



Energy & Infrastructure Program

Energy Project

New Dynamics of the U.S. Natural Gas Market

A Report from the Staff
of the Bipartisan Policy Center

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BIPARTISAN POLICY CENTER



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This report was prepared by BPC staff to promote a better shared understanding of the issues surrounding U.S. natural gas markets. While the perspectives and assumptions that inform this report are consistent with those of other BPC Energy Project initiatives, the conclusions reached in this document do not necessarily reflect the views of the project's leadership, BPC, its founders, or its board of directors.

Advisory Group

To solicit input on our analysis, including input on supply and demand assumptions, scenarios, and results, BPC convened an advisory group of energy policy experts and stakeholders. Advisory group members provided invaluable technical assistance, information, and guidance to BPC staff throughout this process. While advisory group members were invited to review and provide comments on drafts of this report, they do not necessarily endorse each of the findings and conclusions put forward here.

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Executive Summary of Key Findings

Key Finding 1: The United States has ample domestic supplies to meet future demand for natural gas without significant price increases.

In BPC's modeling analysis, total U.S. dry natural gas production ranges from 67 to 81 billion cubic feet per day (bcf/d) in 2020, and natural gas production increases throughout the forecast period across all scenarios. The primary driver of differences in natural gas production across the scenarios is the level of shale gas production, which ranges from 25 to 38 bcf/d in 2020. The price of natural gas in the future will depend on total supply (domestic production plus any imports) and overall demand. Not surprisingly, prices are higher in the Low Supply, High Demand case (20 percent and 15 percent above the BPC Reference Case in 2020 and 2030, respectively). Conversely, prices are lower in the High Supply, Reference Demand case (18 percent and 25 percent below the BPC Reference Case in 2020 and 2030, respectively). But because the nation has an ample supply of natural gas, modeled prices in the scenario analysis never approach the annual levels that were recorded in past years when natural gas prices peaked. Finally, it is worth noting that, although modeled prices vary significantly across the different scenarios, four out of the six scenarios result in long-term prices that are either at the same level as, or below, the prices in the BPC Reference Case, and in all of the cases the United States has ample natural gas resources to meet high levels of domestic natural gas demand.

Key Finding 2: LNG exports are unlikely to have a large impact on domestic prices.

Factors that will determine future levels of liquefied natural gas (LNG) exports include the domestic price of natural gas, costs for transportation and liquefaction, and the price and level of demand for natural gas in target foreign markets. One of the fundamental drivers in this equation is the U.S. price of natural gas. The price of U.S. natural gas will influence LNG export levels far more than LNG exports will influence domestic prices. Accounting for all of these variables, BPC's scenario analysis produces a range of estimates for future LNG exports, from a low of 2 bcf/d to as much as 6.4 bcf/d by 2030. This range also seems plausible given the substantial barriers facing LNG projects, including the high cost of building facilities, liquefying and transporting natural gas overseas, and finding U.S. producers willing to enter into long-term low price contracts for natural gas. Overall, the United States is projected to become a net exporter of natural gas between 2017 and 2021 in all of the modeled scenarios. As domestic production of natural gas exceeds domestic consumption, the United States is projected to export natural gas via pipeline and as LNG.

However, contrary to the concerns recently expressed by some large users of natural gas, increased exports are likely to have only a modest impact on domestic gas prices.

Key Finding 3: Increased natural gas consumption in the future will be primarily driven by overall economic growth and increased demand in the electric power and industrial sectors.

Across the scenarios modeled, overall natural gas consumption in 2020 ranged from 73 bcf/d (down 2 percent from the BPC Reference Case) to 77 bcf/d (up 11 percent from the BPC Reference Case). These differences in modeled consumption levels were driven primarily by differences in overall economic growth, electric power sector demand, and industrial demand. Demand in the residential and commercial sectors was relatively unresponsive to the price of natural gas across all of the scenarios since both these sectors use natural gas to meet space heating and cooling needs, which are mostly determined by weather.

Key Finding 4: The industrial sector could be a major source of new demand for natural gas if projected growth in the U.S. manufacturing base is realized.

Recent years have seen a flurry of new industrial-sector investments aimed at taking advantage of low-price natural gas and abundant natural gas liquids (NGLs). The results of the BPC analysis are consistent with changes recently made in federal projections to catch up with these trends. In particular, NGLs, which are associated with the production of natural gas and oil, have many potential uses spanning nearly all sectors of the economy. Increased domestic production of natural gas will likely also result in greater domestic production of these liquids; this is a principal reason why a number of petrochemical producers and other industrial manufacturers are looking to return to the United States.

Key Finding 5: Natural gas vehicles stand to make significant gains in market share and vehicle miles traveled by 2030.

Recent studies suggest that heavy-duty vehicle operators could achieve substantial fuel cost saving by switching to natural gas. If these cost savings and infrastructure build outs are realized and current assumptions about consumer behavior are accurate, natural-gas-fueled heavy-duty trucks stand to make significant gains in market share and vehicle miles traveled by 2030. In BPC's High Demand, High Supply scenario, sales of heavy-duty natural gas trucks grow to account for 14 percent of all new vehicle sales and natural gas vehicles (NGVs) account for 9 percent of total heavy-duty vehicle miles traveled in 2030. Despite these substantial gains, transportation-sector consumption of natural gas (at roughly 1.5

bcf/d in 2030) remains relatively small as a fraction of overall U.S. consumption, accounting for only about 2 percent of total domestic demand.

Key Finding 6: In the electric power sector, natural gas leads, but renewables also play a significant role.

Across the scenarios modeled for this analysis, demand for natural gas from the electric power sector ranged from 20 bcf/d (about 5 percent below the BPC Reference Case) to nearly 26 bcf/d (more than 20 percent higher than the BPC Reference Case) in 2020. Most of the variation in power-sector consumption of natural gas in the model scenarios is driven by fuel switching within the sector. Across BPC's model scenarios, natural-gas fired generation increases to 1,171–1,727 billion kilowatt-hours (kwh)—or 25–33 percent of total U.S. electricity production—by 2030, depending on the modeled price of natural gas relative to other generation options. By comparison, projected generation from hydroelectric and other renewables in 2030 ranges from 683 to 812 billion kwh (equal to 14–16 percent of total generation). In the modeling analysis, generation from renewables is driven primarily by electricity demand, not natural gas supply. Increased demand for electricity is largely met by additional natural gas and renewables capacity. By 2030, cumulative additions of natural gas combined cycle capacity range from 36 to 91 gigawatts across the model scenarios, while additions of renewable electricity generation capacity, primarily from non-hydroelectric renewables, range from 24 to 64 gigawatts. Finally, BPC's modeling results show coal retirements across all of the scenarios, even in the high demand scenarios. Total coal retirements range from 25 to 60 gigawatts in 2030, with the bulk of these retirements occurring before 2018.

Key Finding 7: Energy-related carbon dioxide emissions are primarily driven by overall economic growth.

In BPC's modeling analysis, the primary drivers of energy-related carbon dioxide (CO₂) emissions are economic growth and changes in total energy demand. In addition, while not modeled in the scenarios considered in the BPC analysis, the rate of energy efficiency resource deployment (through both incentives and standards) will also be a key driver of future total energy demand.¹ Fuel switching in response to a greater abundance of low-cost natural gas appears to help mitigate increases in emissions as total energy demand grows. The CO₂ penalty from using more natural gas is relatively small as compared with increased use of other fossil fuels. This is particularly true if increased gas consumption is displacing coal, a considerably more carbon-intensive fuel. In the High Supply, Reference Demand scenario, CO₂ emissions remain near the BPC Reference Case levels. By 2030, CO₂ emissions in the High Demand scenarios are about 9 percent higher than in the BPC Reference Case scenario, primarily as a result of higher overall economic growth.

Key Finding 8: Pricing carbon results in greater emission reductions.

