions and 18 percent of additional costs.^{ai}

Southeast

Deloitte MarketPoint projects that only about 5 percent of additional capacity will be needed to serve the Southeast, especially to create more deliverability to Georgia.^{aj} Deloitte projects only two relatively small expansions in producing areas of the Southeast: one between Louisiana offshore and Mobile Bay (0.47 Bcf/d) and another from Katy to Houston Ship Channel in east Texas (0.07 Bcf/d). In effect, the pipeline network in the Southeast is already designed to handle large natural gas flows to distant parts of the country and needs little expansion to handle new flows within a more constricted region.

U.S. Exports to Mexico

Deloitte MarketPoint also projects three expansions to export U.S. natural gas to Mexico, which together account for about 4 percent of total expansions.^{ak}

^{ah} Quadrennial Energy Review Analysis: RAND Corporation. “Scenario Development for the 2015 Quadrennial Energy Review.” 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).

^{ai} Quadrennial Energy Review Analysis: RAND Corporation. “Scenario Development for the 2015 Quadrennial Energy Review.” 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).

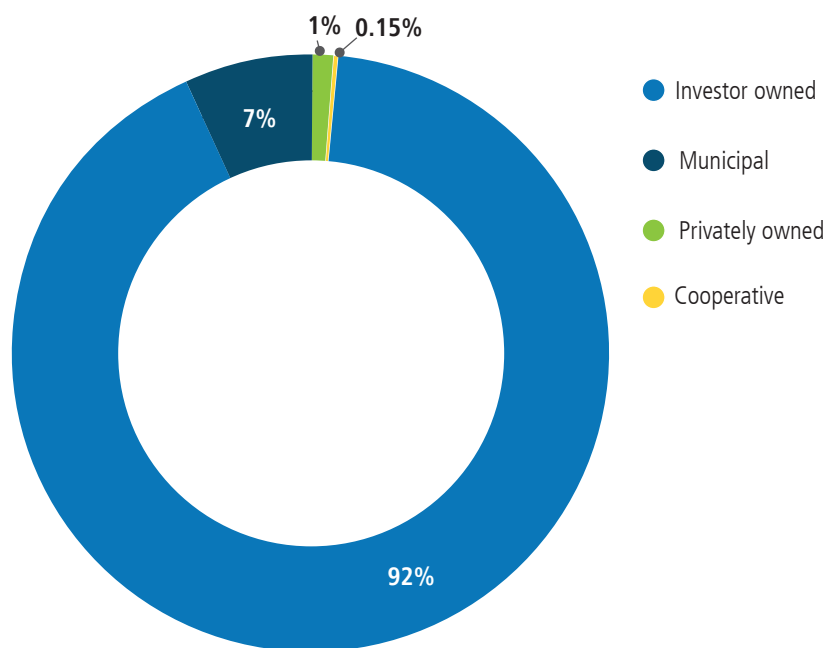
^{aj} Quadrennial Energy Review Analysis: RAND Corporation. “Scenario Development for the 2015 Quadrennial Energy Review.” 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).

^{ak} Quadrennial Energy Review Analysis: RAND Corporation. “Scenario Development for the 2015 Quadrennial Energy Review.” 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).

Distribution Pipelines

In 2013, the United States had 1,437 distribution systems comprised of more than 2.1 million miles of distribution lines that deliver gas from high-pressure pipelines to more than 68 million residential and 5 million commercial customers.¹⁵¹ The function of the U.S. natural gas distribution infrastructure is to take large, high-pressure supplies of natural gas and deliver this supply across wide geographic areas to customers. LDCs provide retail distribution service to natural gas customers. LDC firms include several different types of business organizations, but all are organized with the objective of selling and/or transporting natural gas to specific customer groups.¹⁵² LDC firms are either investor owned,¹⁵³ privately owned,¹⁵⁴ municipally owned,¹⁵⁵ or a cooperative.¹⁵⁶ The majority of customers are served by an investor-owned LDC (see Figure B-23).

Figure B-23. Fraction of Total Customers Served by LDC Ownership Type¹⁵⁷

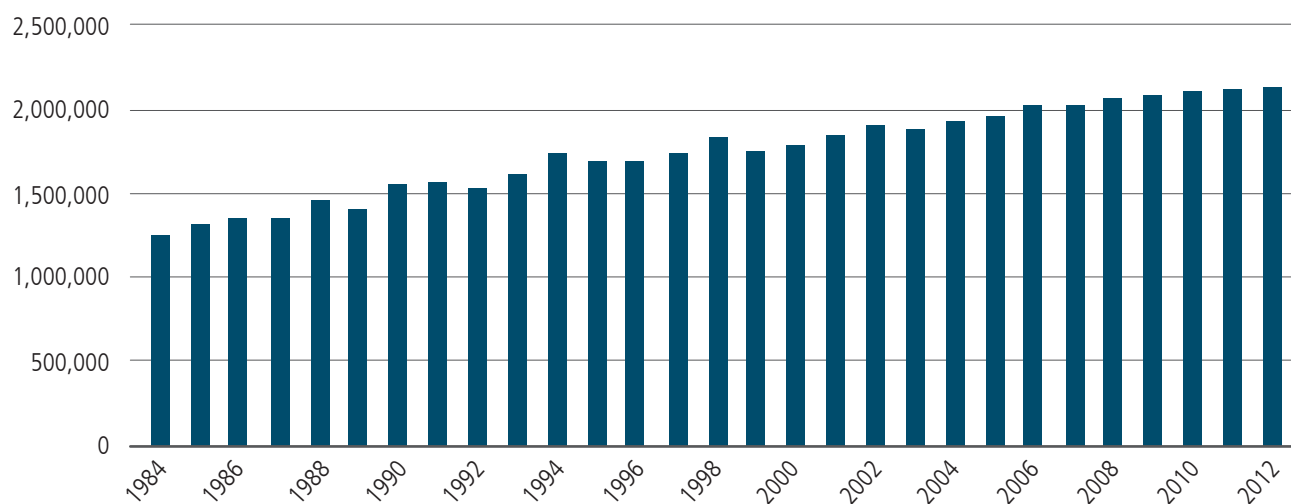


The majority of customers are served by investor-owned LDCs; however, the area covered by different types of LDCs could vary significantly.

Natural gas is distributed by mains and service lines. Distribution mains serve as a common source of supply for multiple service lines, and service lines deliver gas to customers. According to the Department of Transportation, the United States had more than 2 million miles of distribution mains and service lines in 2012 (see Figure B-24).

Figure B-24. U.S. Natural Gas Total Distribution Main and Estimated Service Mileage, 1984–2012¹⁵⁸

Miles of Pipeline



There are more than 2 million miles of distribution main pipelines in the United States.

Distribution mains deliver virtually all of the natural gas to small customers, and both distribution and high-pressure transmission lines deliver natural gas to larger customers, such as electric power generators and industrial users.¹⁵⁹ The distribution infrastructure covers most of the U.S. population, but there are two notable exceptions: remote areas where distribution lines are uneconomic and some urban areas that were developed during the period when Federal wellhead price controls were in place and new gas distribution lines were prohibited due to concerns about domestic gas availability.¹⁶⁰

From 1986 to 2004, more than 650,000 miles of distribution pipeline were added to the system.¹⁶¹ Total capital expenditures for natural gas distribution increased 30.5 percent from 2010 to 2011. Companies spent \$8.1 billion on natural gas distribution in 2010 and \$10.6 billion in 2011.¹⁶²

Natural Gas Transmission, Storage, and Distribution System Reliability and Resilience

The natural gas system serving residential and commercial customers is designed to have a high level of reliability. Local distribution companies, managing delivery of gas to residential consumers, have requirements to ensure reliability and recourse to recover costs for gas contracts that have high certainty of delivery, and generally have adequate incentives in place to build needed infrastructure. This infrastructure includes storage, which is needed for normal operation to address seasonal variation in gas demand and to ensure the reliable delivery of natural gas for home heating. Even with increasing use of gas for electricity generation, the massive interstate bulk gas delivery system generally is resilient given the presence of storage facilities, latent pipeline capacity, and options for re-routing gas for many regional transfers.

Disruptive Events: Freeze-Offs

The potential for disruptions associated with freeze-offs—in which liquids in the wellhead freeze and block the flow of gas—has increased relative to the potential for disruptions associated with tropical storm activity in part due to the changing geography of natural gas production.^{al} Historically, natural gas production was highly susceptible to disruptions from tropical storms, as a large portion of natural gas was produced from Federal offshore formations in the Gulf of Mexico.^{am} In 1997, 26 percent of the Nation's natural gas was produced in the Gulf of Mexico; in 2012, however, only 6 percent of the Nation's natural gas was produced from this region.^{an}

There are now higher levels of production taking place at inland basins, which generally are less affected by storms, but are susceptible to outages from freeze-offs.^{ao} Since 2008, freeze-offs have contributed to initial daily disruptions as much as all but the largest hurricanes (see Figure B-25).^{ap}

^{al} Energy Information Administration. "Winter supply disruptions from well freeze-offs can rival effects of summer storms." *Today in Energy*. October 6, 2011. <http://www.eia.gov/todayinenergy/detail.cfm?id=3390>. Accessed October 20, 2014.

^{am} Quadrennial Energy Review Analysis: BENTEK Energy. "The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments." 2014. <http://energy.gov/epsa/qer-document-library>

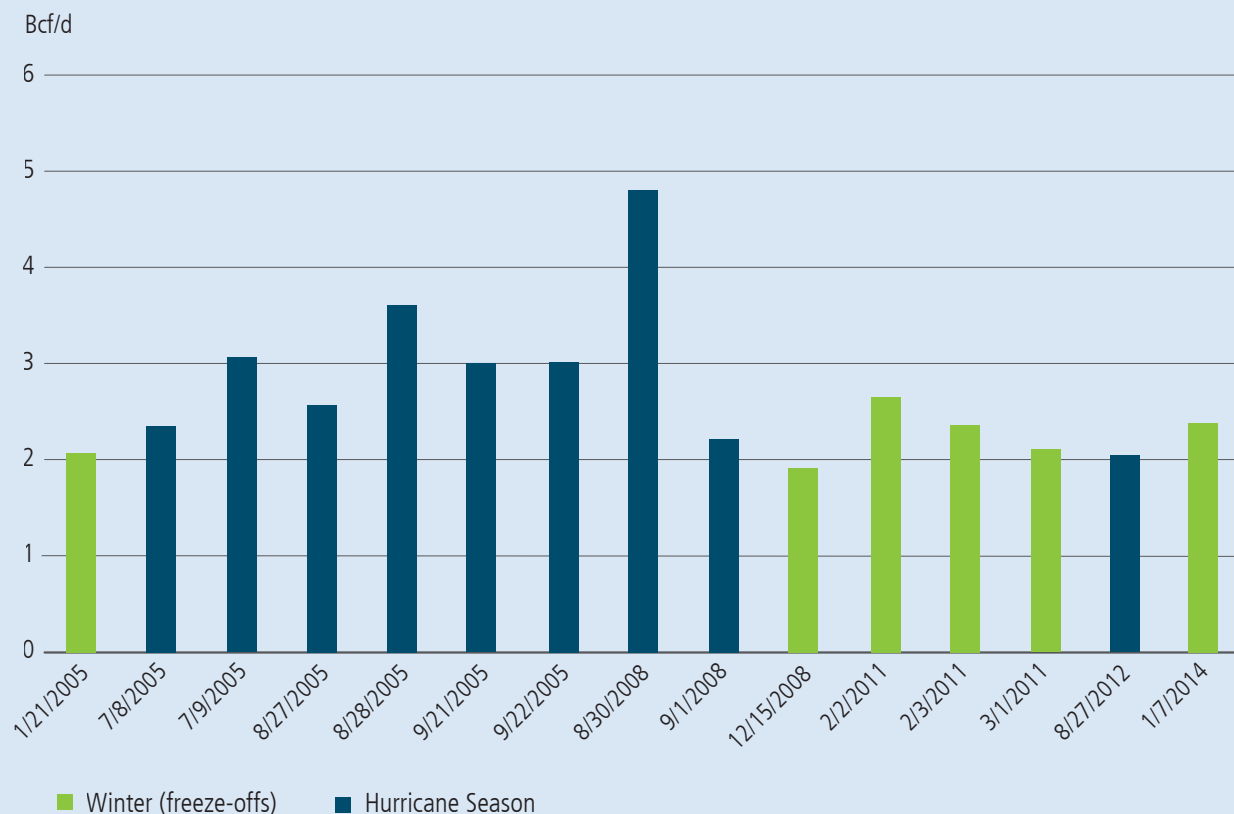
^{an} Energy Information Administration. "Winter supply disruptions from well freeze-offs can rival effects of summer storms." *Today in Energy*. October 6, 2011. <http://www.eia.gov/todayinenergy/detail.cfm?id=3390>. Accessed October 20, 2014.

^{ao} Energy Information Administration. "Natural Gas 2014: Natural Gas Gross Withdrawals and Production." September 30, 2014. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm. Accessed October 20, 2014.

^{ap} Energy Information Administration. "Winter supply disruptions from well freeze-offs can rival effects of summer storms." *Today in Energy*. October 6, 2011. <http://www.eia.gov/todayinenergy/detail.cfm?id=3390>. Accessed October 20, 2014.

Natural Gas Transmission, Storage, and Distribution System Reliability and Resilience (continued)

Figure B-25. The 15 Largest Daily Natural Gas Dry Production Disruptions (Bcf/d) by Season, January 1, 2005–May 29, 2014^{aq}



While freeze-offs generally present smaller challenges to the pipeline network than hurricanes because the damage is temporary, since 2008, freeze-offs have contributed to initial daily disruptions as much as all but the largest hurricanes.

In general, freeze-offs present a smaller challenge to the natural gas pipeline network than hurricanes. Any damage from a freeze-off is temporary, and the outages are typically shorter than those associated with hurricanes.^{ar} Department of Energy Office of Energy Policy and Systems Analysis gas system modeling^{as} under a month-long freeze-off scenario in the Marcellus gives some indication that losing the wet gas production in the Marcellus region in a month-long freeze-off (10 percent of U.S. gas production) would not result in catastrophic gas delivery disruptions, with the model showing deep draws of gas from storage and adjustment of interregional pipeline flows. However, further work is needed to explore short-term dynamics under a disruption scenario. The model did not capture the high probability of significant short-term price spikes, nor did the model

^{aq}Quadrennial Energy Review Analysis: BENTEK Energy. "The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments." 2014. <http://energy.gov/epsa/qer-document-library>.

^{ar}Energy Information Administration. "Winter supply disruptions from well freeze-offs can rival effects of summer storms." Today in Energy. October 6, 2011. <http://www.eia.gov/todayinenergy/detail.cfm?id=3390>. Accessed October 20, 2014.

^{as}Quadrennial Energy Review Analysis: Tenney, C. and L. Pierpoint. "Simulation and Analysis of North American Natural Gas Supply and Delivery During a Winter High-Demand Event with Loss of Marcellus Production." Sandia National Laboratories and Department of Energy, Office of Energy Policy and Systems Analysis. 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).

Natural Gas Transmission, Storage, and Distribution System Reliability and Resilience (continued)

include institutional barriers that could prevent the region-to-region gas transfers that reduce the severity of gas shortages and associated high gas (and electricity) prices.^{at}

However, freeze-offs do occur during periods when parts of the country are suffering from extreme cold weather and natural gas for heating is in demand. Traditionally, freeze-offs occurred in regions distant from major consuming markets (like west Texas and the San Juan Basin) and may have been subject to different weather patterns than consuming markets. As production shifts to areas closer to major consuming markets like the Northeast, freeze-offs could become increasingly important. During the recent southward shift of the polar vortex and resulting extreme cold conditions in the Northeast during the winter of 2013-2014, freeze-offs occurred in liquids-rich parts of the Marcellus Basin. Estimates suggest that outages totaled nearly 0.9 billion cubic feet per day in the Marcellus during peak cold conditions.

While any pressure drop in a pipeline can cause hydrate formation, added cooling from cold weather exacerbates the problem. Pressure drops in pipelines can be caused by rough pipe interiors, sharp bends, and other flow line restrictions. These can be mitigated by ensuring good welds that do not result in welding slag sticking out into the center of the flow line. Burying flow lines also serves as protection from dropping air temperatures. The risk of hydrate formation also increases with higher liquids content, both hydrocarbon liquids and produced water.