BPC modeled two scenarios that included a \$15-per-metric-ton price on CO₂ emissions in 2013 and escalates at a rate of 5 percent per year, in real terms, thereafter. Both scenarios result in additional reductions in energy-related CO₂ emissions, with total emissions falling 12–13 percent below the corresponding reference cases by 2030. In addition, implementing a price on CO₂ emissions has only a limited impact on natural gas prices in the medium-to-long term: Henry Hub natural gas prices are only 4–6 percent higher by 2020 and 1–3 percent higher by 2030 under the carbon price modeled for this analysis. Adding a carbon price does have the effect of pushing a significant amount of coal-fired power capacity into retirement. In BPC’s carbon price scenarios, cumulative coal retirements are roughly 63–74 gigawatts above reference levels by 2020. Additional coal retirements that occur after 2025 result in cumulative coal retirements of 69–87 gigawatts above reference levels in 2030. Most of this retired coal capacity is replaced with new natural gas capacity; new renewable capacity makes a smaller contribution even though renewable additions have a higher growth rate. As a result, natural gas becomes the dominant fuel used in the power sector, overtaking coal (in terms of total electricity generation) by 2015 in the High Supply case and by 2018 in the Mid Supply case. This does not occur in any of the non-carbon-price scenarios. Adding a carbon price also has an impact on natural gas exports. Because it increases demand for natural gas, particularly in the electric power sector, a carbon price reduces the amount of natural gas available for export. Thus, LNG exports decline by 10–11 percent in the CO₂ price scenarios compared with the corresponding reference cases.

Introduction

Natural gas is one of America's most important energy resources. Comparatively clean burning and less carbon intensive than oil or coal, it is used as a fuel in a wide variety of applications throughout the economy. Rapid technological advancements in horizontal drilling and hydraulic fracturing have unlocked a large volume of gas resources in North American shale gas formations. These developments have significant implications for the domestic supply outlook for natural gas, and for the potential to expand natural gas use in the U.S. economy.

A number of studies over the past few years have examined the impact of individual supply and demand drivers, such as natural gas use in the transportation sector, LNG exports, improvements in energy efficiency technologies, changes in the electric power sector fuel mix, and the varying size of natural gas resource base estimates, among other factors.² All of these studies have been useful and have contributed to an improved understanding of how the shale-driven shift in the natural gas resource base will affect natural gas markets and create new market opportunities for expanded gas use.

BPC sought to build on this work by analyzing the combined effect of multiple natural gas demand drivers under a range of supply assumptions. The analysis is designed to answer key policy questions: What are the price impacts when multiple demand drivers act in concert? How will price impacts vary under high and low supply assumptions? To address these questions, BPC staff undertook an energy scenario modeling exercise examining how new unconventional natural gas supplies might affect supply and demand dynamics in the domestic energy sector. The purpose of this effort is to develop realistic scenarios that usefully bound the range of plausible outcomes for natural gas supplies and demand over the next few decades, as well as potential impacts in terms of fuel mix, energy prices, and opportunities to expand natural gas use in ways that improve the environmental performance of the U.S. energy system.

To solicit input on the analysis and seek guidance on specific supply and demand assumptions, scenarios, and results, BPC convened an advisory group of energy policy experts and stakeholders. Advisory group members provided invaluable technical assistance, information, and advice to BPC staff throughout this process.

Scenarios

BPC constructed a suite of scenarios designed to examine various levels of natural gas supply and demand. Three supply cases—Low, Mid, and High—were combined with two demand cases—Reference and High—for a total of six scenarios (see Figure 1). In two additional scenarios, the Mid and High Supply cases were run with the High Demand case and a \$15-per-metric-ton price on CO₂ emissions in 2013 that escalates at a rate of 5 percent per year, in real terms, thereafter. All of these scenarios were compared with a base case (BPC Reference Case) consistent with projections developed by the U.S. Energy Information Administration (EIA) for its AEO2012.

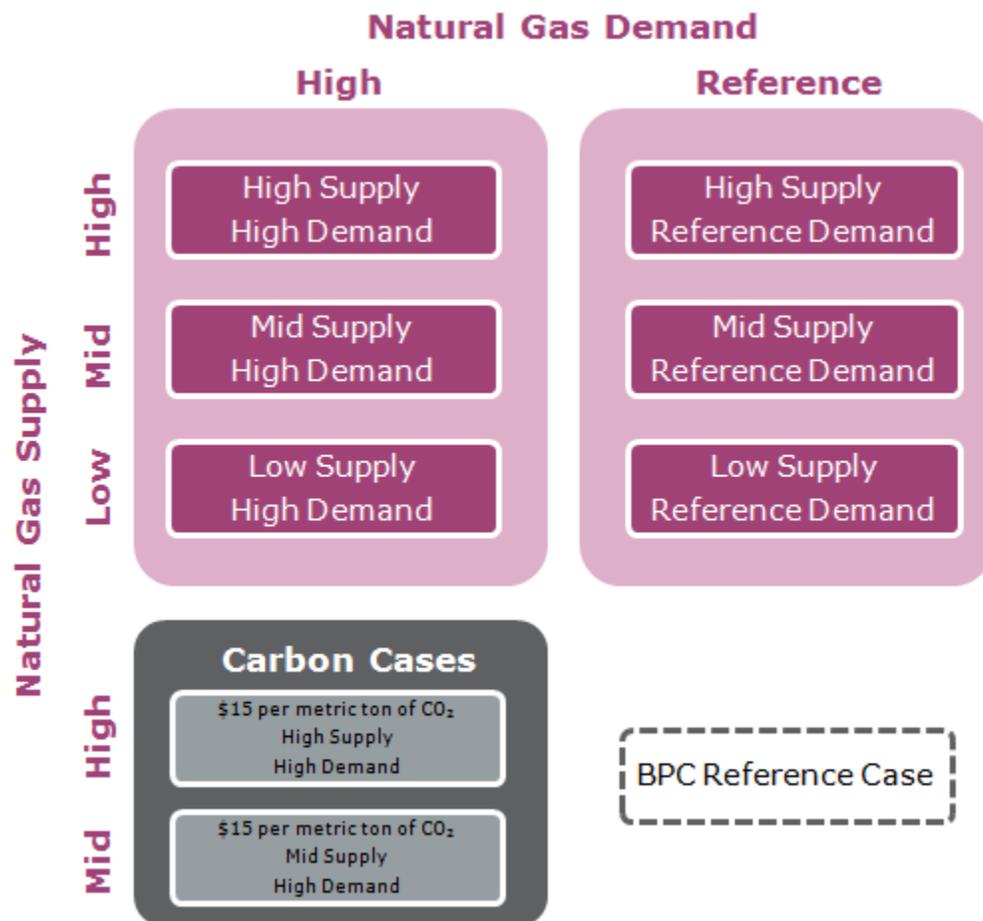


Figure 1: BPC Scenarios Matrix

To analyze the impacts of natural gas supply and demand drivers, BPC constructed a suite of six primary scenarios and two scenarios incorporating a price on emissions of carbon dioxide, which were compared with the BPC Reference Case.

To analyze the impacts of the supply and demand drivers detailed in this report, BPC used the National Energy Modeling System (NEMS), a detailed model of energy production and consumption used by the EIA to develop projections and assess policy options.³ NEMS explicitly represents domestic energy markets through the economic decision-making involved in producing, converting, and consuming energy products.⁴ In addition, NEMS projects energy production, imports, conversion, consumption, and prices, subject to assumptions about macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics.⁵ Finally, NEMS employs a modular structure that models distinct markets within the U.S. economy and distinguishes among different regions of the country.

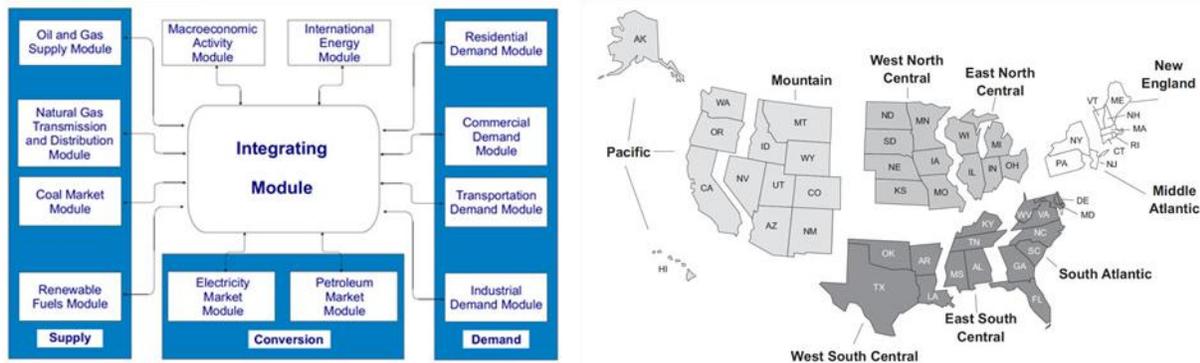


Figure 2: The NEMS Model

BPC used the National Energy Modeling System, a detailed model of energy production and consumption used by the U.S. Energy Information Administration to develop projections and assess policy options.

Supply Drivers

The outlook for North American supplies of natural gas has improved dramatically in recent years as horizontal drilling and hydraulic fracturing have made it possible to commercially develop tight gas and shale gas reserves. Effective and responsible development and use of these newly accessible resources provide an enormous opportunity for the United States as they have the potential to fundamentally improve the nation's economic and energy security.

As noted above, BPC staff considered three supply cases as part of this analysis. While industry continues to learn more about tight and shale resources with each passing day, some uncertainty still lingers over the rate of decline in well productivity because most existing shale wells are relatively young.⁶ This uncertainty is reflected in the Low Supply case assumptions. In addition, even though industry and regulators have been working to improve the safety and environmental performance of hydraulic fracturing, some states and localities are working to limit access to tight and shale petroleum resources.^{7,8} BPC's Low Supply case represents a hypothetical future where natural gas well recovery rates are low and access to these resources is constrained.

In the Mid and High Supply cases, by contrast, these constraints are relaxed to reflect a number of countervailing factors. First, the industry has a track record of continuous technological improvement that has enabled greater recovery rates at lower costs. Also, as time passes, more resources have been discovered and geologists have amassed more data on which to base their estimates. This in turn has led to large increases in the estimated size of the natural gas resource base. Table 1 shows how resource estimates for the Marcellus shale, the largest onshore natural gas play in the United States, have evolved from 2005 to 2012.

Table 1: Natural Gas Resource Estimates for the Marcellus Shale

Source	Release Date	Mean Recoverable Natural Gas Resources (Tcf)	Assumptions
U.S. Geological Survey ⁹	2005	1.9	Geologic mapping, historical recovery analysis, Monte Carlo assessment of total area, untested area, area with potential, well recovery, well spacing.
Dr. Terry Engelder, Pennsylvania State University ¹⁰	2009	220–489–867	P90–P50–P10 based on 70 percent access rate, 80 acre well spacing, 50-year decline.
Potential Gas Committee ¹¹	2011	55–170–472	Min-Mean-Max based on varying productive area, recovery, net to gross; 149-acre well spacing.
U.S. Geological Survey ¹²	2011	43–84–144	P95–Mean–P5 based on fully risked estimates.
Energy Information Administration ¹³	2011	410	Analysis using risked recoverable method based on well recovery distribution for given number of well spots.
National Petroleum Council ¹⁴	2011	177–546	Range for Navigant 08, PGC 08, EIA 11, and ANGA 10 Estimates.
Energy Information Administration ¹⁵	2012	141	Based on upper-range of USGS 2011.
ICF International ¹⁶	2012	461–698	Gas in-place using mapped geology; risked recovery method based on several factors; 40 and 80 acre well spacing.

National estimates of natural gas resources have continued to evolve over the years, including in 2013. The Colorado School of Mines’ Potential Gas Committee (PGC) released their 2008 assessment of the U.S. natural gas resource base that was the highest in the committee’s 44-year history and 45 percent higher than the committee’s previous (2006) estimate—largely as a result of new data on the extent of shale gas plays.¹⁷ Two years later, the PGC released a new estimate showing a roughly 4 percent increase in the estimated resource base. A still more recent assessment, issued by the PGC in April 2013,

increased the estimated size of the natural gas resource base by another 25 percent in light of new evaluations of shale resources throughout the country. This consistently upward-sloping trend in recent estimates of the size of the natural gas resource base, together with the recognition that extraction technology continues to evolve and improve, forms the basis for BPC’s Mid and High Supply cases.

The U.S. government, through the U.S. Geological Survey (USGS) has also revisited its natural gas resource estimates in recent years. The USGS estimates are typically incorporated into EIA forecasts. The EIA’s AEO2013 Early Release noted that “improved drilling efficiencies, which result in a greater number of wells being drilled more quickly, with fewer rigs and higher initial production rates” as well as “continued success in tapping the nation’s extensive shale gas resource” resulted in increased natural gas production in the AEO reference forecast.¹⁸ Estimates of the size of the natural gas resource base were also revised upward for EIA’s AEO2013 Early Release reference case. As a result of these changes, natural gas supply figures in the AEO2013 Early Release are higher than in the AEO2012 and roughly on par with the BPC’s Mid Supply case. The assumptions used to create the BPC supply cases are described in detail later in this section.

Comparison of Lower-48 Natural Gas Resource Estimates and Comparison to BPC Supply Cases

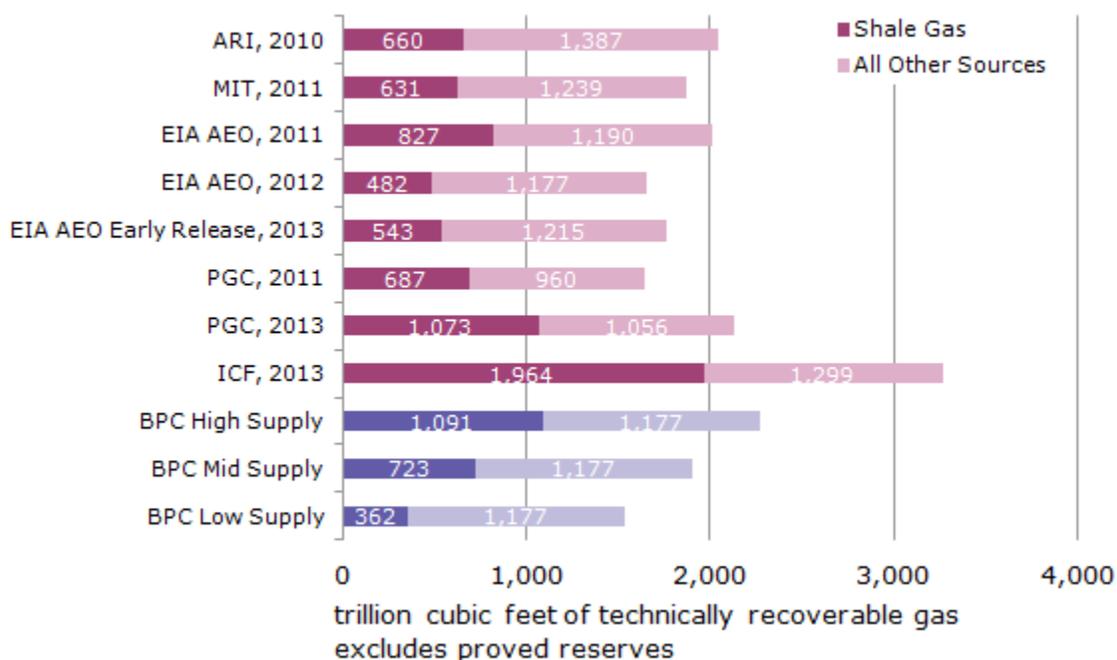


Figure 3: Comparison of Lower-48 Natural Gas Resource Estimates and Comparison with BPC Supply Cases^{19,20}

BPC considered three supply cases to capture a range of uncertainty and optimism in estimates of the U.S. natural gas resource base. BPC also considered additional drivers of natural gas supply, such as estimated ultimate recovery and well spacing.