The Gas Technology Institute identifies a number of techniques that can be applied to prevent freezing at gas wells.^{au} The most common technique is to inject methanol into the annulus of the wellbore or into a pipeline system to lower the freezing point of the gas and decrease hydrate formation. Application of direct heat in locations prone to pressure drops provides a localized response for freeze-offs. While most freeze-offs occur upstream of the heater treater, raising the heater treater operating temperature can also prevent downstream hydrate formation. The Gas Technology Institute has estimated winterization equipment costs at \$34,425 per well, with operating costs of \$6,800 for 5 months.

^{at} The model assumes an economically optimal solution under the disruption; if gas transfers are not possible between some regions, disruptions or price spikes are more likely to occur, particularly on short timescales.

^{au} Perry, K.F. "Impact of Cold Weather on Gas Production in the Texas and New Mexico Gas Production Regions of the United States During Early February 2011." Gas Technology Institute. 2011.

Natural Gas and Electricity Interdependence

This section characterizes the interdependencies between natural gas and electricity, describes regional trends, and discusses the impacts on investment, infrastructure, and reliability.

Historically, natural gas has been used primarily for heating purposes. However, beginning in the late 1990s, natural gas is increasingly used to generate electricity. The advent of combined-cycle generation capacity additions also spurred natural gas-fired generation. Since 2005, because of higher load factors brought on by lower fuel costs and increased availability from the shale gas revolution, natural gas-fired power generation has increased more than 40 percent. The increasing absolute demand for natural gas in the power sector and increased share of gas in the power generation mix has heightened the interdependence between gas and electric systems. In addition, fast-ramping attributes of natural gas-fired generation, often applied to firm renewable generation, are placing additional operational expectations on gas infrastructure.

The natural gas market and the electricity generation industry each have unique scheduling procedures, market timings, communication protocols, and service mandates. As the two sectors become more interdependent, greater coordination is necessary. As such, FERC and industry have ongoing efforts in areas such as the sharing of operational and non-public information, generator fuel cost recovery, scheduling, capacity resources, and fuel diversity.¹⁶³

In particular, the growing penetration of renewable energy through 2030 could lead to additional natural gas transmission operations. Balancing intermittent renewable resources often requires the use of additional complementary power generation or demand-side resources that can quickly ramp up and down to follow net load. Natural gas-fired generators generally are well-suited to provide this service, but gas delivery systems must accordingly be prepared to support fast-ramping by natural gas-fired generators.

Summary of Regional Trends in Gas/Electricity Interdependence

Currently, different regions of the United States have different levels of penetration of gas-fired and renewable generation, and the regional variation in market structures and other factors mean the coordination needs associated with gas-electric interdependency are not nationally uniform.

Midwest

In the Midwest, the Midcontinent Independent System Operator (MISO) forecasts significant coal plant retirements in the near future; these plants will likely be replaced by natural gas power plants. MISO conducted a review of pipeline infrastructure adequacy in order to understand the implications of growing use of natural gas in the MISO generation portfolio for the changing utilization of interstate pipelines in the region. The analysis projected that, from 2011 out to 2030, new investments of more than \$3 billion will be required to serve the incremental natural gas storage and transmission needs of the power sector.^{av} For context, there has been significant investment in new interstate pipeline capacity over the last 18 years for which data are available, with more than 133 billion cubic feet per day of capacity additions and \$65 billion in capital expenditures.^{aw} Investment is expected to continue.

Southwest

In Texas, there is a large supply of regional natural gas. Electric reliability concerns in the state are driven by hurricanes in the Gulf of Mexico that can massively reduce natural gas availability, as well as rare extreme cold events that can (and have) resulted in large loss of production capacity due to freeze-offs (see the Natural Gas Transmission, Storage, and Distribution System Reliability and Resilience box).

In February 2011, the Southwest experienced a severe cold weather event and, for a 4-day period, temperatures in Texas remained below freezing, leading to a number of key infrastructure failures in both the electric and gas sectors. In the electric sector, the extreme cold weather contributed directly to an unusually large number of plant outages in the Southwest. In the gas sector, many wells in the Permian Basin of west Texas experienced freeze-offs and the loss of gas pumping units and compressors on gathering lines due to the blackout. Gas distribution companies serving loads across the Southwest were forced to curtail customers, including electric generators, which exacerbated challenges in the gas sector.^{ax} Ultimately, this event had material impacts as far downstream as California.

Southeast

The Southeast already has strong coordination capabilities, in part because the markets are dominated by vertically integrated utilities with the ability to recover investments in gas transmission and storage infrastructure. These utilities have greater autonomy over their natural gas transportation contract portfolios, which directly affect infrastructure investment and operation. For example, Florida Power & Light has nearly all of its gas delivery through firm contracts, as well as access to significant levels of high-deliverability storage from neighboring states, backup fuel requirements for gas-fired generation, and a high reserve margin for electric generation.

^{av} Midcontinent Independent System Operator. "Gas-Electric Infrastructure Analyses I, II." 2013. <https://www.misoenergy.org/Library/Repository/Communication%20Material/One-Pagers/Gas%20Infrastructure%20Analyses.pdf>. Accessed July 22, 2014.

^{aw} Department of Energy. "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector." February 2015. <http://energy.gov/epsa/qer-document-library>.

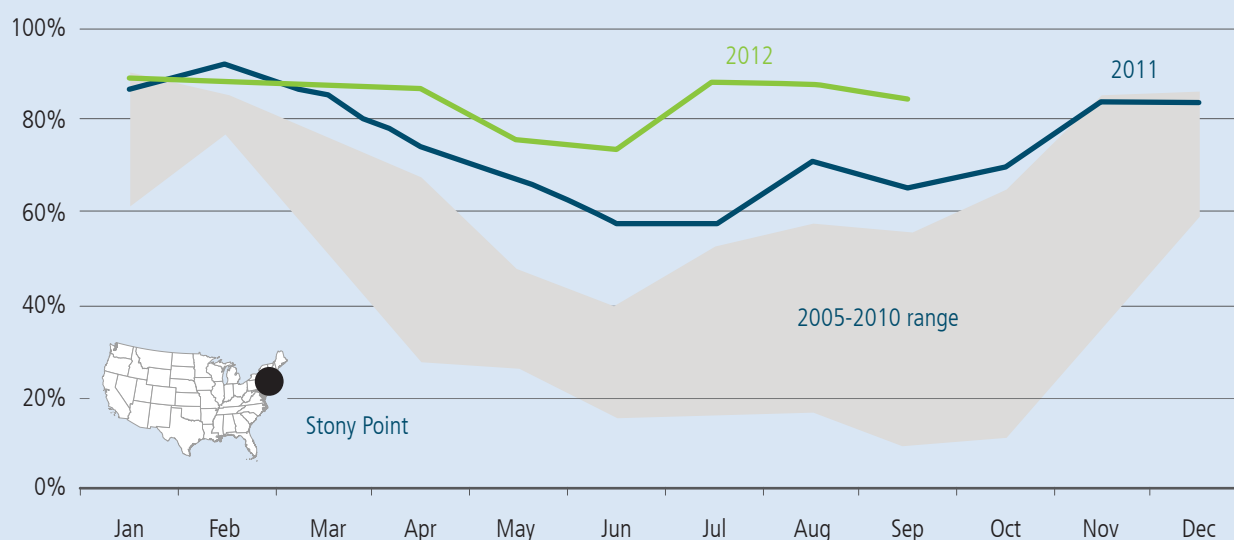
^{ax} Federal Energy Regulatory Commission. "Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011." August 2011. <http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf>.

Summary of Regional Trends in Gas/Electricity Interdependence (continued)

Northeast

Much of the northeastern Atlantic region (New England, New York, and—to some extent—the Mid-Atlantic states) continues to see natural gas transmission capacity constraints, especially during cold winter periods. The Northeast has experienced a large increase in natural gas use in the power sector, which has led to a greater year-round utilization of pipelines (see Figure B-26).^{ay}

Figure B-26. Monthly Average Flows of Natural Gas into New England along the Algonquin Transmission Pipeline^{az}



The Algonquin transmission pipeline is one of two main pipelines serving the New England region. As gas-fired generation has utilized interruptible contracts (which primarily consists of capacity firm contract owners, typically local distribution companies, who are not utilizing until the winter peak) to meet the growing summer demand for air conditioning, the Algonquin pipeline has seen changes in its year-round utilization.

The Northeast region is located at the end of major pipeline routes from traditional natural gas producing areas. Its supplies of natural gas have tended to be constrained during winter peak periods, allowing prices to rise much higher in this region than in the rest of the country in recent years.^{ba} For example, natural gas prices rose to greater than \$34 per million British thermal unit during cold snaps in the winter of 2012-2013 and increased to more than \$73 per million British thermal unit during the southward shifts in the polar vortex in the winter of 2013-2014.^{bb} However, during the winter of 2014-2015, prices moved dramatically lower, peaking at just less than \$30 per million British thermal unit in February 2015.^{bc} A number

^{ay} For more detailed discussion of infrastructure constraints in the New England area, see the documents relating to the April 21, 2014, Quadrennial Energy Review Stakeholder Meeting: “New England Regional Infrastructure Constraints.” <http://energy.gov/epsa/downloads/qer-public-meeting-providence-ri-hartford-ct-new-england-regional-infrastructure>.

^{az} Energy Information Administration. “Key New England natural gas pipeline reflects seasonal flow changes.” Today in Energy. October 3, 2012. <http://www.eia.gov/todayinenergy/detail.cfm?id=8230>.

^{ba} Netusil, M. and P. Dittl. “Comparison of three methods for natural gas dehydration.” Journal of Natural Gas Chemistry. 20. 2011. p. 471-476. http://ac.els-cdn.com/S1003995310602186/1-s2.0-S1003995310602186-main.pdf?_tid=d73de138-3da3-11e4-a27a-00000aabb0f6c&acdnat=1410873642_a41ae3ee8d37bee386876d0b6c25b927. Accessed February 26, 2015.

^{bb} Federal Energy Regulatory Commission. “Winter 2013-2014 Operations and Market Performance in RTOs and ISOs.” April 1, 2014. <http://www.ferc.gov/CalendarFiles/20140424112341-Transcript0401technical.pdf>. Accessed March 2, 2015.

^{bc} Energy Information Administration. “Natural Gas Weekly Update.” February 26, 2015. http://www.eia.gov/naturalgas/weekly/archive/2015/02_26/index.cfm. Accessed April 1, 2015.

Summary of Regional Trends in Gas/Electricity Interdependence (continued)

of factors contributed to the lower and less volatile prices observed in the 2014-2015 winter, including increased natural gas production, abundant storage inventories, increased pipeline capacity, and better gas-electric coordination, as well as Independent System Operator and Regional Transmission Organization programs that improved operational performance and the availability of gas-fired electric generating units.^{bd} Constraints have emerged as growing use of natural gas in the electric power sector in New England in recent years coincides with peak residential and commercial natural gas demand. Despite large volumes of new unconventional gas resources available from the Marcellus Shale in nearby Pennsylvania, pipeline constraints have not allowed sufficient supplies of this gas to reach New England, resulting in upward pressure on prices at gas delivery points in New England. The New York metropolitan area, by contrast, has alleviated some of the winter congestion it had faced by adding new pipeline capacity.

The underlying issues affecting natural gas prices in New England are caused by several complex factors. One area of concern has been the role of capacity markets in the challenges associated with assuring access to adequate fuel supplies. Independent System Operator New England has taken a number of steps to address this issue, including implementing changes to its capacity markets to enhance generator performance and adopting winter reliability measures designed to address this concern.^{be, bf} Another issue has been public acceptance of new pipelines, especially in New England, which presents a substantial challenge to natural gas pipeline development.^{bg} Several pending pipeline projects would alleviate infrastructure constraints into New England. In addition to the capacity market changes by Independent System Operator New England previously described, the New England governors are formulating proposals to pay for new natural gas pipeline and electric transmission capacity and services.

^{bd} Federal Energy Regulatory Commission. “2014 State of the Markets.” p. 17–21. March 19, 2015. <http://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2014-som.pdf>. Accessed April 1, 2015

^{be} ISO New England Inc. 148 FERC ¶ 61,179. 2014.

^{bf} ISO New England Inc. 147 FERC ¶ 61,172. 2014.

^{bg} Epp, H. “Proposed Natural Gas Pipeline Across Northern Massachusetts Stirs Up Debate.” New England Public Radio. May 2, 2014. <http://nepr.net/news/2014/05/02/proposed-natural-gas-pipeline-across-northern-massachusetts-stirs-up-debate/>. Accessed February 26, 2015.

Interdependency Impacts

Investment in Transmission Pipelines

Traditionally, natural gas LDCs sponsored most new pipeline capacity to meet their peak needs by signing long-term firm service contracts. This gave pipeline companies a stable flow of payments to cover their capital costs. LDCs, in turn, recovered the costs through their distribution rates.

Generators, however, have often used interruptible transportation service to obtain their natural gas, given they have uncertain gas needs. This is an approach that can work when there is excess pipeline capacity, or when serving peak summer electric power in regions like the Northeast that have natural gas peaks in the winter. However, few market participants have an incentive to sponsor new pipeline capacity that could help serve peak winter load; in some restructured markets, gas generators are not penalized for failing to serve load if they cannot get gas, but do stand to lose if they increase costs by purchasing long-term contracts. However, this is changing, and the actions undertaken by the ISOs, RTOs, and market participants—such as PJM’s Cold Weather Preparation Guidelines and the continuation of ISO New England’s Winter Reliability Program for a second winter—have improved operational performance and moderated prices.¹⁶⁴

In transmission-constrained regions and regions where gas needs for backstopping intermittent renewables are high, additional investments in reliability and flexibility of natural gas used for electricity generation could be required in the long term. However, these needs will vary by region. A high-deliverability market area or onsite

storage can provide both flexibility and reliability. Pipeline capacity expansions can increase the opportunity for greater line packing and gas delivery flexibility. Switching to other fuel sources, as well as gas or electricity demand-side management, can also reduce demand for gas.

Natural Gas Transmission Dependence on Electricity

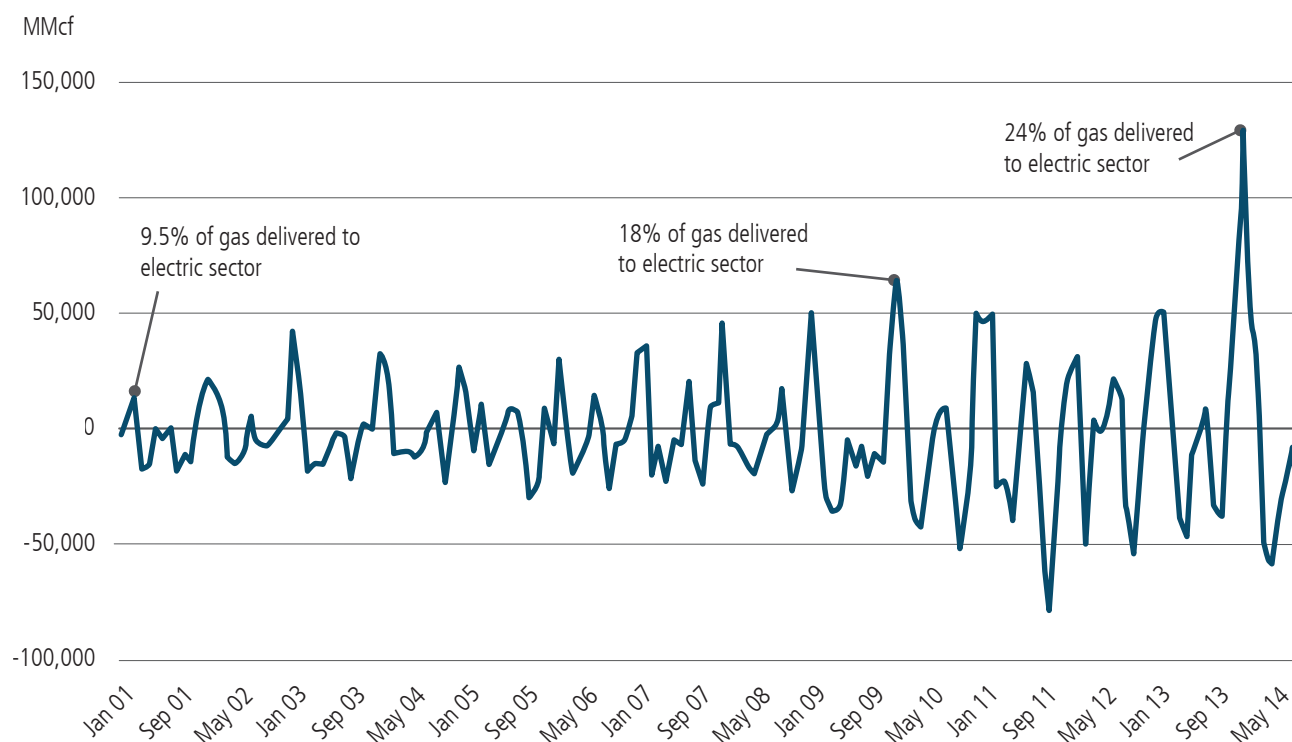
Natural gas pipeline systems are not heavily reliant upon the electricity and the liquid fuels systems—only 5 percent of installed compression horsepower on interstate pipelines nationwide require electricity to run.¹⁶⁵ Whereas the national average is 5 percent, there is a significantly greater reliance on electric compressors in some regions, particularly Pennsylvania and Ohio.¹⁶⁶ These regional differences are due in part to the reduced emissions and increased speed of permitting of electric compressors over those powered by natural gas.¹⁶⁷ Any trends toward increased electrification of natural gas compressor stations without appropriate backup systems could increase the system vulnerability to electricity disruptions. As an example, during the 2011 Southwest gas crisis, rolling electricity blackouts contributed to natural gas production outages (due to electric powered compressors on gathering lines) of up to 27 percent or at least 1 Bcf. These interruptions in turn led to power generation curtailments (10 percent of the number of units that failed to start were caused by gas supply problems), exacerbating the electric sector challenges.¹⁶⁸ In light of this event, system operators should continue to be mindful of such system dependencies as they develop their networks.