In NEMS, natural gas supply is influenced by several factors and is not solely dependent on the raw size of resource estimates. This analysis considers four key drivers of natural gas supply:

- **Technically recoverable resources (TRR)**—The amount of natural gas in producing formations, referred to as the resource base, consists of proved reserves and unproven resources.²¹ TRR, as defined by the USGS, represent the portion of assessed in-place natural gas that can be recovered using current technology without regard to cost. Given the uncertainty around the size of the shale gas resource base, BPC staff considered three levels of shale resource estimates, ranging from 362 trillion cubic feet (tcf) in the Low Supply case, 723 tcf in the Mid Supply case, and 1,091 tcf in the High Supply case.
- **Estimated ultimate recovery (EUR)**—The quantity of natural gas that is potentially recoverable from a well. BPC staff considered a range of EURs, from 25 percent lower than the AEO2012 Reference Case to 50 percent higher than the AEO2012 Reference Case.
- **Well spacing density**—The average number of wells drilled per square mile, which serve as a proxy for the production productivity per square mile. When wells are located closer together it is possible to recover more of the natural gas from the producing formation. BPC staff considered two well spacing densities: an average of four wells per square mile in the Low and Mid Supply cases and six wells per square mile in the High Supply case.
- **Technology and capital constraints**—Advances in technology—including improved techniques for drilling, well completion, production, and processing—also impact supply. Similarly, NEMS contains assumptions on the level of capital that producers can risk, or invest in drilling and production, at any given time, which in turn can affect the supply of natural gas in the model. BPC staff did not modify these assumptions for this exercise, but clearly technology and capital constraints are significant drivers of future natural gas supply.

Table 2: BPC Supply Case Assumptions

	Low Supply Case	Mid Supply Case	High Supply Case
Estimated Ultimate Recovery per Shale Well	25 percent <i>lower</i> than AEO2012 Reference	50 percent <i>higher</i> than AEO2012 Reference	50 percent <i>higher</i> than AEO2012 Reference
Total Recoverable Shale Resources	<i>Decreased</i> shale gas TRR to 362 tcf	<i>Increased</i> shale gas TRR to 723 tcf	<i>Increased</i> shale gas TRR to 1,091 tcf
Well Spacing Density	4 wells per square mile	4 wells per square mile	6 wells per square mile
Technology and Capital Constraints	AEO2012 Reference assumptions	AEO2012 Reference assumptions	AEO2012 Reference assumptions

Demand Drivers

Natural gas is the second-largest primary source of energy consumed in the United States. However, natural gas is also unique among energy sources in that it plays a major role in multiple sectors of the economy. As Figure 4 demonstrates, coal, nuclear, and hydropower resources are used almost exclusively in the power sector. Petroleum is primarily used for transportation, and only secondarily as an energy source and petrochemical feedstock in the industrial sector. Natural gas, by contrast, is used as a fuel in the residential, commercial, power, and industrial sectors; in addition, it is used as a chemical feedstock.²²

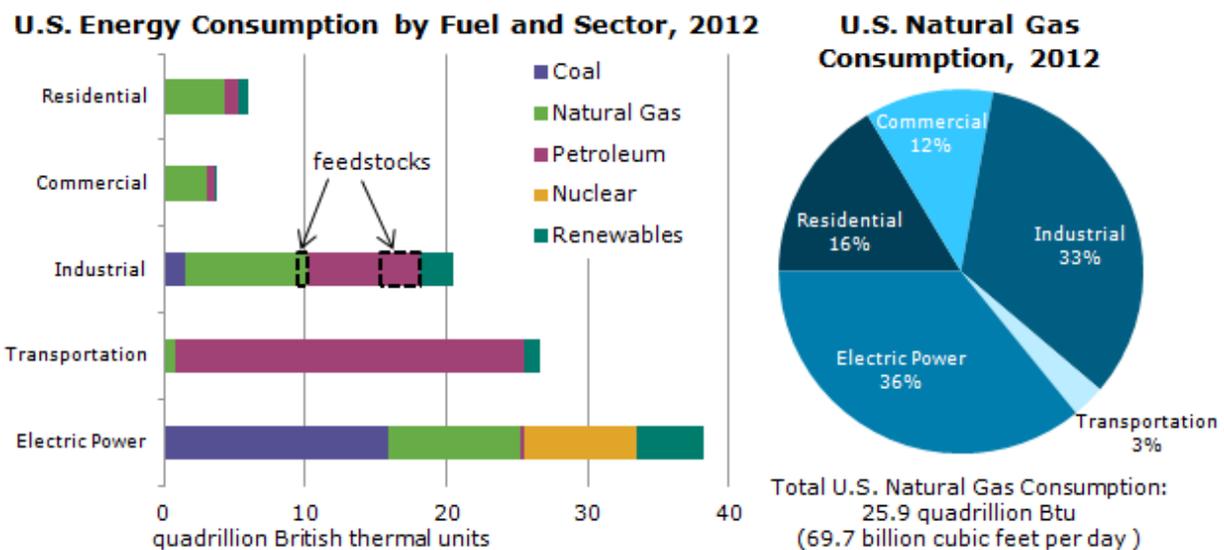


Figure 4: U.S. Energy Consumption by Fuel and Sector, 2012²³
 Natural gas is used as a fuel in the residential, commercial, electric power, and industrial sectors, and also as a chemical feedstock.

The prospect of more abundant low-price natural gas has prompted interest in expanding efficient natural gas applications in a variety of sectors and uses. For example, natural gas could be used more extensively in the transportation sector—either directly as a fuel or indirectly to generate power for electric vehicles—as one means of reducing U.S. oil dependence and carbon emissions while potentially also lowering transportation costs. Similarly, access to low-cost, abundant domestic natural gas would be a boon to the U.S. manufacturing sector, which uses gas as a fuel source for boilers and as a feedstock. Natural gas also plays a significant role as a fuel in the electric power sector. In 2012, natural gas accounted for 30 percent of net electricity generation in the United States, a 30-year high.²⁴ Record-low natural gas prices have lowered the cost of natural-gas-fired generation relative to other fuels, most notably coal. In the electric power sector, natural gas is also positioned as a natural partner to renewable power projects, where gas-fired turbines complement intermittent renewable power sources such as wind and solar. Finally, the expanded U.S. supply outlook is prompting interest in natural gas export opportunities.

Recently, some owners of LNG import terminals have applied for export authorization and have indicated that they plan to install liquefaction facilities.

This section describes the components of BPC’s natural gas demand cases. The goal was to build a high demand case that combines an aggressive but realistic set of demand drivers. BPC staff considered two cases: a Reference Demand case, based on the EIA’s AEO 2012 Reference Case, and a High Demand case, based on a series of assumptions described below. Given that demand is currently low and remains low in EIA’s Reference forecast, BPC staff did not consider a low demand case, as it would not have added a new data point to the analysis.

The BPC Reference Demand case includes all of the EIA’s AEO 2012 Reference Case assumptions. The High Demand case is summarized in Table 3; the remainder of this section describes each discrete demand driver in detail.

Table 3: BPC High Demand Case Assumptions

Demand Driver	High Demand Case
LNG Exports	LNG exports are determined based on domestic natural gas prices, cost of liquefaction and transportation, and global demand for U.S. LNG exports. As a result, the level of LNG exports varies across scenarios.
Pipeline Exports to Mexico	U.S. exports of natural gas to Mexico increased to 4.5 billion cubic feet per day in 2020 and to 5.7 billion cubic feet per day in 2035.
Natural Gas Vehicles (NGVs)	Assumes lower incremental costs for heavy-duty vehicles. Assumes greater availability of refueling infrastructure to support an expansion of the NGV fleet. Assumes higher potential market penetration for heavy-duty NGVs by positing that heavy-duty vehicle owners will consider purchasing an NGV if justified by the fuel economics over a payback distribution with a weighted average of three years.
Economic Growth	Economic growth rate of 3.1 percent per year from 2012 to 2035 (same as EIA’s High Macroeconomic Growth Case).
Industrial Sector Output	Increases industrial sector output by 15 percent above levels in the EIA’s High Macroeconomic Growth Case.
Electric Power Sector	Assumes all renewable energy subsidies sunset immediately; no new renewable energy subsidies.

Nuclear Power

Assumes retirement of nuclear power plants that have announced retirement or that have been identified in the press as facing pressure to retire.

This assumption results in 14.8 gigawatts of nuclear capacity retirements by 2035, as compared with 6.1 gigawatts of capacity retired in the same timeframe under the AEO2012 Reference Case.

LNG Exports

Less than a decade ago, most market experts were anticipating a large increase in LNG imports to the United States as domestic natural gas production fell and prices rose.²⁵ There were numerous proposals to expand existing LNG import facilities and to build new import terminals—in fact, the Federal Energy Regulatory Commission (FERC) had received 43 such applications by 2006.²⁶ Today, by contrast, the policy discussion is almost entirely focused on whether to export LNG *from* the United States, a question that has prompted intense debate among stakeholders in the natural gas market as well as among policy makers in Congress and in the executive branch. To date, the U.S. Department of Energy (DOE) has approved one permit application for a new export terminal—the Sabine Pass project in Louisiana. And 25 additional applications are under review.^{27,28} The DOE application is just one step of many—including FERC approval, entering into long-term purchase and sale contracts for natural gas, and soliciting capital investments—before constructing an export terminal. Given these hurdles, it is unlikely that all of these terminals would ultimately be constructed, even if the permits receive DOE approvals.

A topic of active analysis and debate within the energy policy community is how expanded exports will affect U.S. natural gas markets. Some parties to this debate argue for moving aggressively to capitalize on the potential economic benefits of new export opportunities, while others caution that it may be worth preserving the U.S. economy's relative insulation from global natural gas markets. Policymakers and stakeholders have voiced concern that increased exports could drive up the price of natural gas domestically, which in turn would raise energy costs for households, businesses, and the manufacturing sector. Some U.S. manufacturers who utilize natural gas as a fuel or feedstock have been particularly vocal about the possibility that an export-driven increase in the price of natural gas would adversely affect their ability to compete in the global market for commodities such as petrochemicals, fertilizer, steel, tires, and other products.

Over the past three years, several studies have assessed the market for U.S. LNG exports and explored the potential impacts of expanded exports on domestic natural gas prices. The Brookings Energy Security Initiative recently reviewed these studies in detail²⁹ and found that estimates of the impact of LNG exports on U.S. natural gas prices ranged from a 2 percent increase to an 11 percent increase compared with a baseline scenario that includes no LNG exports.³⁰ Similarly, in a recent discussion paper titled *A Strategy for Natural Gas*

Exports, Michael Levi of the Council on Foreign Relations wrote: “[T]o the extent that allowing exports leads to potentially worrisome rises in domestic natural gas prices, exports are likely to be self-limiting. ... Strong increases in domestic prices will make exports less attractive overseas. Large export volumes would most likely close off additional exports before U.S. prices could rise too far.”³¹ Finally, a study by Kenneth Medlock III, of Rice University’s James A. Baker III Institute for Public Policy, reached similar conclusions: “[D]omestic market interactions with the market abroad will determine export volumes and therefore U.S. domestic prices.” Overall, Medlock finds that “LNG exports will not likely produce a large domestic price impact.”³²

DOE recently released a long-awaited study by NERA Economic Consulting that examined the macroeconomic impacts of LNG exports.³³ According to DOE, the NERA study is “part of a broader effort to further inform decisions related to LNG exports...in order to gain a better understanding of how U.S. LNG exports could affect the public interest, with an emphasis on the energy and manufacturing sectors.”³⁴ The study authors found that the United States would realize “net economic benefits from allowing LNG exports”; they also concluded that allowing LNG exports would have a minimal impact on domestic prices because importers would not purchase U.S. LNG if wellhead prices rise above the cost of competing supplies.³⁵ While this result holds for the U.S. economy as a whole, the NERA study did find that some sectors could be adversely affected; in particular, energy-intensive U.S. manufacturers who rely on natural gas as a fuel or feedstock could be subject to “[s]erious competitive impacts.”³⁶

BPC’s modeling effort considered LNG exports within a global supply and demand framework. Specifically, BPC modified the NEMS model so that LNG export volumes are determined by the price of U.S. natural gas relative to the price of competing LNG on the global market and the price for LNG in consuming countries.³⁷ The BPC framework also builds in costs associated with exporting LNG, including the cost of building export terminals, developing liquefaction capacity, and providing transportation to foreign markets. These modeling changes are reflected in the BPC Reference Case and all of the scenarios.

Pipeline Exports to Mexico

Net exports of natural gas to Mexico have been growing rapidly in recent years; in fact, net pipeline exports doubled in the last two years alone—to a record 1.7 bcf/d in 2012, the highest level since data collection began in 1973.³⁸ (The United States has been a net exporter of natural gas to Mexico since 1984.)

Total U.S. natural gas pipeline export capacity to Mexico is currently estimated at nearly 3.8 bcf/d, according to January 2013 capacity data.³⁹ In recent months, a number of new pipeline export projects have been announced in Texas and Arizona to respond to growing demand for natural gas from industrial and power sector consumers in Mexico (see Figure 5). Taken together, these proposed projects would increase pipeline export capacity to Mexico by as much as 3.5 bcf/d.⁴⁰ In the High Demand case, BPC assumed that the volume of U.S. exports of natural gas to Mexico would increase to roughly 4.5 bcf/d in 2020 and about 4.9 bcf/d in 2030. In comparison, the AEO2012 Reference Case assumes exports to

Mexico total 2.5 bcf/d in 2020 and 4.0 bcf/d in 2030. EIA's export estimates are likewise evolving—in the AEO2013, pipeline exports to Mexico are projected to total 3.1 bcf/d in 2020 and 4.8 bcf/d in 2030.

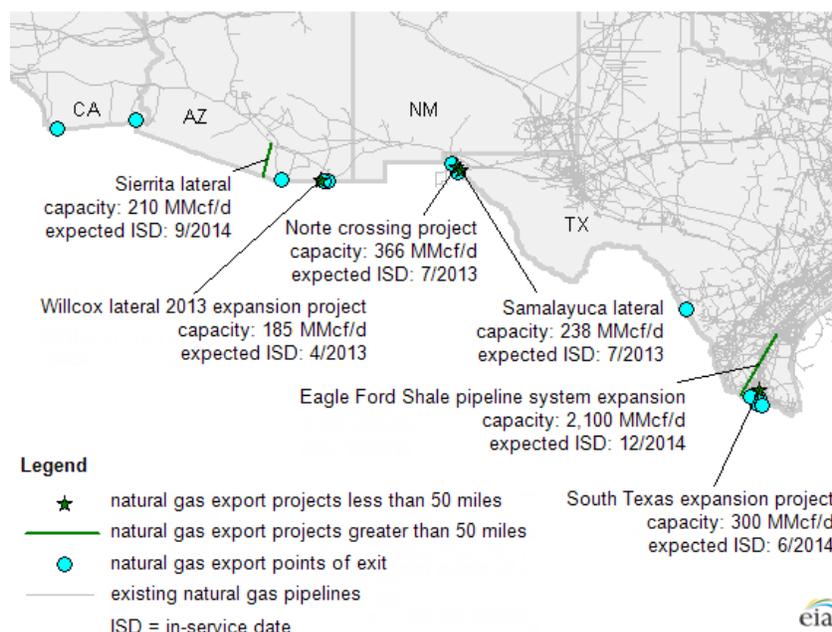


Figure 5: Major Proposed Natural Gas Pipeline Projects for Exports to Mexico⁴¹

In recent months, a number of new pipeline export projects have been announced in Texas and Arizona to respond to growing demand for natural gas from industrial and power sector consumers in Mexico.