Gas Storage for Meeting Changing Electricity Demands

As natural gas has become an increasingly critical component of the generation mix, one option for supplying electricity generators with gas flexibility includes high-deliverability storage. Investments in gas storage through at least 2011 appear to be keeping pace with system needs, but a decline in seasonal gas price variation could slow the investment trajectory. In recent years, this investment has decreased as seasonal price differentials—which are vital to the economics of storage—have declined due in part to increased use of gas for powering electricity-driven air conditioning in recent summers.¹⁶⁹ Furthermore, the majority of existing salt cavern storage resides in the Southeast in salt dome formations and is not necessarily coincident with other areas of increasing gas demand. Salt cavern storage is geographically limited to salt deposits, which exist in the Gulf, Pennsylvania, Ohio, Michigan, parts of New York, and parts of the Midwest and Southwest.¹⁷⁰

High-deliverability storage is primarily used for increasing gas supply to provide for changes in electric demand because of its high deliverability and high-cycling rates. While salt cavern storage capacity additions have decreased (see the Natural Gas Storage Investment section), this type of storage has seen a large increase in utilization (net withdrawal and injection) in recent years (see Figure B-27). The increase in salt storage utilization coincides with the increased utilization of gas use for the electric sector.

Figure B-27. Net Withdrawals from Salt Cavern Storage (million cubic feet)¹⁷¹



The increase in salt storage utilization coincides with the increased utilization of gas use for the electric sector. When considering net activity as a percentage of gas delivered to the electric sector, the peak tends to be around 15 percent for most winters (however, it reached 24 percent during the polar vortex).

Line Packing Flexibility and Demand Response

Line Packing serves to temporarily increase the amount of gas within a pipeline, and this additional available gas can supply those types of generating units that help facilitate fast ramping of power generation to support renewables. However, line packing is not a substitute for storage because imbalances on the pipeline affect the ability of the line to deliver gas, and pipeline operators could need to limit flow rates in response.¹⁷² Utilizing electric demand response can also help mitigate reliability risks. For example, during the winter of 2013-2014, demand-response resources were also used to help alleviate electricity reserve shortages.^{bh} There currently are limitations to demand response; for example, while ISO New England includes demand response as a portion of its winter reliability program this year, there can be no more than two dispatches per day with a minimum of 4 hours between each dispatch. Additionally, the demand-response asset limit has been decreased from 200 to 100 due to the amount of manual work required to calculate the performance and settlement computation.¹⁷³ However, changes to ISO New England's demand response program are underway^{bi} to fully integrate demand-side resources into regional markets by 2017 so that demand response can be dispatched, on par with generating resources, whenever it is cost effective to do so.^{174, 175}

^{bh} For example, on December 14, 2013, all of the demand-response resources with positive net capacity supply obligations were dispatched. This totaled 248 MW of demand response and, on average, this accounted for approximately 77 percent of the total load reduction, helping to mitigate the electricity capacity deficiency on the system.

^{bi} The tariff revisions are tied to FERC Order 745, which vacated and was recently appealed to the Supreme Court. While FERC has approved the ISO New England demand-response plan, the outcome of the court case could influence the program going forward.

Gas-Electricity Scheduling Coordination

Market days for gas and electricity sectors are not aligned. Nationally, the single gas-scheduling day begins at 9:00 a.m. Central Time—well after regionally defined electricity days begin.^{bj} One example of better coordination—increasing the number of nomination cycles—would improve the ability of gas-fired generation to adapt unexpected scheduling changes due to electricity demand and could lead to more stable levels of line pack.¹⁷⁶

FERC has recently issued a Notice of Proposed Rulemaking that seeks comment on whether and how to better align the gas and electric days and offer generators more opportunities for intraday trading.^{bk} While there has been agreement that changes to nomination cycles are necessary, viewpoints on efforts to improve alignment of gas and electric days are split, with the majority of the gas industry supporting a 9:00 a.m. Central Time start and the majority of the electricity industry supporting a 4:00 a.m. Central Time start. The debate varies by region, and one solution will not fit all. Ongoing coordination between gas transmission systems and electricity generators is needed to support stability and affordability in both markets. In its “2014 State of the Markets Report,” FERC noted that “...another factor helping moderate prices was better gas-electric coordination. Gas-electric coordination initiatives, which FERC began to actively encourage in 2011, led to concrete actions by participants in both industries. These efforts have enhanced communications and understanding across these industries, and have reduced or eliminated some of the language barriers that up until recently were common.”¹⁷⁷

Public Safety, Greenhouse Gas Emissions, Energy Efficiency, and Air Quality

The primary externalities associated with the natural gas TS&D include public safety, greenhouse gas (GHG) emissions, and air quality. Natural gas TS&D facilities present several key opportunities for infrastructure investments that can improve safety, increase energy efficiency, and enhance environmental performance while expanding employment opportunities. For example, replacing older, leak-prone natural gas distribution pipelines supports thousands of jobs¹⁷⁸ while reducing methane emissions, in line with the President’s “Climate Action Plan”¹⁷⁹ and Strategy to Reduce Methane Emissions.¹⁸⁰

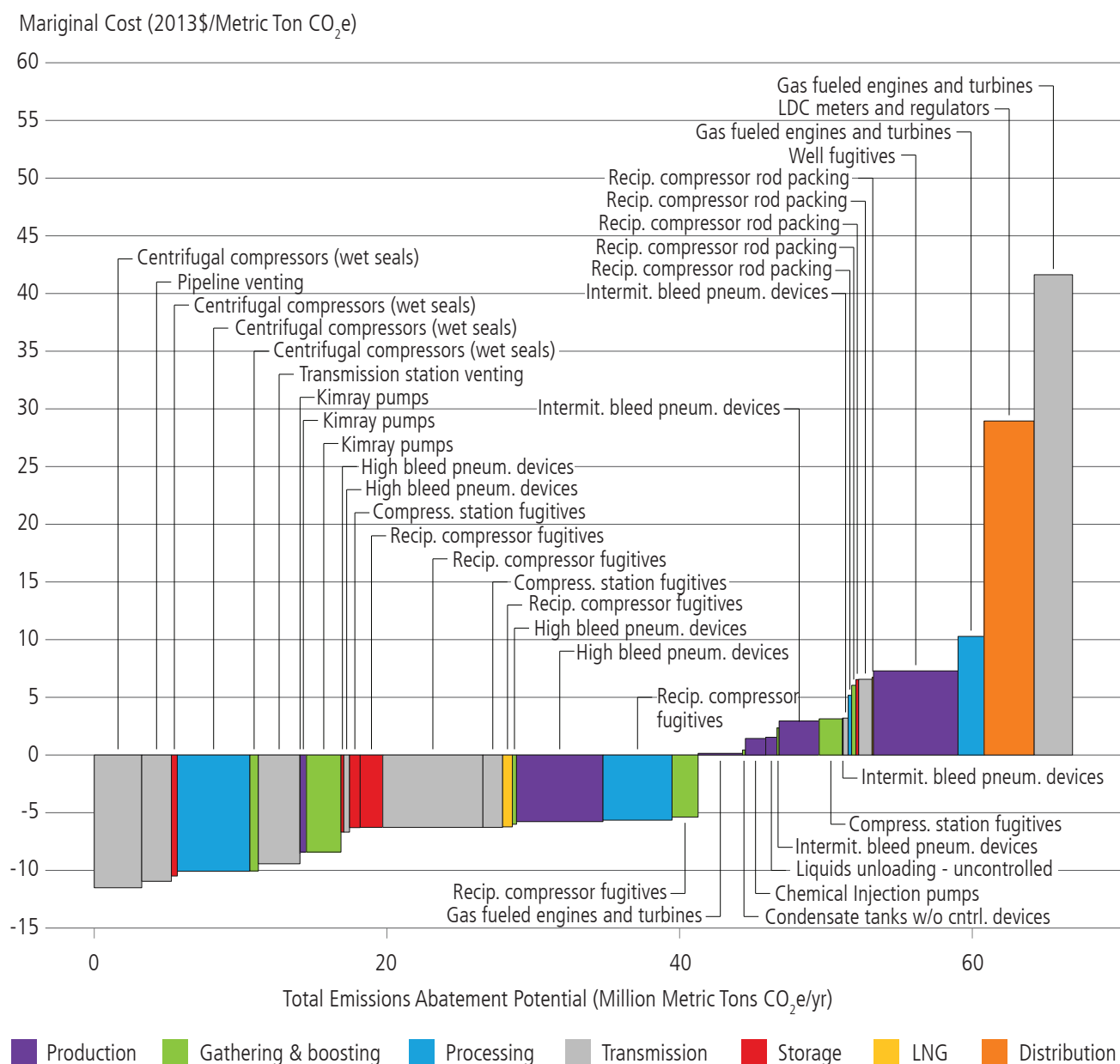
As shown in Figure B-28, a number of actions to reduce leakage of natural gas—and therefore methane—would have net cost savings if the value of the natural gas could be monetized. However, monetizing the savings is not always straightforward.^{bl} For example, “principal-agent” problems are common in the natural gas industry. In many instances, the companies that are in a position to take actions that would reduce leakage are often not able to accrue the monetized gas savings. Those savings accrue to other actors, or they are unable to be realized (e.g., because their economic regulators do not allow for the cost of infrastructure upgrades to be passed on to consumers). Thus, a number of the QER recommendations in this arena are about enabling these actors to recover the costs of infrastructure investments as appropriate.

^{bj} Electricity operation and market days are set on a regional basis. In the morning, generators submit their offers to the electricity system operators. Those offers are confirmed in the afternoon, and the electricity operations begin very early the following morning.

^{bk} The proposed changes would move the natural gas day earlier (to 4:00 a.m. Central Time) to be more in line with that of electricity; move the timely and evening nomination cycles to 1:00 p.m. and 6:00 p.m. Central Time, respectively; and increase opportunities for intraday capacity nominations.

^{bl} Other examples of challenges to monetizing savings include price competition among pipeline transmission service providers to attract and retain customers in the regulated marketplace, which creates uneven incentives for companies to invest in efficiency and methane emission reductions. In addition, rate structures often create uncertain cost recovery and high hurdle rates for capital investments by companies.

Figure B-28. Total Emissions Abatement Potential (million metric tons carbon dioxide (CO₂) equivalent per year)^{181, bm, bn}



Assuming full revenue recovered from the sale of captured natural gas, an estimated 40 million metric tons of CO₂ equivalent of methane emissions abatement could be achieved at a negative marginal cost; under this scenario, at a marginal cost below the Social Cost of Carbon, all segments of natural gas infrastructure have potential opportunities for cost-effective methane abatement. **Acronyms:** intermittent (intermit.); pneumatic (pneum.); local distribution company (LDC); liquefied natural gas (LNG); reciprocating (recip.).

^{bm}The Social Cost of Carbon is a metric that monetizes the societal benefits and costs of emitting an additional ton of carbon. The Social Cost of Carbon at a 3 percent discount rate in year 2015 and in 2015 dollars is \$43 per ton carbon dioxide. Source: Interagency Working Group on Social Cost of Carbon. "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866." May 2013.

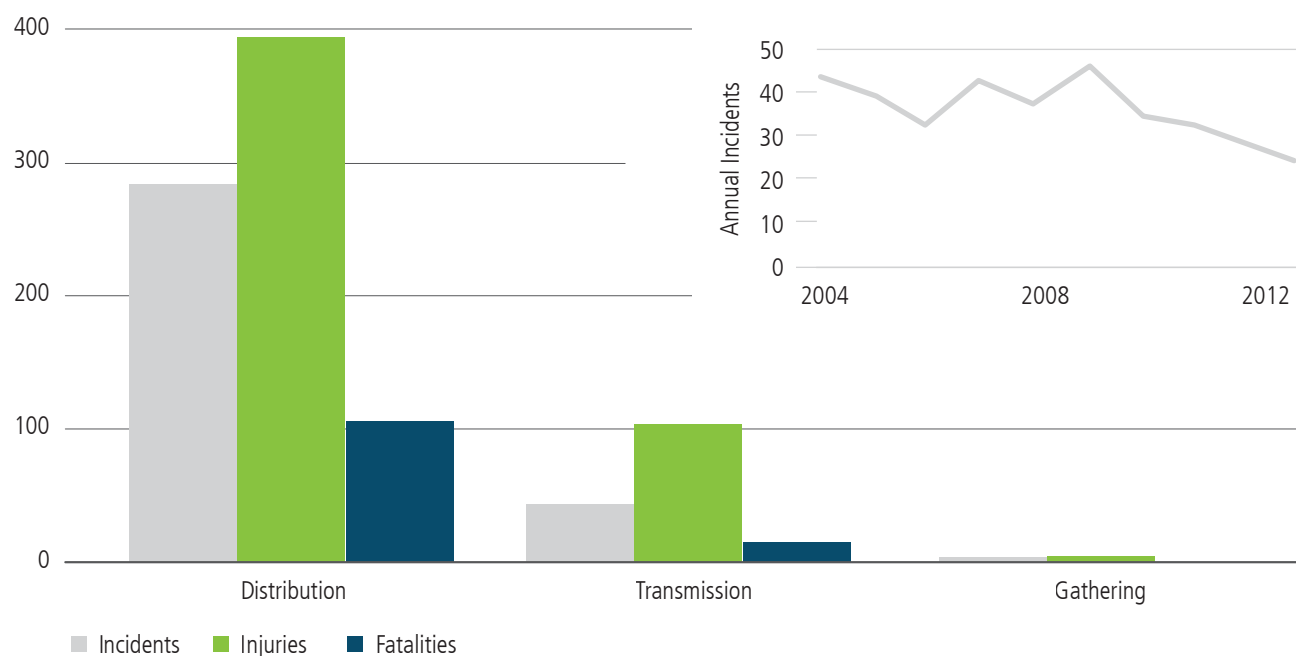
^{bn}This figure shows methane emissions reduction potential in 2018, assuming a market price for natural gas of \$4/Mcf (1,000 cubic feet) and a 10 percent discount rate.

Background on Natural Gas Pipeline Safety

Most safety incidents involving natural gas pipelines occur on the natural gas distribution system, as shown in Figure B-29. These incidents tend to occur in densely populated areas. Excavation damage is the leading cause of serious incidents along natural gas pipelines; although, significant and preventable contributors also include equipment failure, incorrect operation, and pipeline corrosion.¹⁸² Incidents are relatively infrequent, but increase as systems age. Overall, pipeline safety has been improving; over the past 20 years, there has been a general downward trend in recorded safety incidents (see Figure B-29).

Figure B-29. Safety Incidents, Injuries, and Fatalities Associated with U.S. Natural Gas Pipelines, 2004–2013^{183, 184}

Occurrences (total 2004–2013)



Incidents (grey), injuries (green), and fatalities (blue) associated with U.S. natural gas pipelines, totaled from 2004 through 2013. Note that only a small portion of gathering lines are subject to reporting requirements; therefore, data likely underrepresent the number of incidents that have occurred on gathering lines.

While natural gas transmission and gathering systems are critical to the functioning of the U.S. economy, the safety risk is concentrated in local distribution systems, which, though they tend to operate at relatively low pressures and volumes, are located in heavily built-up areas. Over the 20-year period of 1995–2014, local distribution system accidents accounted for 279 fatalities and more than 1,000 injuries, while transmission systems accounted for 42 fatalities and 174 injuries, or about one-seventh of the total. Over the 4-year period of 2011–2014, there has only been one single transmission-related fatality.