Natural Gas Vehicles

The recent shale gas boom has also prompted renewed interest in expanding natural gas applications in the transportation sector. Many cities and private businesses already utilize natural gas as a transportation fuel, predominantly in centrally-fueled fleets, where lower infrastructure costs make these projects more attractive to developers and municipalities. There are also initiatives underway to convert heavy-duty truck fleets from petroleum-based fuels to compressed or liquefied natural gas. Initial experience from pilot projects and early adopters has demonstrated that these projects can allow operators to realize significant savings over petroleum-fueled vehicles. The key barrier to widespread adoption of natural gas as a transportation fuel is the high incremental cost of vehicles and infrastructure, along with the chicken-and-egg problem of building out refueling infrastructure before a significant market for the fuel exists. In the High Demand case, BPC reduced the incremental cost of heavy-duty NGVs by roughly 19 percent (see Table 4),⁴² relaxed NEMS assumptions that require the presence of refueling infrastructure to support an expansion of the NGV fleet and increased the potential market penetration of heavy-duty NGVs by assuming that heavy-duty vehicle owners would consider purchasing an NGV if the fuel economics justified

switching to natural gas over a payback distribution with a weighted average of three years.⁴³

Table 4: Incremental Cost of Natural Gas Trucks

Vehicle Class	Class 3 Light-Duty, 10,001 – 14,000 lbs	Class 4-6 Medium-Duty, 14,001 – 26,000 lbs	Class 7-8 Heavy-Duty, 26,001 lbs or more
BPC Reference Case	\$10,000–\$37,000	\$34,000–\$69,000	\$49,000–\$86,000
BPC High Demand case	\$10,000–\$27,000	\$34,000–\$45,000	\$58,000–\$70,000

Economic Growth

Economic growth is among the largest drivers of energy demand. As such, BPC’s analysis considered the potential for higher future macroeconomic growth. In the High Demand case, the U.S. economy was assumed to grow at an average annual rate of 3.1 percent per year for the period from 2012 to 2035. (By comparison the Reference Demand case assumes an average economic growth rate of 2.6 percent per year over the same time period.)⁴⁴ The energy productivity of the U.S. economy has improved dramatically over the last 40 years, and one of the key drivers of this trend has been the deployment of energy-efficient technologies and processes. While BPC’s analysis did not consider varying the rate of future energy efficiency resource deployment (through both incentives and standards), these measures will be a key driver of future total energy demand.⁴⁵

Industrial Sector Output

Low-cost, abundant domestic natural gas clearly represents a boon to U.S. manufacturers. A wave of reinvestment in gas-based infrastructure is already underway, and recent gas-related investment announcements by the petrochemical, steel, gas-to-liquid fuels, and vehicle tire industries now tally in the tens of billions of dollars. For example:

- Dow Chemical has announced \$4 billion in cumulative investments in ethylene and propylene facilities from April 2011 to April 2012 in the Gulf Coast region of Texas. Dow’s announcement specifically cited shale production as a driver behind these investment decisions.⁴⁶
- In 2011, Royal Dutch PLC said it would build a \$2 billion chemicals plant in Pennsylvania near Pittsburgh. The plant will upgrade ethane produced from the Marcellus Shale. Shell signed a land option to begin site evaluation in March 2012.^{47,48}
- Nucor Steel is nearing completion of a \$750 million direct-reduced iron plant in Convent, Louisiana. The plant will use natural gas to strip oxygen from iron or to make pellets of direct-reduced iron, which in turn are used to make steel.⁴⁹
- Formosa Plastics Corp., the U.S. affiliate of a Taiwan-based chemical maker, announced plans to build an ethylene cracker, a propane dehydrogenation unit, and a low-density polyethylene resin plant on the Texas Gulf Coast at a cost of about \$1.7 billion.⁵⁰

- Sasol recently announced plans to build a new plant that will convert natural gas into diesel fuel in Lake Charles, Louisiana.⁵¹ The plant will also include an integrated ethane cracker.

Consistent with the potential for significant future growth in the industrial sector, BPC's High Demand case assumes a level of industrial sector output (represented in the model as the value of shipments from this sector) in 2030 that is 12 percent above the level used in EIA's high macroeconomic growth rate case for the AEO2012.

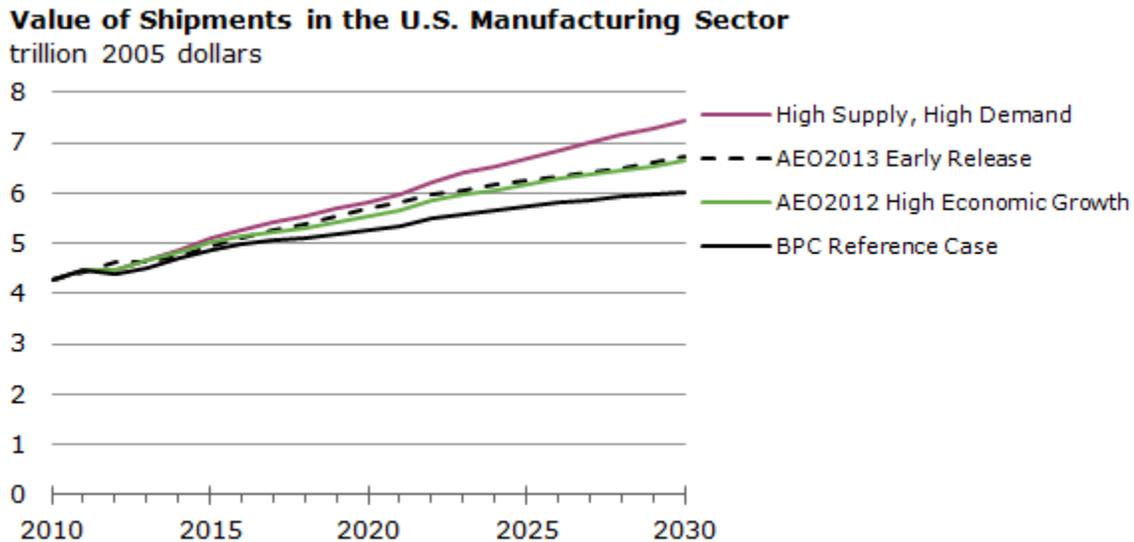


Figure 6: Value of Shipments from the U.S. Manufacturing Sector
 BPC created a High Demand case that considers the potential for significant future growth in the industrial sector. The High Demand case assumes a level of industrial sector output (represented in the model as the value of shipments from this sector) in 2030 that is 12 percent above the level used in EIA's high macroeconomic growth rate case for the AEO2012.

Electric Power Sector

The electric power sector in the United States faces a market environment that is changing rapidly in response to rising coal prices, low electricity demand growth, new environmental regulations, uncertain renewable energy incentives, and an aging coal and nuclear fleet. The price of natural gas and its use in the electric power sector has a significant effect on competing generation options, particularly coal and renewable generators, which must compete with gas-fired power to meet electricity demand. Over the last five years, record-low natural gas prices have accelerated a shift away from coal and toward natural gas in the electric power sector, with natural-gas-fired generation growing by 9 percent and coal generation declining by 10 percent between 2007 and 2012. As a result, natural gas generation accounted for 30 percent of net U.S. electricity production in 2012, nearly as much as coal at 34 percent of net generation.⁵² BPC's High Demand case is designed to

capture several factors that could drive faster growth in natural gas demand from the electric power sector going forward, including growth in total electricity demand, accelerated retirements of coal-fired power plants, slower growth in renewables, and nuclear plant retirements. In addition, the High Demand case assumes that all renewable energy subsidies are sunset immediately and are not renewed during the forecast period, reflecting the fact that many expiring renewable energy incentives face a difficult path to renewal in light of current budget constraints.

BPC's High Demand case also makes a number of assumptions that reflect the prospects for an aging nuclear power plant fleet in the United States. Specifically, the High Demand case assumes that any nuclear power plant that has either already announced retirement or has been named in the press as facing political pressure to retire will be shut down during the forecast period. This assumption results in the retirement of 14.8 gigawatts of nuclear capacity by 2035, versus 6.1 gigawatts in the AEO2012 Reference Case.