The 2010 natural gas transmission pipeline accident in San Bruno, California, which left 9 dead and more than 50 injured, has motivated a reexamination of gas transmission pipeline safety. The Obama Administration's Department of Transportation and PHMSA first responded to concerns about transmission pipeline safety by issuing a "call to action" on pipeline safety in 2011.¹⁸⁵ Congress also responded to the same concerns by passing the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. This act directed the Department of Transportation to reexamine many of its requirements, including the expansion of integrated management plans for transmission pipelines.¹⁸⁶ In addition, in 2011, the National Transportation Safety Board recommended that PHMSA require all operators of transmission and distribution natural gas pipelines to equip their pipeline monitoring systems with tools to assist in recognizing and pinpointing the location of leaks.¹⁸⁷

A recent study¹⁸⁸ by the National Transportation Safety Board investigated three major gas transmission pipeline accidents^{bo} to evaluate the need for safety improvements to the integrity management programs that are required by PHMSA in populated, high-consequence areas. The study found that integrity management requirements have reduced the rate of failures due to pipe welds, corrosion, and materials. However, pipeline incidents in high-consequence areas due to other factors increased between 2010 and 2013, and overall occurrence of gas transmission pipeline incidents in high-consequence areas has remained stable. Many types of basic data necessary for comprehensive probabilistic risk modeling are not currently available. The National Transportation Safety Board's recommendations to address the shortcomings identified in this report include more training and clearer protocols for pipeline inspectors, better quality spatial data on pipelines that can be more easily accessed, and improved coordination between industry groups and federal regulators.

Operators of transmission pipelines and gathering lines have fewer requirements than distribution lines to ensure pipeline integrity and safety through damage prevention programs, routine inspection, leak detection, and the development of integrity management plans.¹⁸⁹ While there are industry standards for certain routine practices—for example, for instrumentation, safety equipment, and metering—there are no comparable industry standards or industry-led systematic research program for external sensor-based leak detection.¹⁹⁰

PHMSA prepared an Advanced Notice of Proposed Rulemaking covering natural gas transmission and gathering lines in 2011, and has a Notice of Proposed Rulemaking in preparation, aimed at addressing post-San Bruno National Transportation Safety Board recommendations and other issues raised by recent pipeline safety experience.

Opportunities for Improving Pipeline Safety and Reducing Methane Emissions from Distribution Systems

Throughout natural gas infrastructure, there are a number of opportunities to reduce emissions while improving safety and further reducing risks to life and property. As discussed in the following section, identifying and reducing system leaks is a core strategy for achieving these goals.¹⁹¹

The most leak-prone distribution pipeline materials are cast iron and bare steel, accounting for approximately 9 percent of distribution pipes in the United States¹⁹² and resulting in roughly 30 percent of methane emissions from natural gas distribution systems.¹⁹³ Most regions of the country have some leak-prone distribution pipeline networks. Table B-8 presents the 10 states with the most miles of leak-prone distribution mains.^{bp} The magnitude of investment needed to replace all leak-prone distribution mains nationwide is more than \$270 billion.^{bq}

^{bo} Palm City, Florida (May 4, 2009); San Bruno, California (September 9, 2010); and Sissonville, West Virginia (December 11, 2012).

^{bp} Distribution mains are pipelines that serve as a common source of supply for more than one service line. Source: 49 CFR § 192.3. In: Pipeline and Hazardous Materials Safety Administration. "Glossary." www.phmsa.dot.gov/staticfiles/PHMSA/Pipeline/TQGlossary/Glossary.html#main. Accessed March 9, 2015. Generally, these are gas pipelines running underground along streets, connecting to service lines that run to individual buildings.

^{bq} The American Gas Association reports that the total cost of replacing all cast iron pipe in the United States is \$82,682,696,844 in 2011 dollars. According to PHMSA data, cast iron pipes represent approximately 30 percent of the total leak-prone pipe in the United States. Therefore, assuming other pipe replacement has similar costs, the total cost for replacement of all leak-prone pipe is roughly \$270 billion. Source: American Gas Association. "Managing the Reduction of the Nation's Cast Iron Inventory." 2013. www.aga.org/managing-reduction-nation%E2%80%99s-cast-iron-inventory. Accessed January 16, 2015.

Table B-8. 10 States with the Most Miles of At-Risk Distribution Mains¹⁹⁴

Rank	State	Leak Prone Iron Mains (mi)	Leak Prone Steel Mains (mi)	Total Leak Prone Mains (mi)	Total Leak Prone Mains (% of pipes in state)
1	PA	3,300	8,600	11,900	25%
2	NY	4,200	7,500	11,700	25%
3	OH	570	9,500	10,070	18%
4	CA	29	8,200	8,229	8%
5	NJ	4,900	2,200	7,100	21%
6	MA	3,600	2,600	6,200	30%
7	TX	820	5,000	5,820	6%
8	MI	3,000	2,300	5,300	9%
9	WV	13	3,000	3,013	29%
10	AL	1,200	820	2,020	7%

The 10 states with the most miles of at-risk natural gas mains contain 73 percent of the national total of at-risk mains, including 77 percent of the at-risk steel mains and 66 percent of the at-risk iron mains nationally. Of these 10 states, West Virginia is the only one without any kind of infrastructure modernization acceleration initiative.

Traditional public utility commission regulatory frameworks for pipeline operators do not ensure cost recovery for investments in system upgrades until approved by the public utility commission. Therefore, several states have adopted special trackers or surcharges to enable accelerated cost recovery for pipeline replacement. At present, 38 states have adopted mechanisms for infrastructure replacement cost recovery, which has greatly enabled the progress in cast iron pipeline replacement observed in recent years.¹⁹⁵ However, many of these programs have limitations, such as caps on the magnitude of investments eligible for cost recovery and/or on the size of associated rate increases. Pipeline replacement efforts have contributed to a 22-percent decrease in the amount of gas that leaks from distribution pipelines since 1990.¹⁹⁶ However, at current replacement rates, it will take several decades for many companies to replace these pipes.¹⁹⁷ Table B-9 shows replacement time frames for select at-risk distribution systems.

Table B-9. Expected At-Risk Replacement Horizons for Select Utilities¹⁹⁸

Utility Company	Service Territory	State	Forecasted Time Frame (years)	
Philadelphia Gas Works	Philadelphia, PA	PA		84
ConEd	New York, NY	NY		35
PECO	Greater Philadelphia, PA	PA		33
PSE&G	Newark, NJ	NJ		30
Pensacola Energy	Pensacola, FL	FL		30
Baltimore Gas Company	Baltimore, MD	MD		30
UGI	Rural Pennsylvania	PA		27
Consumers Energy	Detroit, MI	MI		25
DTE	Detroit, MI	MI		25
National Grid	New York, NY	NY		25
Dominion Hope Gas Co.	Ohio	OH		20
Yankee Gas Services Company	Rural Connecticut	CT		20
Peoples Gas	Chicago, IL	IL		20
National Grid - Niagra Mohawk	Rhode Island	RI		19
Peoples TWP	Southwestern Pennsylvania	PA		19
Peoples Natural Gas Co.	Southwestern Pennsylvania	PA		17
National Grid - Niagra Mohawk	Syracuse, NY	NY		16
Columbia Gas of Pennsylvania	Southwestern Pennsylvania	PA		15
Northern Utilities	Maine	ME		13
CenterPoint	Arkansas	AR		12

Projected pipeline replacement rates (from a select group of utilities) vary considerably and can range from about one decade to more than 80 years. Key factors affecting projected time frames include remaining miles of pipeline made of leak-prone materials (e.g., cast iron and unprotected steel) and the scale of existing replacement programs.

A challenge for accelerating replacement results from the potential rate impacts on low- and fixed-income households.¹⁹⁹ Of the estimated \$270 billion to replace leak-prone pipes, about \$45 billion, or 17 percent, of the cost would fall on low-income households (i.e., households below 150 percent of the poverty level). Furthermore, additional replacement efforts could be more cost effective and expeditious when state agencies and municipalities coordinate pipeline replacement with other public works projects (i.e., in conjunction with water and telecommunications modernization efforts). Therefore, pipeline replacement initiatives that provide rate relief to low-income consumers and more effectively address bureaucratic barriers may be more successful.

While most state programs have focused on pipe replacement, few states have initiated programs to reduce leaks from surface facilities, including meters and regulators at city gate stations. Natural gas losses from meters and regulators at “city gate” stations—facilities that connect long-distance interstate transmission pipelines to local distribution networks—account for 40 percent of methane emissions from distribution systems. A recent study found that, in cases where companies had invested in upgrades, emissions from city gate stations in 2013 declined to a fraction of emission levels measured at the same stations in 1992. Conversely, the one station that had not invested in upgrades

over this 20-year period saw a 40-percent increase in estimated emission levels, illustrating the environmental benefits of such investments.²⁰⁰ According to Natural Gas STAR, implementing a directed inspection and maintenance program is a proven and cost-effective way to detect, measure, prioritize, and repair equipment leaks to reduce methane emissions from distribution-stage meters and regulating equipment.²⁰¹ Additionally, it is estimated²⁰² that a directed inspection and maintenance program that includes quarterly leak detection and repair (LDAR), which requires little capital investment and could be scaled up quickly, could reduce emissions from city gate stations by 60 percent.

The combination of emissions from leak-prone cast iron and unprotected steel pipelines plus meters and regulators at “city gate” stations account for roughly 70 percent of total methane emissions from distribution facilities.²⁰³ Rate-mitigation programs could be designed in a variety of ways to meet the needs of the particular regulatory and utility environment. For example, offsetting rate increases with a phase-down period could help overcome concerns about rate increases and allow time to adopt new energy efficiency measures to reduce gas consumption and offset the cost of higher rates.

Policy and Regulatory Context for Reducing Emissions from Natural Gas Transmission, Storage, and Distribution

Both state and Federal entities play important regulatory roles with respect to three key aspects of natural gas infrastructure: (1) natural gas pipeline and distribution service and pipeline siting, (2) natural gas pipeline safety, and (3) air emissions associated with the oil and natural gas processing and transmission.^{br}

Economic Regulation and Siting. The Federal Energy Regulatory Commission has sole responsibility under the Natural Gas Act of 1938 for the siting of interstate natural gas pipelines and for regulating transmission and wholesale sales of natural gas in interstate commerce (Natural Gas Act § 7, 15 U.S.C. § 717c; *Id.* at § 4, 15 U.S.C. § 717f). State public utility commissions (or their equivalent) have jurisdiction over economic regulation of intrastate pipelines and distribution pipelines.

Safety. Pipeline safety laws provide the Department of Transportation with broad rulemaking authority to issue minimum safety standards for natural gas and hazardous liquid pipelines and pipeline facilities.^{bs} The Department of Transportation has delegated its responsibility to ensure the safe transportation and distribution of natural gas to the Pipeline and Hazardous Materials Safety Administration,^{bt} which has established minimum safety standards for nearly all natural gas pipelines.^{bu} The Pipeline Safety Act allows states to regulate, inspect, and enforce pipeline safety requirements for intrastate pipelines pursuant to a certification program. Through this delegation, states have primary inspection and enforcement authority over intrastate pipelines, including distribution lines.

Environmental Regulation. States are the primary regulators of many aspects of natural gas production activities and the distribution of natural gas. Since 2012, the Environmental Protection Agency has taken a series of steps to address air emissions from the oil and gas sector, working collaboratively with states and key stakeholders. For example, in 2012, the Environmental Protection Agency issued standards for volatile organic compounds from the oil and gas industry.

^{br} Quadrennial Energy Review Analysis: Paranhos, E. et al. “Controlling Methane Emissions in the Natural Gas Sector – A Review of Federal & State Regulatory Frameworks Governing Production, Processing, Transportation, and Distribution.” Joint Institute for Strategic Energy Analysis. NREL/TP-6A50-63416. April 2015. <http://energy.gov/epsa/qer-document-library>.

^{bs} 49 U.S.C. § 60102 et seq. Safety standards may apply “to the design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities.” *Id.* at § 60102(a)(2). See also Diamond 2013. Pipeline facilities include gas pipeline and hazardous liquid pipeline facilities, as well as rights of way, facilities, buildings, or equipment used in the transport or treating of gas during transportation. 49 U.S.C. § 60101(a).

^{bt} Diamond, et al. “Pipeline Safety: An Overview of the Legal Framework, the Regulation of Gas Gathering, and How Current and Future Regulation May Affect Producers.” Energy & Mineral Law Foundation. 2013.

^{bu} Exceptions include certain gathering lines located in rural areas operating at low pressures (the non-regulated gathering lines). PHMSA exercises jurisdiction over all interstate distribution and transmission pipelines and “regulated” gathering lines.

Policy and Regulatory Context for Reducing Emissions from Natural Gas Transmission, Storage, and Distribution (continued)

These standards, when fully implemented, are expected to annually reduce 190,000 tons to 290,000 tons of emissions of volatile organic compounds, which pose risks to public health and the environment.^{bv}

^{bv} Environmental Protection Agency. “Regulatory Impact Analysis; Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry.” 2012. http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf.

Federal pipeline safety law directs PHMSA to design safety standards to also protect the environment, consider environmental information when setting standards, and consider “the reasonably identifiable or estimated benefits expected to result from implementation or compliance with the standard” and “the reasonably identifiable or estimated costs expected to result from implementation or compliance with the standard.”²⁰⁴ These provisions authorize PHMSA to consider environmental information, such as the amount of methane leaked from pipelines and the social benefits and costs of standards designed to minimize leaks. Adopting this approach would increase the monetized benefits of stronger rules, regardless of whether the rule applies to distribution, transmission, or gathering pipeline infrastructure.

Transmission pipeline safety regulators and operators have also expressed mutual interest in demonstrating the effectiveness of In-Line Inspection methods for better risk evaluation and management of pipeline safety as an alternative to hydrostatic testing in the cases where safety can be verifiably maintained.²⁰⁵ Hydrostatic testing can result in substantial costs, occasional disruptions in service, and substantial emissions due to the routine evacuation of natural gas from pipelines prior to tests. Allowing alternatives to hydrostatic testing (including In-Line Inspection technologies), combined with research and development, could help to drive innovation in pipeline integrity testing technologies and eventually lead to improved safety and system reliability.

Greenhouse Gas Emissions and System Efficiency

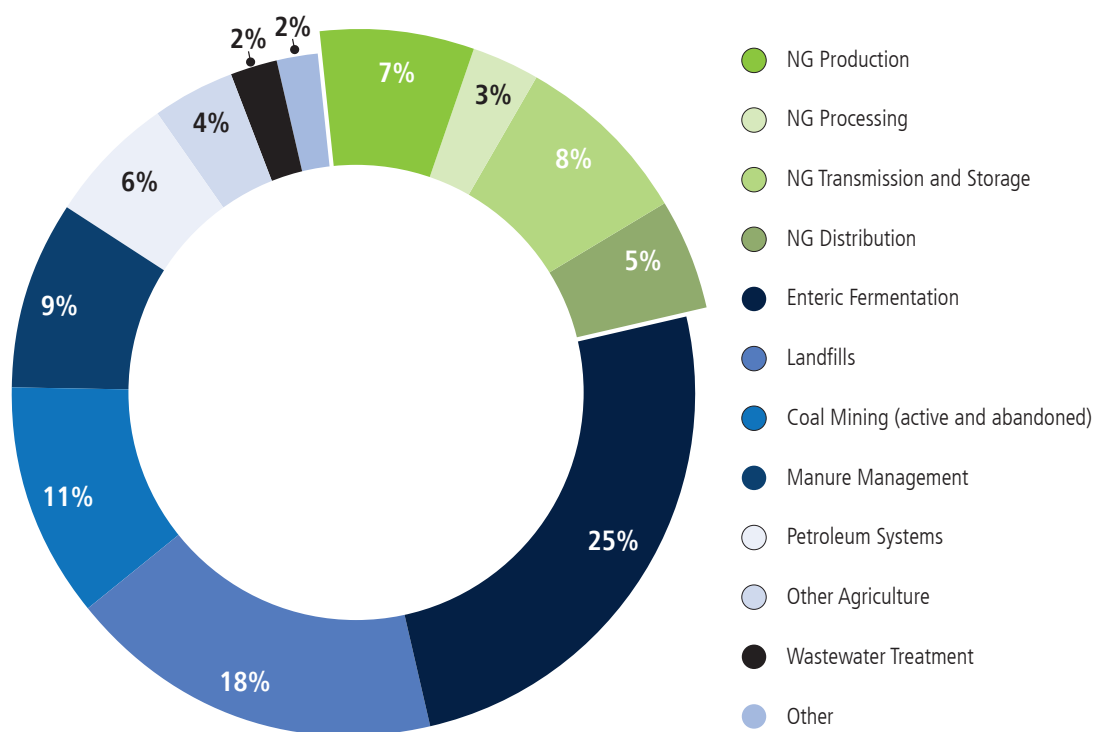
Increased domestic production and lower prices for natural gas have helped to significantly reduce carbon dioxide (CO₂) and other air pollution from the U.S. power sector. Emissions of methane from throughout the natural gas system have also been declining.²⁰⁶ These trends are encouraging because they highlight recent U.S. progress in addressing climate change. However, methane emissions from the processing and transmission segments has increased by 13 percent since 2005,²⁰⁷ and recent analyses by EIA²⁰⁸ and for the 2014 “U.S. Climate Action Report”²⁰⁹ project that CO₂ and methane emissions from natural gas systems will increase in the coming decades.

Methane is a potent GHG. Even with a relatively short atmospheric lifetime of 10 years to 12 years,²¹⁰ when integrated over 100 years, methane is more than 25 times more effective than CO₂ at trapping heat in the atmosphere.^{bw} The Environmental Protection Agency’s (EPA’s) national Greenhouse Gas Inventory (GHGI) estimates that methane contributes roughly 10 percent of total GHG emissions (on a CO₂-equivalent basis) from U.S. anthropogenic sources^{bx}—nearly one-quarter of which were emitted by natural gas systems (see Figure B-30).²¹¹

^{bw} Considering these impacts over such a period leads to what is called the Global Warming Potential (GWP) of a greenhouse gas. The 100-year GWP for methane from the Intergovernmental Panel on Climate Change Fourth Assessment Report is 25. A 20-year GWP can be used to measure the shorter-term impacts of methane emissions. GWPs compare GHGs by equating the warming potential of gases other than CO₂ to the equivalent amount of CO₂ emissions needed to achieve the same warming.

^{bx} Methane is assumed to have a global warming potential of 25, as currently used by EPA in a recently published GHG Reporting Program report, which is also consistent with the Intergovernmental Panel on Climate Change’s Fourth Assessment Report (2007).

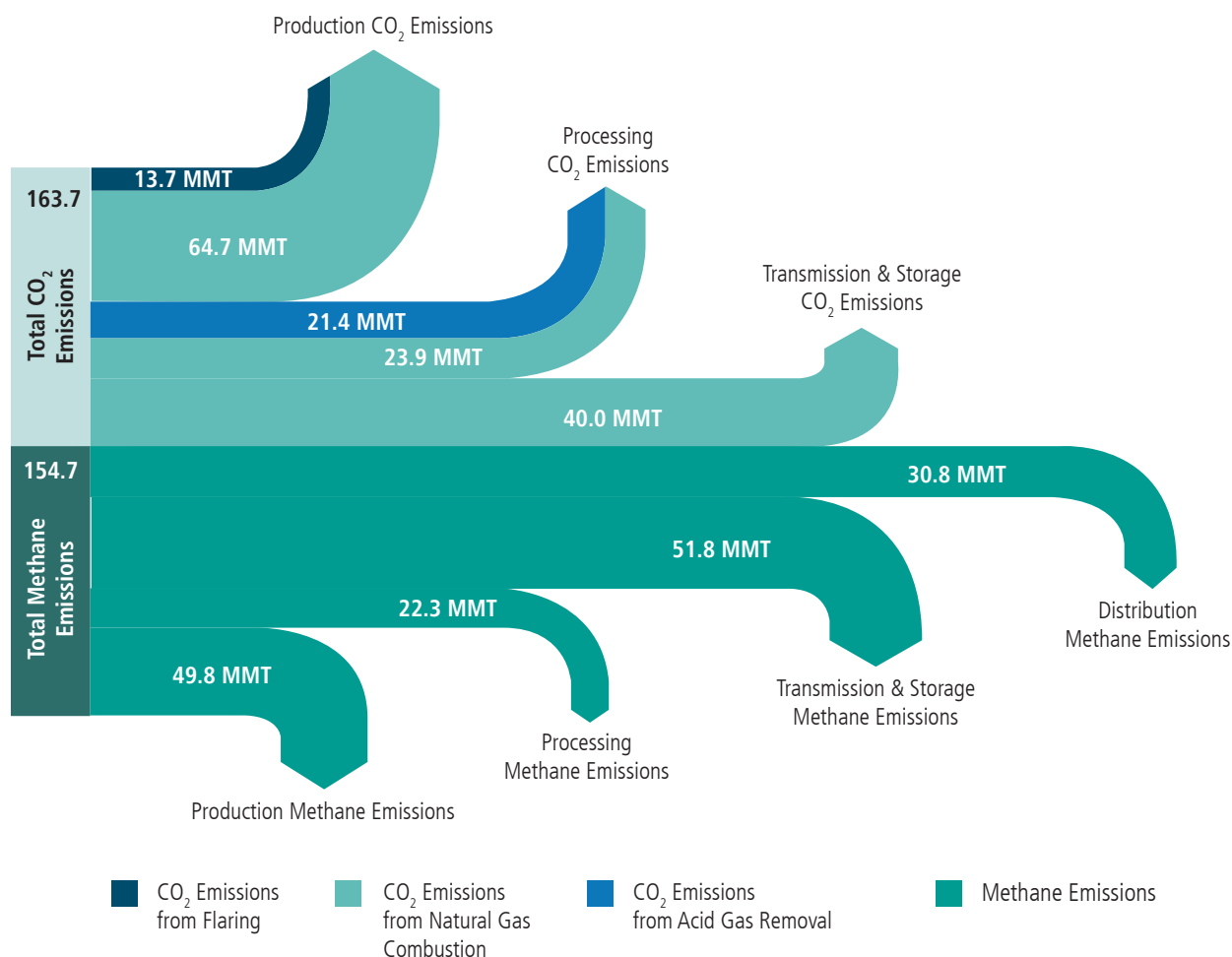
Figure B-30. Sources of U.S. Anthropogenic Methane Emissions in 2012, with Detailed View of Emissions from the Natural Gas Sector²¹²



Methane emissions from the natural gas sector (shown in grey and black, expanded from other sources) comprise nearly one-quarter of all anthropogenic methane emissions in the United States and are the second-largest category of anthropogenic methane emissions in the United States. Natural gas system emissions in scope for the QER from processing, transmission and storage, and distribution represent 16 percent of all U.S. methane emissions.

Pipeline quality natural gas is composed of more than 90 percent methane. As natural gas travels from underground reservoirs through pipelines, processing plants, and distribution networks, GHG emissions occur at each stage of natural gas infrastructure—from wellhead to customer meter. While 80 percent of GHG emissions from natural gas occur at the end-use stage (from combustion by consumers), significant methane and CO₂ emissions also occur throughout the natural gas system in almost equal amounts on a CO₂-equivalent basis.²¹³ Roughly 155 million metric tons CO₂ equivalent of methane was emitted in 2012 through routine venting, as well as inadvertent leakage.²¹⁴ Examples of routine “venting” include blowdowns (when gas is evacuated from a section of pipeline for the purpose of conducting tests), repairs, or maintenance. Natural gas also is vented by pneumatic devices, which operate natural gas-driven controllers and natural gas-driven pumps—both of which are used extensively throughout the oil and natural gas industry, emitting natural gas as a function of routine operation. Natural gas “leakage,” also commonly referred to as “fugitive emissions,” includes those emissions that occur inadvertently as a result of malfunctioning equipment (e.g., damaged seals, cracked pipelines). Also in 2012, a roughly equal amount of CO₂ (about 164 million metric tons CO₂ equivalent) was emitted throughout natural gas infrastructure, primarily from the combustion of natural gas that is used as a fuel, but also when non-hydrocarbon gases are removed during the processing stage, and from flaring. Figure B-31 shows these emissions in detail from the natural gas infrastructure; note that GHG emissions in scope for the QER include only those from processing, transmission, storage, and distribution segments.

Figure B-31. GHG Emissions from Natural Gas Production, Processing, Transmission, Storage, and Distribution²¹⁵



Both CO₂ (top of diagram) and methane (bottom of diagram) are emitted in roughly equal amounts from various sources and processes upstream of end-use consumers. Eighty percent of the GHG emissions from the natural gas system result from consumer end use of natural gas. However, these emissions are omitted from this figure to enable a more detailed picture of emissions from natural gas infrastructure.

The GHGI reports that the vast majority of methane emissions from natural gas processing, transmission, and storage segments are from leakage and venting by compressors and compressor engines. Distribution sector methane emissions mainly result from leakage by meters, regulators, and distribution pipelines. Older vintage distribution pipelines made of cast iron and unprotected steel are the leakiest types of distribution pipeline per mile. GHGI estimates that approximately 68 percent of methane emissions within the natural gas system originated from sources in the natural gas processing, transmission, storage, and distribution segments (see Figure B-31).

There are economic, environmental, and safety benefits associated with modernizing the natural gas TS&D system. Policies are needed to ensure that private companies can recover costs of such investments to improve safety and reduce emissions.²¹⁶ As shown in the marginal abatement cost curve in the beginning of this section (see Figure B-28), a number of actions to reduce losses of natural gas—and therefore methane—could have potential net cost savings if cost savings from recovered natural gas could be realized. Cost-effective options for reducing methane emissions from natural gas infrastructure include (1) changing operations and maintenance practices, (2) increasing LDAR, and (3) upgrading equipment.^{217, 218, 219} In the case where the full value of the recovered natural gas can be realized (see Figure B-28), the abatement opportunities with the largest cost

savings include LDAR and capturing vented gas, both mainly from the transmission and processing segments of the natural gas system. Downstream of production, across evaluated opportunities, there are 35 million metric tons of CO₂-equivalent emissions with potential net cost savings if the full value of the recovered natural gas could be realized.

As indicated from the marginal abatement cost curve in Figure B-28, identifying and repairing leaks (i.e., LDAR) is a critical aspect of natural gas infrastructure operations and maintenance—from safety, reliability, and environmental perspectives—but more low-cost technologies are needed to increase the ability to detect leaks. The leading Federal Government effort to advance methane-sensing technologies is the DOE Advanced Research Projects Agency-Energy \$30-million, 3-year program: Methane Observation Networks with Innovative Technology to Obtain Reductions. On December 16, 2014, the program announced²²⁰ support for 11 new projects that are each developing low-cost, highly sensitive systems that detect and measure methane associated with the production and transportation of oil and natural gas. An additional need is lower-cost technologies that can be utilized for continuous emissions monitoring in LDAR applications and for updating the GHGI.

Data from EIA²²¹ indicate that fuel use—and therefore CO₂ emissions—by natural gas processing and transmission^{by} increased by 35 percent between 2005 and 2013. As natural gas infrastructure continues to expand, the EIA projects that natural gas fuel use by TS&D will continue to increase in the coming decades,²²² leading to greater CO₂ and potentially other combustion-related air emissions from these facilities. Methane emissions from natural gas processing, transmission, and storage have increased by 13 percent from 2005 to 2012,²²³ which is slower than increases in fuel use because new infrastructure is less prone to leakage.

Therefore, in addition to improving emissions control technologies, an important opportunity for extracting the greatest value from natural gas is to improve the efficiency of its use in natural gas infrastructure. Large energy efficiency gains seem possible from improving the efficiency of existing compressor systems, which currently account for at least 85 percent of energy-related CO₂ emissions from natural gas processing and transmission.²²⁴ What often limits system efficiency is the need for flexibility over a wide range of operating conditions (pressures and/or flow rates). As a result, compressors often operate below their design efficiency point. For this reason, incentivizing compressor and prime mover designs with higher operating efficiencies across a wide range of flow rates and flow conditions will likely be needed. Additional policy actions for improvements in the energy efficiency of the natural gas infrastructure are currently underway at DOE, such as energy efficiency standards for natural gas compressors and research, development, demonstration, and deployment initiatives to increase the energy efficiency (technical potential and operational efficiency) of new and currently in-place equipment.

Beyond compressors and prime movers, additional opportunities for increasing energy efficiency include pipeline operations, sizing, layout, cleaning, and interior coatings, as well as opportunities for waste heat recovery. While the greatest opportunities for efficiency improvement lie in new systems, options do exist for improving the efficiency of existing systems as well.²²⁵

Improving the Greenhouse Gas Inventory

EPA leads the development of the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks (i.e., GHGI)—the official U.S. estimate submitted to the United Nations Framework Convention on Climate Change. The GHGI tracks the national trend in GHG emissions and removals back to 1990 and contains total U.S. emissions by source, economic sector, and GHG. The GHGI includes annual national estimates of emissions from the natural gas system.²²⁶

^{by} This includes U.S. natural gas “plant fuel consumption” and “pipeline and distribution use.”

In addition, EPA collects detailed emissions data from the largest GHG emitting facilities in the United States through the Greenhouse Gas Reporting Program (GHGRP). EPA has collected data from large facilities (including processing plants, transmission stations, and field production at the basin level) in the petroleum and natural gas sectors since reporting year 2011.

EPA has used data from GHGRP to update GHGI estimates for several key sources and will continue to do so as additional data become available through GHGRP.

Both the GHGI and the GHGRP have been used to inform government policies and priorities for GHG emissions reductions efforts, such as the President's "Climate Action Plan."²²⁷

The White House's Strategy to Reduce Methane Emissions recommends further enhancing emissions data and addressing data gaps to ensure high-quality data reporting.²²⁸ Though EPA annually updates the GHGI, routinely incorporating new information, much of the underlying measurement data used to construct the GHGI estimates for oil and gas systems was collected in the mid-1990s²²⁹ and does not reflect all of the changes that have occurred to the U.S. natural gas system since that time, such as evolving regional differences.^{bz}

There are ongoing efforts to collect updated data that could be used to update emissions estimates, which are being privately and federally funded and carried out by multiple researchers, including a large effort led by the Environmental Defense Fund.²³⁰ In addition, EPA is collecting data on these emission sources through its GHGRP, which is being used to update the GHGI. However, additional Federal and private funding is needed for efforts that would allow for further updates to the GHGI, such as additional measurements and other data collection to update activity counts and emission factors, among other priorities for updating the GHGI. Most studies of methane emissions in the United States are not currently coordinated across research groups, which have varying research priorities and differing methodologies.^{ca} Federal coordination, and communication of priorities and needs, can help improve the relevance of research efforts to update the GHGI and help ensure that this research area moves forward in a more systematic, efficient, and complete fashion.

Improving Air Quality

The primary concern with respect to air quality and pollution from natural gas facilities is volatile organic compounds from production facilities (prior to processing, which removes non-hydrocarbon gases) and nitrogen oxides emissions from compressor stations throughout natural gas systems. Reducing these emissions is important for improving air quality, particularly ground-level ozone. While overall emissions have been declining for decades, trends are inconsistent across different sectors. For example, though still only 5 percent of the national total, nitrogen oxides emissions from the oil and natural gas sectors^{cb} have increased by roughly 94 percent between 2005 and 2011.²³¹ This is particularly striking, as EPA trends data²³² show that vehicle and power plant emissions have declined considerably.^{cc}

^{bz} One example of a study that illustrates this point is Allen et al. "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers." 2014. Environmental Science & Technology. pubs.acs.org/doi/abs/10.1021/es5040156. Accessed December 16, 2014.