Future Climate Change Mitigation Requirements

To assess the potential impact of future policies to limit energy-sector CO₂ emissions, BPC modeled two scenarios that include a carbon price. In both scenarios the carbon price starts at \$15 per metric ton of CO₂ in 2013 and escalates at a rate of 5 percent per year, in real terms, thereafter. The two carbon control scenarios differ in that one applies the Mid Supply case assumptions for natural gas supply, while the other uses the High Supply case assumptions; both scenarios assume high demand. Neither scenario is intended to model any particular policy or plan for mitigating climate change; rather, applying a carbon price is simply the most straightforward and practical modeling mechanism for measuring the implications of a market where participants internalize the external costs of greenhouse gas emissions.

The two climate-change mitigation scenarios also impose constraints on the deployment of new nuclear power plants. Specifically, new nuclear capacity additions are limited to 20 gigawatts above the BPC Reference Case level, or roughly double the number of plants that are constructed in the AEO2012 Reference Case. (AEO2012 adds 9.6 gigawatts of nuclear generation capacity from 2012 to 2035.)

Key Findings

Before reviewing key findings from the scenario modeling exercise, it is important to emphasize that the BPC analysis was not designed to produce projections of how U.S. energy markets are likely to evolve in the future. Rather, the analysis is designed to explore the relative impact of different supply and demand drivers that are likely to shape U.S. energy markets—and the market for natural gas in particular—over the next several decades. Thus, it is more informative to concentrate on how each scenario varies from the BPC Reference Case and from the other scenarios.

This is especially true because energy markets are subject to a large degree of uncertainty—indeed, many past projections have proved inaccurate because so many of the events that shape energy markets are difficult to predict and cannot be anticipated. A significant drop in natural gas prices—such as occurred in 2012, for example—can dramatically shift the quantitative outputs from the modeling exercise. This is not to say that the results of the modeling exercise are uninformative—on the contrary, comparisons between the different scenarios and the baseline reference can provide meaningful insights into how key supply and demand developments are likely to affect the complex dynamics of energy markets.

Key Finding 1: The United States has ample domestic supplies to meet future demand for natural gas without significant price increases.

The United States has ample domestic supplies of natural gas to meet a multitude of potential future sources of demand without significant price increases compared with BPC Reference Case projections. Future levels of natural gas production will depend on both the available resource base and overall demand (see Figure 7).

U.S. Dry Natural Gas Production

billion cubic feet per day

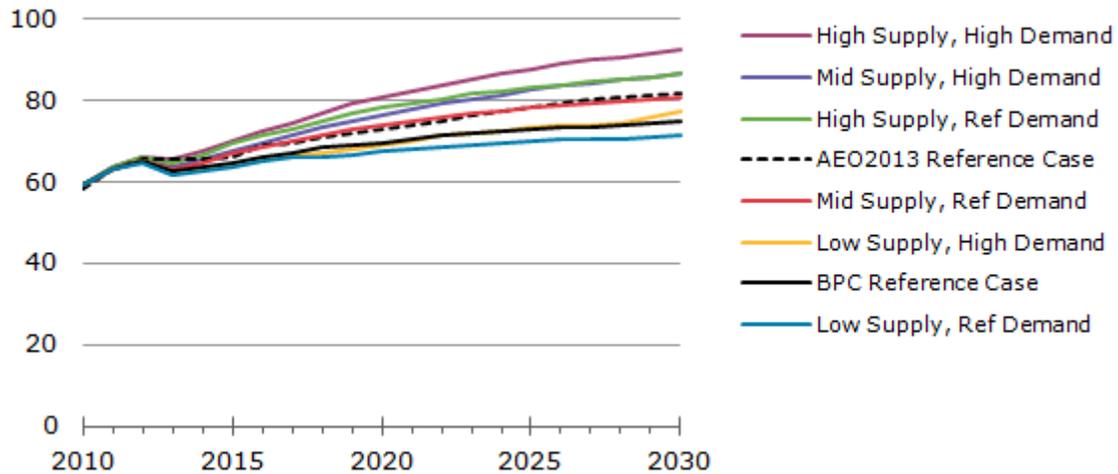


Figure 7: U.S. Dry Natural Gas Production

Future levels of natural gas production will depend on both the available resource base and overall demand. In BPC’s modeling analysis, total U.S. dry natural gas production ranges from 67 to 81 bcf/d in 2020, and natural gas production increases throughout the forecast period across all scenarios.

In BPC’s modeling analysis, total U.S. dry natural gas production ranges from 67 to 81 bcf/d in 2020, and natural gas production increases throughout the forecast period across all scenarios. The primary driver of differences in natural gas production across the scenarios is both the cost and availability of natural gas resources and the demand for natural gas. Shale gas shows the widest range of production across the scenarios, from 25 to 38 bcf/d in 2020. When a large natural gas resource base is coupled with high natural gas demand, the result is increased natural gas production. (Production in the High Supply, High Demand scenario is 16 percent higher than in the BPC Reference Case for 2020.) Alternatively, a small natural gas resource base with low demand results in lower levels of production. (Production in the Low Supply, Reference Demand scenario is 3 percent lower than in the BPC Reference Case for 2020.)

The price of natural gas in the future will depend on total supply (domestic production plus any imports) and overall demand. Largely because the nation has an ample supply of natural gas, modeled prices in the scenario analysis never approach the annual levels that were recorded in past years when natural gas prices peaked (see Figure 8).

U.S. Henry Hub Natural Gas Price

2010 dollars per million British thermal units

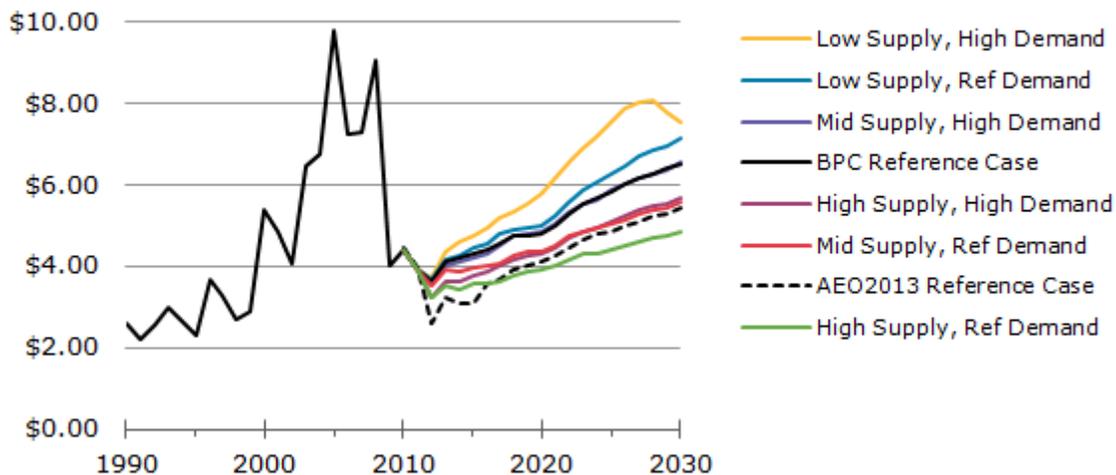


Figure 8: U.S. Henry Hub Natural Gas Price

Modeled prices never approach the levels that were recorded in past years when natural gas prices peaked. Prices are lowest when the available supply of natural gas is high but demand is low. Conversely, natural gas prices are highest when there is high demand for natural gas but supply is low.

As stated previously, however, it is more important to focus on relative price changes from the BPC Reference Case across the individual scenarios rather than focusing on the specific price levels forecast in the modeling analysis, since these forecasts are inherently uncertain. Not surprisingly, prices are lowest when the available supply of natural gas is high but demand is low; thus, the High Supply, Reference Demand scenario yields natural gas prices that are 18 percent, or \$0.86 per million BTU, below the BPC Reference Case in 2020 and 25 percent below the Reference Case in 2030. Conversely, natural gas prices are highest when there is high demand for natural gas but supply is low; thus, the Low Supply, High Demand scenario results in prices that are 20 percent, or \$0.97 per million BTU above the BPC Reference Case in 2020 and 15 percent higher by 2030 (see Figure 9).