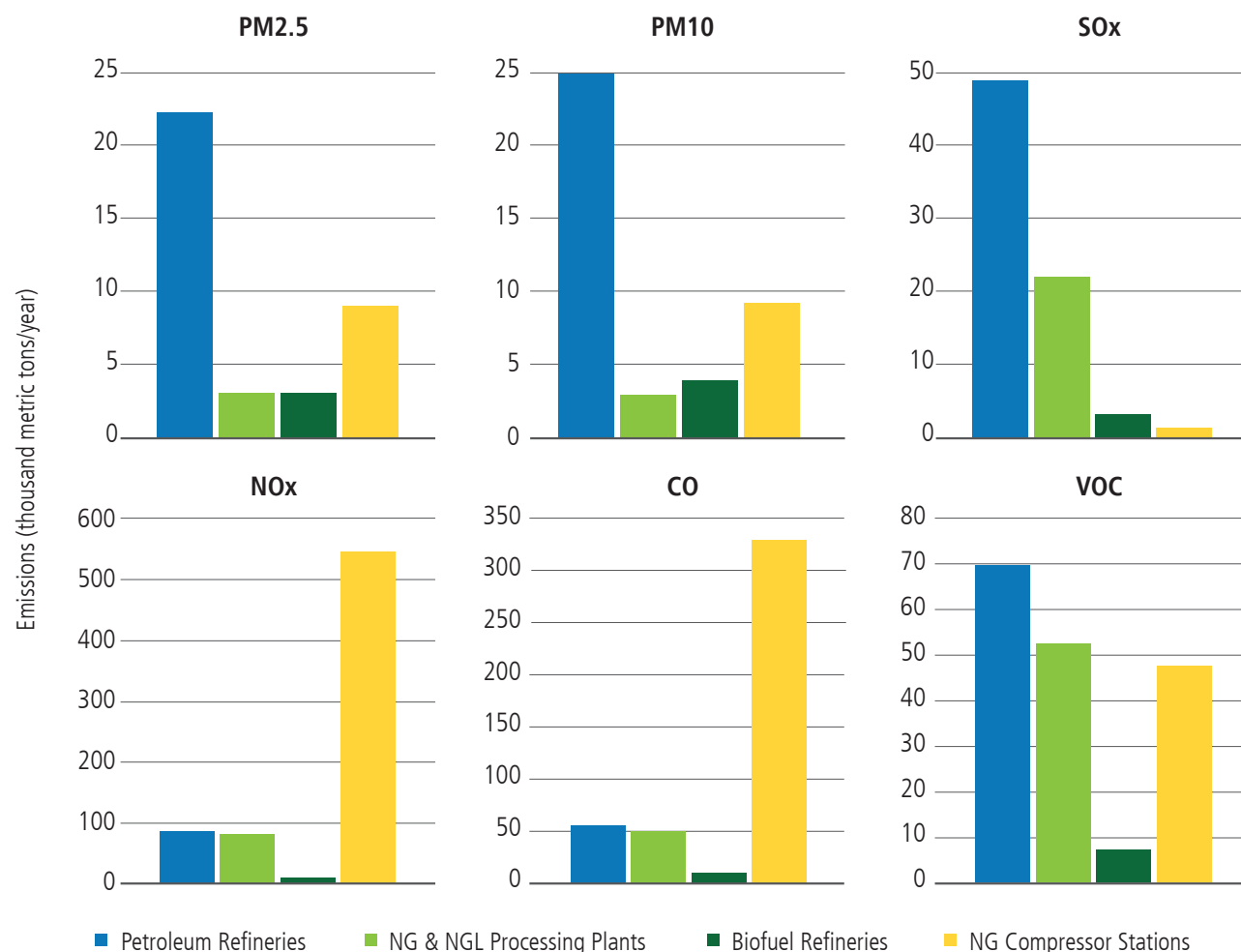
^{ca} For example, the following study provides a summary of many recent studies of methane emissions from natural gas infrastructure: Brandt, A. et al. "Methane Leaks from North American Natural Gas Systems." Science. 343(6172). p. 733–735.

^{cb} This is based on EPA National Emissions Inventory estimates of nitrogen oxides emissions for the combination of two sectors: "petroleum and related industries" and "storage and transport;" with roughly half of these emissions coming from natural gas compressors.

^{cc} EPA estimates that nitrogen oxides emissions from highway vehicles have declined by 50 percent since 1990, while electric power sector nitrogen oxides emissions are more than 70 percent lower than 1990 levels.

Among the stationary emission source categories that are in scope for the QER, which is only a small proportion of total stationary sources, natural gas compressors are the biggest total emitters of ozone precursors (see Figure B-32). Total capacity for natural gas compression is also projected to grow significantly in the coming decades,²³³ which likely will lead to greater CO₂ and other combustion-related air emissions from natural gas infrastructure. Improving the efficiency and implementing technologies that reduce criteria air pollutant emissions of compressors operating along natural gas pipelines will be important to reducing GHGs and improving air quality in the future.

Figure B-32. Criteria Air Emissions from Stationary TS&D Facilities in 2011 (metric tons/year)^{234, cd}



Natural gas infrastructure is a major source of nitrogen oxides and carbon monoxide, primarily due to emissions from natural gas compressors in the transmission, gathering, and boosting segments of natural gas infrastructure. Nitrogen oxides emissions shown here for refineries and natural gas processing and compression accounted for roughly 30 percent of total nitrogen oxides emissions from all industrial processes and industrial fuel combustion in 2011.

^{cd} Air emissions from each source category were drawn from the EPA's National Emissions Inventory as follows: "Petroleum Refineries" (NAICS 324110); "Natural Gas and Natural Gas Liquid Processing Plants" (NAICS 211112); "Biofuel Refineries" (NAICS 325193); and "NG Compressors" (includes emissions from all facilities listed under Pipeline Transport of Natural Gas (NAICS 486210); plus compressor station facilities listed under Natural Gas Distribution (NAICS 221210); plus county total nonpoint compressor engines (source classification codes 2310020600, 23100211(01,02,03), 23100212(01,02,03), 23100213(01,02,03), and 23100214(01,02,03)).

Interagency Methane Strategy

As directed by President Obama in his “Climate Action Plan,” several Federal agencies are contributing to the Strategy to Reduce Methane Emissions, which was formally announced by the White House in March 2014. Central components of the strategy are to assess current emissions data and address data gaps, identify technologies and best practices for reducing emissions, and identify existing authorities and incentive-based opportunities for reducing methane emissions.

Administration Activities and Plans to Reduce Greenhouse Gas Emissions from Transmission, Storage, and Distribution Infrastructures

Building on the 2014 interagency Strategy to Reduce Methane Emissions, in January 2015, the President announced a national goal to reduce methane emissions from the oil and gas sector 40 percent to 45 percent from 2012 levels by 2025, as well as a set of actions to put the United States on a path to achieve this ambitious goal. These goals include the following:

Common-sense standards for methane emissions from new and modified sources. The Environmental Protection Agency (EPA) will initiate a rulemaking effort to set standards for methane and volatile organic compound emissions from new and modified oil and gas production sources and natural gas processing and transmission sources. EPA will issue a proposed rule in the summer of 2015, and a final rule will follow in 2016.

New guidelines to reduce volatile organic compounds. EPA will develop new guidelines to assist states in reducing ozone-forming pollutants from existing oil and gas systems in areas that do not meet the ozone health standard and in states in the Ozone Transport Region—an added benefit will be methane emissions reductions.

Enhancing leak detection and emissions reporting. EPA will continue to promote transparency and accountability for existing sources by strengthening its Greenhouse Gas Reporting Program to require reporting in all segments of the industry. In addition to finalizing updates to the program, by the end of 2015, EPA will explore potential regulatory opportunities for applying remote-sensing technologies and other innovations in measurement and monitoring technology to further improve the identification and quantification of emissions and improve the overall accuracy and transparency of reported data in a cost-effective manner.

Leading by example on public lands. The Department of the Interior’s Bureau of Land Management will update decades-old standards to reduce wasteful venting, flaring, and leaks of natural gas—primarily methane—from oil and gas wells. These standards, to be proposed in the spring of 2015, will address both new and existing oil and gas wells on public lands.

Reducing methane emissions while improving pipeline safety. The Department of Transportation’s Pipeline and Hazardous Materials Safety Administration will propose natural gas pipeline safety standards in 2015. While the standards will focus on safety, they are expected to lower methane emissions as well.

Modernizing natural gas transmission and distribution infrastructure. Following on its methane roundtables, the Department of Energy will continue to take steps to encourage reduced greenhouse gas emissions, including the following:

- Issuing energy efficiency standards for natural gas and air compressors
- Advancing research and development to bring down the cost of detecting leaks
- Implementing an Advanced Natural Gas System Manufacturing Research and Development Initiative
- Partnering with the National Association of Regulatory Utility Commissioners to help modernize natural gas distribution infrastructure
- Providing loan guarantees for new methane reduction technologies
- Developing a clearinghouse of information on effective technologies, policies, and strategies.

Industry actions to reduce methane emissions. Several voluntary industry efforts to address these sources are underway, including EPA’s plans to expand on the successful Natural Gas STAR Program by launching a new partnership in collaboration with key stakeholders later in 2015. EPA will work with the Department of Energy, the Department of Transportation, and leading companies—individually and through broader initiatives such as the One Future Initiative and the Downstream Initiative—to develop and verify robust commitments to reduce methane emissions.

Interagency Methane Strategy (continued)

Other Federal actions. The Federal Energy Regulatory Commission has issued a policy statement that will allow interstate natural gas pipelines to recover certain investments made to modernize pipeline system infrastructure in a manner that enhances system reliability, safety, and regulatory compliance. Additionally, in December 2014, the Council on Environmental Quality released revised draft guidance for public comment that describes how Federal departments and agencies should consider greenhouse gas emissions and climate change in their National Environmental Policy Act reviews.

ENDNOTES

1. Quadrennial Energy Review Analysis: BENTEK Energy. “The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments.” 2014. <http://energy.gov/epsa/qer-document-library>.
2. Energy Information Administration. “Glossary: Natural Gas.” <http://www.eia.gov/tools/glossary/?id=natural%20gas>. Accessed October 10, 2014.
3. Canadian Association of Petroleum Producers. “Conventional & Unconventional Natural Gas.” <http://www.capp.ca/canadaIndustry/naturalGas/Conventional-Unconventional/Pages/default.aspx>.
4. International Energy Agency. “FAQs: Natural gas.” 2014. <http://www.iea.org/aboutus/faqs/gas/>. Accessed October 20, 2014.
5. Department of Energy, Office of Energy Policy and Systems Analysis. Energy Information Administration data. 2015.
6. ICF International. “North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance.” INGAA Foundation, Inc. 2014.
7. IHS. “Oil & Natural Gas Transportation & Storage Infrastructure: Status, Trends, & Economic Benefits.” American Petroleum Institute. December 2013.
8. Energy Information Administration. “Monthly Dry Shale Gas Production.” Natural Gas Weekly Update. <http://www.eia.gov/naturalgas/weekly/>.
9. Energy Information Administration. “Natural Gas Gross Withdrawals and Production.” http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm.
10. Energy Information Administration. “Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays.” 2011.
11. Energy Information Administration. “Haynesville Surpasses Barnett as the Nation’s Leading Shale Play.” Today in Energy. March 18, 2011. <http://www.eia.gov/todayinenergy/detail.cfm?id=570>.
12. Sieminski, A. “Outlook for U.S. shale oil and gas.” Presentation for Argus Americas Crude Summit. Energy Information Administration. 2014.
13. Quadrennial Energy Review Analysis: BENTEK Energy. “The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments.” 2014. <http://energy.gov/epsa/qer-document-library>.
14. Energy Information Administration. “Short-Term Energy Outlook 2014.” July 8, 2014. <http://www.eia.gov/forecasts/steo/>.
15. Quadrennial Energy Review Analysis: BENTEK Energy. “The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments.” 2014. <http://energy.gov/epsa/qer-document-library>.
16. Quadrennial Energy Review Analysis: BENTEK Energy. “The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments.” 2014. <http://energy.gov/epsa/qer-document-library>.
17. Energy Information Administration. “Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays.” July 2011. <http://www.eia.gov/analysis/studies/usshalegas/>.
18. Energy Information Administration. “Natural Gas Monthly.” December 12, 2013. http://www.eia.gov/naturalgas/monthly/archive/2013/2013_11/ngm_2013_11.cfm. Accessed October 16, 2014.
19. Energy Information Administration. “Natural Gas: Natural Gas Weekly Update.” July 23, 2014. <http://www.eia.gov/naturalgas/weekly/>. Accessed October 16, 2014.
20. Energy Information Administration. “Natural Gas Monthly.” December 12, 2013. http://www.eia.gov/naturalgas/monthly/archive/2013/2013_11/ngm_2013_11.cfm. Accessed October 16, 2014.
21. Energy Information Administration. “Short-Term Energy and Winter Fuels Outlook 2014.” July 8, 2014. <http://www.eia.gov/forecasts/steo>.

22. Energy Information Administration. "Natural Gas Summary." June 30, 2014. http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_m.htm.
23. Quadrennial Energy Review Analysis: BENTEK Energy. "The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments." 2014. <http://energy.gov/epsa/qer-document-library>.
24. Energy Information Administration. "Annual Energy Outlook 2014: Market Trends: Natural Gas." http://www.eia.gov/forecasts/aeo/MT_naturalgas.cfm#ind_natgas.
25. Quadrennial Energy Review Analysis: BENTEK Energy. "The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments." 2014. <http://energy.gov/epsa/qer-document-library>.
26. Quadrennial Energy Review Analysis: BENTEK Energy. "The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments." 2014. <http://energy.gov/epsa/qer-document-library>.
27. Energy Information Administration. "Electricity Data Browser." Net generation for all sectors, annual. 2014.
28. Energy Information Administration. "Electricity Data Browser." Net generation for natural gas, annual; net generation from natural gas by state by sector. <http://www.eia.gov/electricity/data/browser/>. Accessed February 5, 2015.
29. Energy Information Administration. "Half of power plant capacity additions in 2013 came from natural gas." Today in Energy. April 8, 2014. <http://www.eia.gov/todayinenergy/detail.cfm?id=15751>. Accessed October 20, 2014.
30. Tobin, J. "Expansion and Change on the U.S. Natural Gas Pipeline Network – 2002." Natural Gas Analysis Publications 2002. May 12, 2003. http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2003/Pipenet03/pipenet03.html. Accessed October 20, 2014.
31. Energy Information Administration. "Natural gas, solar, and wind lead power plant capacity additions in first-half." Today in Energy. September 9, 2014. <http://www.eia.gov/todayinenergy/detail.cfm?id=17891>.
32. American Gas Association. "About Natural Gas: How to Measure Natural Gas." <http://www.aga.org/KC/ABOUTNATURALGAS/ADDITIONAL/Pages/HowtoMeasureNaturalGas.aspx>. Accessed October 20, 2014.
33. Energy Information Administration. "FAQ: How much coal, natural gas, or petroleum is used to generate a kilowatthour of electricity?" January 15, 2014. <http://www.eia.gov/tools/faqs/faq.cfm?id=667&t=2>. Accessed October 20, 2014.
34. Quadrennial Energy Review Analysis: BENTEK Energy. "The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments." 2014. <http://energy.gov/epsa/qer-document-library>.
35. Quadrennial Energy Review Analysis: BENTEK Energy. "The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments." 2014. <http://energy.gov/epsa/qer-document-library>.
36. Department of Energy, Office of Energy Policy and Systems Analysis. Energy Information Administration data. 2015.
37. Quadrennial Energy Review Analysis: Department of Energy, Office of Energy Policy and Systems Analysis. "Natural Gas Infrastructure Implications of Increased Demand from the Electric Sector." February 2015. <http://energy.gov/epsa/qer-document-library>.
38. Quadrennial Energy Review Analysis: BENTEK Energy. "The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments." 2014. <http://energy.gov/epsa/qer-document-library>.
39. Energy Information Administration. "Natural Gas 2014: Henry Hub Natural Gas Spot Price." October 8, 2014. <http://www.eia.gov/dnav/ng/hist/rngwhhdA.htm>. Accessed October 10, 2014.
40. Energy Information Administration. "Natural Gas 2014: Henry Hub Natural Gas Spot Price." October 8, 2014. <http://www.eia.gov/dnav/ng/hist/rngwhhdA.htm>. Accessed October 10, 2014.
41. Department of Energy, Office of Energy Policy and Systems Analysis. Intercontinental Exchange data. 2015.
42. Energy Information Administration. "Natural Gas Annual 2004." December 2005. <http://www.eia.gov/naturalgas/annual/archive/2004/pdf/nga04.pdf>.

43. Energy Information Administration. "Average wholesale natural gas prices fell 31% in 2012." Today in Energy. January 8, 2013. <http://www.eia.gov/todayinenergy/detail.cfm?id=9490>. Accessed October 20, 2014.
44. Energy Information Administration. "Natural gas spot prices near 10-year lows amid warm weather and robust supplies." Today in Energy. February 1, 2012. http://www.eia.gov/todayinenergy/detail.cfm?id=4810#tabs_NatGasPrices-2. Accessed October 20, 2014.
45. Serreze, M. "What is the polar vortex? Icelights: Your Burning Questions About Ice & Climate." January 10, 2014. <http://nsidc.org/icelights/2014/01/10/what-is-a-polar-vortex/>. Accessed October 20, 2014.
46. Energy Information Administration. "Record Winter Withdrawals Create Summer Storage Challenges." June 12, 2014. <http://beta.eia.gov/naturalgas/review/winterlookback/2013/>. Accessed October 20, 2014.
47. Quadrennial Energy Review Analysis: INTEK Inc. "United States Fuel Resiliency: Part I – US Fuels Supply Infrastructure (Vol 1–3)." September 2014. <http://energy.gov/epsa/qer-document-library>.
48. Department of Energy, Office of Energy Policy and Systems Analysis. Ventyx data. 2015.
49. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Fact Sheet: Natural Gas Processing Plants." <http://primis.phmsa.dot.gov/comm/factsheets/fsnaturalgasprocessingplants.htm>. Accessed July 30, 2014.
50. Energy Information Administration. "Natural Gas Processing: The Crucial Link between Natural Gas Production and Its Transportation to Market." January 2006. http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2006/ngprocess/ngprocess.pdf.
51. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Fact Sheet: Natural Gas Processing Plants." <http://primis.phmsa.dot.gov/comm/factsheets/fsnaturalgasprocessingplants.htm>. Accessed July 30, 2014.
52. IHS. "America's New Energy Future: The Unconventional Oil & Gas Revolution and the US Economy." 2013.
53. Energy Information Administration. "Natural Gas Annual Respondent Query System: 757 Processing Capacity." October 2012. http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP9&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compид=&f_fullscreen.
54. Energy Information Administration. "Natural Gas Annual Respondent Query System: 757 Processing Capacity." October 2012. http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP9&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compид=&f_fullscreen.
55. Energy Information Administration. "Natural Gas Annual 2012." December 2013. <http://www.eia.gov/naturalgas/annual/pdf/nga12.pdf>.
56. Energy Information Administration. "Natural Gas: Natural Gas Processing Plants in the United States: 2010 Update." June 17, 2011. http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngpps2009/overview.cfm. Accessed October 20, 2014.
57. Energy Information Administration. "Natural Gas Annual 2012." December 2013. <http://www.eia.gov/naturalgas/annual/pdf/nga12.pdf>.
58. Energy Information Administration. "Natural Gas Annual 2013." October 2014. <http://www.eia.gov/naturalgas/annual/pdf/nga13.pdf>.
59. Quadrennial Energy Review Analysis: BENTEK Energy. "The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments." 2014. <http://energy.gov/epsa/qer-document-library>.
60. Quadrennial Energy Review Analysis: BENTEK Energy. "The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments." 2014. <http://energy.gov/epsa/qer-document-library>.
61. Energy Information Administration. "High value of liquids drives U.S. producers to target wet natural gas resources." Today in Energy. May 8, 2014. <http://www.eia.gov/todayinenergy/detail.cfm?id=16191>.

62. Quadrennial Energy Review Analysis: BENTEK Energy. “The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments.” 2014. <http://energy.gov/epsa/qer-document-library>.
63. IHS. “Oil & Natural Gas Transportation & Storage Infrastructure: Status, Trends, & Economic Benefits.” American Petroleum Institute. December 2013.
64. ICF International. “North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance.” Interstate Natural Gas Association of America. March 2013.
65. North Dakota Industrial Commission. “Order No. 24665.” July 2014.
66. Quadrennial Energy Review Analysis: BENTEK Energy. “The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments.” 2014. <http://energy.gov/epsa/qer-document-library>.
67. Federal Regulatory Commission. “Current State of and Issues Concerning: Underground Natural Gas Storage.” Docket No. AD04-11-000. September 30, 2004. <http://www.ferc.gov/EventCalendar/Files/20041020081349-final-gs-report.pdf>. Accessed February 2, 2014.
68. Federal Regulatory Commission. “Natural Gas Storage - Storage Fields.” February 1, 2011. <https://www.ferc.gov/industries/gas/indus-act/storage/fields.asp>. Accessed January 28, 2015.
69. Energy Information Administration. “Underground Natural Gas Storage.” http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/undrgrnd_storage.html. Accessed July 2014.
70. Argonne National Laboratory. “Salt Caverns and Their Use for Disposal of Oil Field Wastes.” The National Petroleum Technology Office. 1999. <http://web.evs.anl.gov/saltcaverns/doc/SaltCavbroch.pdf>. Accessed January 28, 2015.
71. Energy Information Administration. “The Basics of Underground Natural Gas Storage.” August 2004. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/storagebasics/storagebasics.html.
72. Energy Information Administration. “191 Field Level Storage Data (Annual): 2012.” Natural Gas Annual Respondent Query System (EIA-191 data through 2013). April 2014. http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP7&f_sortby=ACI&f_items=&f_year_start=2012&f_year_end=2012&f_show_compid=Name&f_fullscreen.
73. Energy Information Administration. “Underground Natural Gas Storage Capacity.” July 31, 2014. http://www.eia.gov/dnav/ng/ng_stor_cap_a_EPG0_SA1_Mmcf_a.htm.
74. Energy Information Administration. “Monthly Underground Gas Storage Report.” Form EIA-191M. October 31, 2014 (data from 2013).
75. Quadrennial Energy Review Analysis: BENTEK Energy. “The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments.” 2014. <http://energy.gov/epsa/qer-document-library>.
76. Quadrennial Energy Review Analysis: BENTEK Energy. “The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments.” 2014. <http://energy.gov/epsa/qer-document-library>.
77. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. “Liquefied Natural Gas (LNG) in the U.S.” <https://primis.phmsa.dot.gov/comm/lng.htm>. Accessed January 28, 2015.
78. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. “Distribution, Transmission & Gathering, LNG, and Liquid Annual Data.” <http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnnextfmt=print>. Accessed September 8, 2014.
79. Federal Energy Regulatory Commission. “Statement of Chairman Joseph T. Kelliher on Gas Storage Pricing Reform.” Docket No. RM05-23-000. December 15, 2005.
80. Department of Energy, Office of Energy Policy and Systems Analysis. Energy Information Administration data. 2015.
81. Department of Energy, Office of Energy Policy and Systems Analysis. Energy Information Administration data. 2015.
82. Quadrennial Energy Review Analysis: BENTEK Energy. “The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments.” 2014. <http://energy.gov/epsa/qer-document-library>.

83. Quadrennial Energy Review Analysis: BENTEK Energy. “The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments.” 2014. <http://energy.gov/epsa/qer-document-library>.
84. Energy Information Administration. “Macroeconomic Impacts of LNG Exports from the United States.” 2013. http://energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf.
85. Department of Energy. “Liquefied Natural Gas.” <http://energy.gov/fe/science-innovation/oil-gas/liquefied-natural-gas>. Accessed August 1, 2014.
86. Excelerate Energy. “Excelerate Energy to Retire Its Gulf Gateway Deepwater Port.” April 13, 2011. <http://excelerateenergy.com/excelerate-energy-retire-gulf-gateway-deepwater-port/>.
87. Excelerate Energy. “Excelerate Energy to Retire Its Gulf Gateway Deepwater Port.” April 13, 2011. <http://excelerateenergy.com/excelerate-energy-retire-gulf-gateway-deepwater-port/>.
88. Foss, M.M. “LNG Safety and Security.” Center for Energy Economics. June 2012. http://www.beg.utexas.edu/energyecon/LNG_Safety_and_Security_Update_2012.pdf.
89. Energy Information Administration. “U.S. Natural Gas Imports (Million Cubic Feet).” 2014.
90. Energy Information Administration. “Natural Gas 2014: U.S. Natural Gas Imports by Point of Entry.” September 20, 2014. http://www.eia.gov/dnav/ng/ng_move_poe1_a_EPG0_IML_Mmcf_a.htm. Accessed October 20, 2014.
91. Energy Information Administration. “Natural Gas Annual 2012.” December 2013. <http://www.eia.gov/naturalgas/annual/pdf/nga12.pdf>.
92. Energy Information Administration. “Natural Gas 2014: U.S. Natural Gas Imports & Exports 2013.” May 28, 2014. <http://www.eia.gov/naturalgas/importsexports/annual>. Accessed October 20, 2014.
93. Energy Information Administration. “Natural Gas 2014: Imports, exports, and re-exports by country.” May 28, 2014. <http://www.eia.gov/naturalgas/importsexports/annual/#tabs-supply-2>. Accessed October 20, 2014.
94. Ailworth, E. “U.S. Natural-Gas Exports Fuel Mexican Manufacturing Boom.” Wall Street Journal. September 7, 2014. <http://www.wsj.com/articles/u-s-natural-gas-exports-fuel-mexican-manufacturing-boom-1410132721>.
95. Energy Information Administration. “Dollar value of natural gas net imports has declined dramatically in recent years.” Today in Energy. February 26, 2014. <http://www.eia.gov/todayinenergy/detail.cfm?id=15171>. Accessed October 20, 2014.
96. Department of Energy, Office of Energy Policy and Systems Analysis. Ventyx data. 2015.
97. Energy Information Administration. “U.S. Liquefied Natural Gas Imports.” <http://www.eia.gov/dnav/ng/hist/n9103us2A.htm>.
98. Quadrennial Energy Review Analysis: INTEK Inc. “United States Fuel Resiliency: Part I – US Fuels Supply Infrastructure (Vol 1–3).” September 2014. <http://energy.gov/epsa/qer-document-library>.
99. Yepez-Garcia, R.A. and J. Dana. “Mitigating Vulnerability to High and Volatile Oil Prices, Power Sector Experience in Latin American and the Caribbean.” p. 30. The World Bank. 2012.
100. Catalia Strategic Advisors. “Natural Gas in the Caribbean—Feasibility Study.” Prepared for the Inter-American Development Bank. August 10, 2014. <http://www.iadb.org/en/projects/project-description-title,1303.html?id=RG-T2243#doc>.
101. Catalia Strategic Advisors. “Natural Gas in the Caribbean—Feasibility Study.” Prepared for the Inter-American Development Bank. August 10, 2014. <http://www.iadb.org/en/projects/project-description-title,1303.html?id=RG-T2243#doc>.
102. Energy Information Administration. “Deliverability on the Interstate Natural Gas Pipeline System.” May 1998. http://ftp.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/deliverability/pdf/deliver.pdf.

103. National Conference of State Legislatures. “Making State Gas Pipelines Safe and Reliable: An Assessment of State Policy.” March 2011. <http://www.ncsl.org/research/energy/state-gas-pipelines-natural-gas-as-an-expanding.aspx>.
104. Energy Information Administration. “Interstate Pipeline Capacity on a State-to-State Level.” January 16, 2014. <http://www.eia.gov/naturalgas/data.cfm>. Accessed October 10, 2014.
105. Energy Information Administration. “U.S. Natural Gas Pipeline Projects.” 2014. <http://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xls>. Accessed September 24, 2014.
106. Energy Information Administration. “Natural Gas: About U.S. Natural Gas Pipelines.” 2007. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html.
107. Quadrennial Energy Review Analysis: INTEK Inc. “United States Fuel Resiliency: Part I – US Fuels Supply Infrastructure (Vol 1–3).” September 2014. <http://energy.gov/epsa/qer-document-library>.
108. Energy Information Administration. “Natural Gas: About U.S. Natural Gas Pipelines.” 2007. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html. Accessed July 28, 2014.
109. Energy Information Administration. “Natural Gas: About U.S. Natural Gas Pipelines.” 2007. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html. Accessed July 28, 2014.
110. American Gas Association. “How Does the Natural Gas Delivery System Work?” <http://www.aga.org/KC/ABOUTNATURALGAS/CONSUMERINFO/Pages/NGDeliverySystem.aspx>. Accessed July 30, 2014.
111. Energy Information Administration. “Natural Gas Compressor Stations on the Interstate Pipeline Network: Developments since 1996.” November 2007. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngcompressor/ngcompressor.pdf.
112. Terry D. Boss, Senior Vice President of Environment, Safety and Operations, the Interstate Natural Gas Association of America, personal communication, January 2015.
113. Environmental Protection Agency. “Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012.” EPA 430-R-14-003. April 15, 2014. <http://epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Main-Text.pdf>.
114. Energy Information Administration. “Natural Gas Compressor Stations on the Interstate Pipeline Network: Developments since 1996.” “November 2007. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngcompressor/ngcompressor.pdf.
115. Energy Information Administration. “First Westbound Natural Gas Flows Begin on Rockies Express Pipeline.” June 18, 2014. <http://www.eia.gov/todayinenergy/detail.cfm?id=16751>.
116. Energy Information Administration. “Natural Gas: About U.S. Natural Gas Pipelines.” 2007. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html. Accessed July 28, 2014.
117. Energy Information Administration. “Natural Gas: About U.S. Natural Gas Pipelines.” 2007. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html. Accessed July 28, 2014.
118. Energy Information Administration. “The Emergence of Natural Gas Market Centers.” 1996. http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/natural_gas_1996_issues_trends/pdf/it96ch3.pdf. Accessed August 4, 2014.
119. Federal Energy Regulatory Commission. “Energy Primer: A Handbook of Energy Market Basics.” July 2012. <http://www.ferc.gov/market-oversight/guide/energy-primer.pdf>.
120. Department of Energy, Office of Energy Policy and Systems Analysis. Energy Information Administration data. 2015.
121. Energy Information Administration. “Interstate Pipeline Capacity on a State-to-State Level.” January 16, 2014. <http://www.eia.gov/naturalgas/data.cfm>. Accessed October 10, 2014.
122. Energy Information Administration. “Interstate Pipeline Capacity on a State-to-State Level.” January 16, 2014. <http://www.eia.gov/naturalgas/data.cfm>. Accessed October 10, 2014.

123. Quadrennial Energy Review Analysis: BENTEK Energy. “The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments.” 2014. <http://energy.gov/epsa/qer-document-library>.
124. Quadrennial Energy Review Analysis: BENTEK Energy. “The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments.” 2014. <http://energy.gov/epsa/qer-document-library>.
125. Interstate Natural Gas Association of America Foundation. “Maximum Allowable Operating Pressure for Natural Gas Pipelines.” 2011. <http://www.ingaa.org/File.aspx?id=12366>.
126. Quadrennial Energy Review Analysis: Department of Energy, Office of Energy Policy and Systems Analysis. “Natural Gas Infrastructure Implications of Increased Demand from the Electric Sector.” February 2015. <http://energy.gov/epsa/qer-document-library>.
127. Department of Energy, Office of Energy and Policy Systems Analysis and the Federal Energy Regulatory Commission. Intercontinental Exchange transaction data. 2014.
128. Energy Information Administration. “Markets expect Marcellus growth to drive Appalachian natural gas prices below Henry Hub.” Today in Energy. October 9, 2013. <http://www.eia.gov/todayinenergy/detail.cfm?id=13331>. Accessed October 20, 2014.
129. Energy Information Administration. “Short-Term Energy Outlook Supplement: Constraints in New England likely to affect regional energy prices this winter in Independent Statistics & Analysis.” 2013.
130. Federal Energy Regulatory Commission. “Winter 2013-2014 Operations and Market Performance in RTOs and ISOs.” 2014.
131. Energy Information Administration. “Northeast and Mid-Atlantic power prices react to winter freeze and natural gas constraints.” Today in Energy. January 21, 2014. <http://www.eia.gov/todayinenergy/detail.cfm?id=14671>. Accessed October 20, 2014.
132. RBN Energy LLC. “I Believe (This) Can Fly—Pursuing Gas Pipeline Projects in the Northeast.” December 15, 2015. <https://rbnenergy.com/i-believe-this-can-fly-pursuing-gas-pipeline-projects-in-the-northeast>.
133. Department of Energy, Office of Energy Policy and Systems Analysis and Energy Information Administration. Intercontinental Exchange data. 2015.
134. RBN Energy LLC. “The Battle for Henry Hub.” 2014. <https://rbnenergy.com/reports/battle-for-henry-hub>.
135. Energy Information Administration. “Cold weather led to record-high natural gas storage withdrawals.” Today in Energy. January 17, 2014. <http://www.eia.gov/todayinenergy/detail.cfm?id=14651>. Accessed October 20, 2014.
136. Federal Energy Regulatory Commission. “2014 State of the Markets.” p. 17. March 19, 2015. <http://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2014-som.pdf>. Accessed April 1, 2015.
137. Energy Information Administration. “Natural Gas Weekly Update.” February 26, 2015. http://www.eia.gov/naturalgas/weekly/archive/2015/02_26/index.cfm. Accessed April 1, 2015.
138. Federal Energy Regulatory Commission. “2014 State of the Markets.” p. 17–21. March 19, 2015. <http://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2014-som.pdf>. Accessed April 1, 2015.
139. Department of Energy, Office of Energy and Policy Systems Analysis and the Federal Energy Regulatory Commission. Intercontinental Exchange transaction data. 2014.
140. Department of Energy, Office of Energy Policy and Systems Analysis. 2015.
141. Department of Energy, Office of Energy Policy and Systems Analysis. 2015.
142. Energy Information Administration. “U.S. natural gas pipeline projects.” December 31, 2014. <http://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xls>.
143. Energy Information Administration. “Marcellus natural gas pipeline projects to primarily benefit New York and New Jersey.” Today in Energy. October 30, 2013. <http://www.eia.gov/todayinenergy/detail.cfm?id=13591>.

144. RBN Energy LLC. “The Battle for Henry Hub.” 2014. <https://rbnenergy.com/reports/battle-for-henry-hub>.
145. RBN Energy LLC. “The Battle for Henry Hub.” 2014. <https://rbnenergy.com/reports/battle-for-henry-hub>.
146. Quadrennial Energy Review Analysis: Department of Energy. “Natural Gas Infrastructure Implications of Increased Demand from the Electric Sector.” February 2015.
147. Quadrennial Energy Review Analysis: BENTEK Energy. “The Future of U.S. Natural Gas: Supply, Demand, and Infrastructure Developments.” 2014. <http://energy.gov/epsa/qer-document-library>.
148. Quadrennial Energy Review Analysis: RAND Corporation. “Scenario Development for the 2015 Quadrennial Energy Review.” 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).
149. IHS. “Oil & Natural Gas Transportation & Storage Infrastructure: Status, Trends, & Economic Benefits.” American Petroleum Institute. December 2013
150. ICF International. “North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance.” Interstate Natural Gas Association of America. March 2013.
151. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. “Annual Report Mileage for Gas Distribution Systems.” July 1, 2014. <http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnnextoid=35d3f5448a359310VgnVCM1000001ecb7898RCRD&vgnnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnnextfmt=print>.
152. Energy Information Administration. “Distribution of Natural Gas: The Final Step in the Transmission Process.” 2008. http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2008/ldc2008/ldc2008.pdf. Accessed July 28, 2014.
153. Energy Information Administration. “Distribution of Natural Gas: The Final Step in the Transmission Process.” 2008. http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2008/ldc2008/ldc2008.pdf. Accessed July 28, 2014.
154. Energy Information Administration. “Distribution of Natural Gas: The Final Step in the Transmission Process.” 2008. http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2008/ldc2008/ldc2008.pdf. Accessed July 28, 2014.
155. Energy Information Administration. “Distribution of Natural Gas: The Final Step in the Transmission Process.” 2008. http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2008/ldc2008/ldc2008.pdf. Accessed July 28, 2014.
156. Energy Information Administration. “Distribution of Natural Gas: The Final Step in the Transmission Process.” 2008. http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2008/ldc2008/ldc2008.pdf. Accessed July 28, 2014.
157. Department of Energy, Office of Energy Policy and Systems Analysis. Energy Information Administration data. 2015.
158. Department of Energy, Office of Energy Policy and Systems Analysis. Department of Transportation, Pipeline and Hazardous Materials Safety Administration data. 2015.
159. Energy Information Administration. “Distribution of Natural Gas: The Final Step in the Transmission Process.” 2008. http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2008/ldc2008/ldc2008.pdf. Accessed July 28, 2014.
160. IHS. “Fueling the Future with Natural Gas: Bringing it Home.” Cambridge Energy Research Associates. January 2014.
161. American Gas Association. “Natural Gas Pipelines: Safe, Sound, and Underground.” <http://www.aga.org/Kc/aboutnaturalgas/consumerinfo/Pages/NGDeliverySystemFacts.aspx>. Accessed August 4, 2014.
162. Census Bureau. “Annual Capital Expenditures Survey.” April 24, 2013. https://www.census.gov/econ/aces/xls/2011/summary_of_findings.html.
163. Federal Energy Regulatory Commission. “2014 Commission and Industry Actions Relevant to Winter 2013-14 Weather Events.” Docket No. AD14-8. October 16, 2014.
164. Federal Energy Regulatory Commission. “2014 State of the Markets.” p. 17. March 19, 2015. <http://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2014-som.pdf>. Accessed April 1, 2015.
165. Terry D. Boss, Senior Vice President of Environment, Safety and Operations, the Interstate Natural Gas Association of America, personal communication, January 2015.

166. Energy Information Administration. "Natural Gas Compressor Stations on the Interstate Pipeline Network: Developments since 1996." November 2007. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngcompressor/ngcompressor.pdf.
167. Gas Electric Partnership Research Consortium. "Reliability Review of Electric Motor Drives for Pipeline Centrifugal Compressor Station." Presentation for the Gas Electric Partnership Conference. Southwest Research Institute. February 9, 2012.
168. Federal Energy Regulatory Commission and North American Electric Reliability Corporation. "Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011." August 2011. <http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf>.
169. Department of Energy. "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector." 2015. http://energy.gov/sites/prod/files/2015/02/f19/DOE%20Report%20Natural%20Gas%20Infrastructure%20V_02-02.pdf. Accessed March 16, 2015.
170. Argonne National Laboratory. "Salt Caverns and Their Use for Disposal of Oil Field Wastes." The National Petroleum Technology Office. 1999. <http://web.evs.anl.gov/saltcaverns/doc/SaltCavbroch.pdf>. Accessed January 28, 2015.
171. Department of Energy, Office of Energy Policy and Systems Analysis. Energy Information Administration data. 2015.
172. Spectra Energy. "Gas/Electric Webinar: Line Pack – What does it really do?" February 21, 2013.
173. Federal Energy Regulatory Commission. "Order Accepting Tariff Revisions." Docket No. ER14-2407-000, et al.
174. Federal Energy Regulatory Commission. "Order Accepting Tariff Revisions." Docket ER15-257-000. January 9, 2015. <http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13733471>.
175. Independent System Operator New England. "2014 Regional Electricity Outlook." 2014. http://www.iso-ne.com/static-assets/documents/aboutiso/fin/annl_reports/2000/2014_reo.pdf. Accessed January 21, 2015.
176. Interstate Natural Gas Association of America Foundation. "Firming Renewable Electric Power Generators: Opportunities and Challenges for Natural Gas Pipelines." March 16, 2011.
177. Federal Energy Regulatory Commission. "2014 State of the Markets." p. 17. March 19, 2015. <http://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2014-som.pdf>. Accessed April 1, 2015.
178. Quadrennial Energy Review Analysis: Keyser, D., E. Warner and C. Curley. "Quantification of the Potential Gross Economic Impacts of Five Methane Reduction Scenarios." Joint Institute for Strategic Energy Analysis. NREL/TP-6A50-63801. April 2015. <http://energy.gov/epsa/qer-document-library>.
179. The White House. "The President's Climate Action Plan." June 2013. <http://www.whitehouse.gov/sites/default/files/image/president27climateactionplan.pdf>.
180. The White House. "Strategy to Reduce Methane Emissions." March 2014. http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf.
181. Quadrennial Energy Review Analysis: Warner, E. et al. "Potential Cost-Effective Opportunities for Methane Emissions Abatement." Joint Institute for Strategic Energy Analysis and Department of Energy, Office of Energy Policy and Systems Analysis. NREL/TP-6A50-62818. April 2015. <http://energy.gov/epsa/qer-document-library>.
182. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Pipeline Incident 20 Year Trends." 2015. <http://www.phmsa.dot.gov/pipeline/library/datastatistics/pipelineincidenttrends>. Accessed February 25, 2015.
183. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Pipeline Serious Incidents 20 Year Trend." 2014. <http://www.phmsa.dot.gov/pipeline/library/datastatistics/pipelineincidenttrends>. Accessed March 4, 2015.
184. Government Accountability Office. "Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety." March 22, 2012. <http://www.gao.gov/products/GAO-12-388>. Accessed January 16, 2015.

185. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Pipeline Replacement Updates: Call To Action." http://opsweb.phmsa.dot.gov/pipeline_replacement/action.asp.
186. Regulatory Certainty and Job Creation Act of 2011, Public Law No. 112-90, 125 Stat. 1904 (2012).
187. National Transportation Safety Board and Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Recommendation P-11-10." 2011. <http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnnextoid=a11f603415d13310VgnVCM1000001ecb7898RCRD&vgnnextchannel=2a0dd7dcb2588110VgnVCM1000009ed07898RCRD&vgnnextfmt=print>.
188. National Transportation Safety Board. "Safety Study; Integrity Management of Gas Transmission Pipelines in High Consequence Areas." NTSB SS-15/01. 2015. http://www.nts.gov/news/events/Documents/2015_Gas_Transmission_SS_BMG_Abstract.pdf.
189. 49 C.F.R. § 192.763, 76 Fed. Reg. 165. January 3, 2011.
190. Shaw, D. et al. "Leak Detection Study." p. 4–5. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. 2012. http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_4A77C7A89CAA18E285898295888E3DB9C5924400/filename/Leak%20Detection%20Study.pdf. Accessed March 31, 2015.
191. Quadrennial Energy Review Analysis: Paranhos, E. et al. "Controlling Methane Emissions in the Natural Gas Sector – A Review of Federal & State Regulatory Frameworks Governing Production, Processing, Transportation, and Distribution." Joint Institute for Strategic Energy Analysis. NREL/TP-6A50-63416. April 2015. <http://energy.gov/epsa/ger-document-library>.
192. Yardley Associates. "Gas Distribution Infrastructure: Pipeline Replacement and Upgrades, Cost Recovery Issues and Approaches." Prepared for the American Gas Foundation. July 2012.
193. Environmental Protection Agency. "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013." Annex 3-Table A.140. p. A-195. April 2014. <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>. Accessed December 16, 2014.
194. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "2013 Gas Distribution Annual, from Form PHMSA F 7100.1-1 (rev 1-2011)." 2014.
195. American Gas Association. "The LDC Story: A Focus on Safety Also Benefits Our Environment." Public comments submitted to the Department of Energy for the Quadrennial Energy Review. October 10, 2014.
196. Environmental Protection Agency. "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012." <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.
197. American Gas Foundation. "Gas Distribution Infrastructure: Pipeline Replacement and Upgrades." 2012. <http://www.gasfoundation.org/researchstudies/agf-infrastructure-2012.pdf>.
198. Department of Energy, Office of Energy Policy and Systems Analysis. Data from various sources, including Philly.com; Connecticut Post; Wall Street Journal; USA Today; Huffington Post; Pittsburgh Tribune-Review; Baltimore Gas and Electric; Detroit Free Press; New York Times; Dominion East Ohio; Peoples Gas; Providence Journal; New York State Public Service Commission; and Conservation Law Foundation. 2015.
199. Friedman, A. "PSE&G will seek more money from N.J. to replace aging cast iron gas pipes." NJ.com. July 31, 2014. http://www.nj.com/business/index.ssf/2014/07/pseg_will_seek_more_money_to_replace_miles_of_aging_cast_iron_gas_pipes.html. Accessed January 12, 2015.
200. Lamb, B. et al. "Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States." Table S5.11. Environmental Science and Technology. <http://pubs.acs.org/doi/full/10.1021/es505116p>. Accessed April 1, 2015.
201. Environmental Protection Agency. "Natural Gas STAR Recommended Technologies and Practices – Distribution Sector." Natural Gas Environmental Protection Agency Pollution Preventer. October 2011. http://www.epa.gov/gasstar/documents/distribution_fs.pdf.

202. ICF International. "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries." March 2014. https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.
203. Environmental Protection Agency. "Greenhouse Gas Inventory, Annex 3 Table A136." <http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Annex-3-Additional-Source-or-Sink-Categories.pdf>.
204. 49 U.S.C. § 60102(b)(2)(D)(E).
205. Interstate Natural Gas Association of America and American Gas Association. "Report to the National Transportation Safety Board on Historical and Future Development of Advanced In-Line Inspection Platforms for Use in Gas Transmission Pipelines." March 23, 2012. http://www.prci.org/images/prci_uploads/NTSB_Response_Final_25Mar12.pdf.
206. Environmental Protection Agency. "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012." April 2014. <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>. Accessed December 16, 2014.
207. Environmental Protection Agency. "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012." April 2014. <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>. Accessed December 16, 2014.
208. Energy Information Administration. "Annual Energy Outlook." 2014. <http://www.eia.gov/forecasts/aeo>.
209. Department of State. "United States Climate Action Report 2014." 2014. <http://www.state.gov/documents/organization/219038.pdf>.
210. Myhre, G. et al. "Anthropogenic and Natural Radiative Forcing." In: Climate Change 2013: The Physical Science Basis. 2013. http://www.climatechange2013.org/images/report/WG1AR5_Chapter08_FINAL.pdf.
211. Environmental Protection Agency. "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012." April 2014. <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>. Accessed December 16, 2014.
212. Environmental Protection Agency. "U.S. Greenhouse Gas Inventory." 2014.
213. Quadrennial Energy Review Analysis: Department of Energy, Office of Energy Policy and Systems Analysis. "Greenhouse Gas Emissions and Fuel Use within the Natural Gas Supply Chain: Sankey Diagram Methodology." 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).
214. Environmental Protection Agency. "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012." April 2014. <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/archive.html>. Accessed May 4, 2015.
215. Quadrennial Energy Review Analysis: Department of Energy, Office of Energy Policy Systems Analysis. "Greenhouse Gas Emissions and Fuel Use within the Natural Gas Supply Chain: Sankey Diagram Methodology." 2015 (forthcoming at <http://energy.gov/epsa/qer-document-library>).
216. Paranhos, E. et al. "Controlling Methane Emissions in the Natural Gas Sector: A Review of Federal & State Regulatory Frameworks Governing Production, Gathering, Processing, Transmission, and Distribution." Joint Institute for Strategic Energy Analysis. 2015.
217. Environmental Protection Agency. "Global Mitigation of Non-CO₂ Greenhouse Gases: 2010-2030." Section II. 2013. <http://epa.gov/climatechange/EPAactivities/economics/nonco2mitigation.html>.
218. ICF International. "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and NG Industries." Prepared for the Environmental Defense Fund. March 2014. http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.
219. Quadrennial Energy Review Analysis: Warner, E. et al. "Potential Cost-Effective Opportunities for Methane Emissions Abatement." Joint Institute for Strategic Energy Analysis and Department of Energy, Office of Energy Policy and Systems Analysis. NREL/TP-6A50-62818. April 2015. <http://energy.gov/epsa/qer-document-library>.
220. Advanced Research Projects Agency-Energy. "Department of Energy Announces 22 New Projects to Enable Emissions Reductions and Improve Energy Efficiency." December 16, 2014. <http://arpa-e.energy.gov/?q=news-item/departement-energy-announces-22-new-projects-enable-emissions-reductions-and-improve-energy>.

221. Energy Information Administration. “Natural Gas Consumption by End Use.” http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm. Accessed January 15, 2015.
222. Energy Information Administration. “Annual Energy Outlook 2014.” Table A2. April 2014. <http://www.eia.gov/forecasts/aeo/pdf/tbla2.pdf>. Accessed January 15, 2015.
223. Environmental Protection Agency. “Inventory of Greenhouse Gas Emissions and Sinks: 1990-2012.” Table 3-43. April 2014. <http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Main-Text.pdf>. Accessed March 5, 2015.
224. Laurenzi, I.J. and G.R. Jersey. “Life Cycle Greenhouse Gas Emissions and Freshwater Consumption of Marcellus Shale Gas.” *Environmental Science & Technology*. 47(9). p. 4896–4903. 2013.
225. Quadrennial Energy Review Analysis: Greenblatt, J. “Opportunities for efficiency improvements in the U.S. natural gas transmission and distribution system.” Lawrence Berkeley National Laboratory. 2015. <http://energy.gov/epsa/qer-document-library>.
226. Environmental Protection Agency. “Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012.” April 2014. <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>. Accessed December 16, 2014.
227. The White House. “The President’s Climate Action Plan.” June 2013. <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>.
228. The White House. “Strategy to Reduce Methane Emissions.” March 2014. http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf.
229. Harrison, M. et al. “Methane Emissions from the Natural Gas Industry.” Prepared by Radian International LLC for the Environmental Protection Agency and Gas Research Institute. 1996. http://www.epa.gov/gasstar/documents/emissions_report/1_executiveummary.pdf.
230. Environmental Defense Fund. “Extensive research effort tackles methane leaks.” <http://www.edf.org/climate/methane-studies>. Accessed December 16, 2014.
231. Environmental Protection Agency. “National Emissions Inventory (NEI) Air Pollutant Emissions Trend Data.” <http://www.epa.gov/ttn/chief/trends/index.html>. Accessed February 25, 2015.
232. Environmental Protection Agency. “National Emissions Inventory (NEI) Air Pollutant Emissions Trend Data.” <http://www.epa.gov/ttn/chief/trends/index.html>. Accessed February 25, 2015.
233. Energy Information Administration. “Annual Energy Outlook.” 2014. <http://www.eia.gov/forecasts/aeo>.
234. Environmental Protection Agency. “2011 National Emissions Inventory, version 1.” November 2013. http://www.epa.gov/ttn/chief/net/2011nei/2011_neiv1_tsd_draft.pdf.