While modeled prices vary significantly across the different scenarios, it is worth noting that four out of the six scenarios result in prices that are either at the same level as, or below, the prices in the BPC Reference Case. Modeled prices exceed the Reference Case level in only two scenarios—the Low Supply, High Demand scenario and the Low Supply, Reference Demand scenario—which both make extremely conservative assumptions about the U.S. natural gas resource base. In the Low Supply, High Demand scenario, the natural gas price is sufficiently high to support the completion of an Alaska gas pipeline, which causes a dip in the natural gas price after 2028 as additional natural gas supply is transported from isolated production in Alaska to the natural gas market in the lower 48 states.⁵³ This causes the natural gas price range across the scenarios to be smaller in 2030 than in 2025.

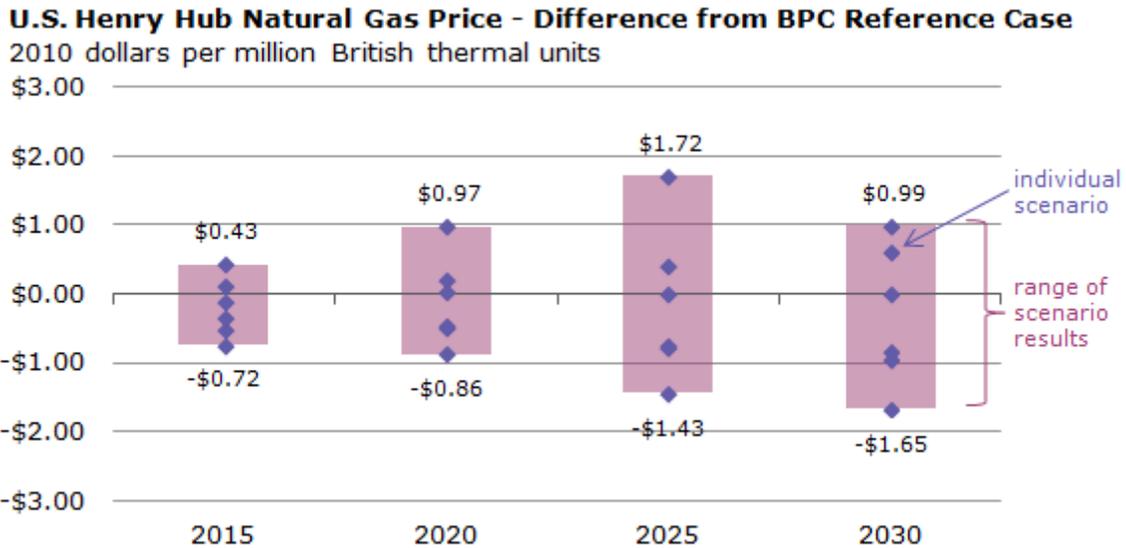


Figure 9: U.S. Henry Hub Natural Gas Price—Difference from BPC Reference Case

Modeled prices exceed the Reference Case level in only two scenarios, which both make extremely conservative assumptions about the U.S. natural gas resource base.

Key Finding 2: LNG exports are unlikely to have a large impact on domestic prices.

Entities interested in liquefying and exporting U.S. natural gas will have to take multiple factors into account when deciding whether to make the investments necessary to go forward. These factors include the domestic price of natural gas, costs for transportation and liquefaction, facility capital costs, and the price and level of demand for natural gas in target foreign markets. One of the fundamental drivers in this equation is the U.S. price of natural gas. The price of U.S. natural gas will influence LNG export levels far more than LNG exports will influence domestic prices.

It is expensive to liquefy, transport, and re-gasify natural gas. Also, the cost of building facilities is non-trivial, and cost-recovery requirements (including a reasonable profit for facility-owners) are significant. Including capital cost recovery, the liquefaction process can add between \$2-5 per mmBtu to the delivered cost of natural gas, and transporting LNG to the end destination can add more than \$1-3 per mmBtu, depending on the destination.⁵⁴ Gulf Coast terminals are most attractive, because they have pipeline access to the lowest cost natural gas and also have lower terminal construction costs. Converting existing re-gasification facilities to liquefaction facilities can provide a 30–40 percent cost savings relative to building a new LNG liquefaction facility.⁵⁵ It is relatively less expensive to ship LNG to Europe than Asia because of shorter shipping distances from the U.S. Gulf Coast to Europe. However, natural gas prices have recently been higher in Asia than in Europe because natural gas sold in Asia is typically indexed to the price of oil, while natural gas in

Europe is priced through a mixture of oil-indexed contracts as well as gas-to-gas competition.⁵⁶ Even though prices in the future are likely to be increasingly dependent on gas-to-gas competition as the international LNG market expands, prices in Asia are expected to remain higher in the future because so much of the natural gas supply there is already under previous, long-term oil-indexed contracts and because demand for natural gas in the region is growing rapidly.

Decisions to export LNG must also factor in potential LNG market competition from Africa, Australia, Canada, and the Middle East. The United States will likely not be a first mover in the global market for LNG, and entry by other countries may further depress prices in the global LNG market. For example, Australia has nine liquefaction projects that already have or are close to securing the financing needed to go forward.⁵⁷ An LNG terminal currently under construction in Canada should be operational by mid-2015, several months ahead of the only approved U.S. terminal, and the Canadian government has already approved more LNG export capacity than the United States.⁵⁸

Accounting for all of the factors listed above, BPC’s scenario analysis produces a range of estimates for future LNG exports, from a low of 2.0 bcf/d to as much as 6.4 bcf/d by 2020 (see Figure 10). While the modeling results for each scenario depict export levels achieving their maximum by 2020, the ramp-up to maximum export levels would more likely be stepwise, as forecast in the AEO2013 Reference Case. This is because it is unlikely that multiple LNG export facilities can be built at once, since each of these facilities represents a very large construction project in its own right.⁵⁹

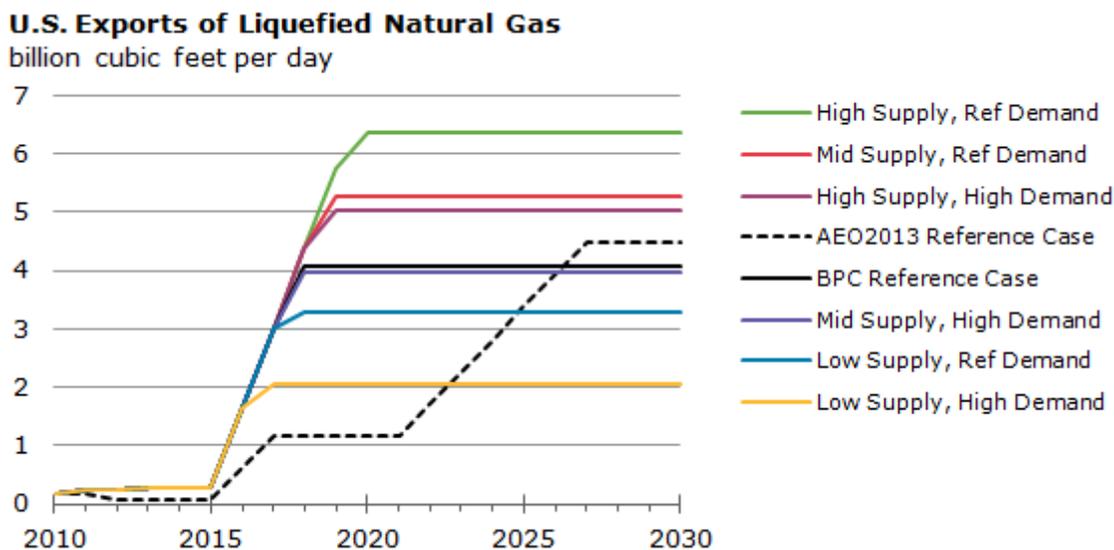


Figure 10: U.S. Exports of Liquefied Natural Gas

U.S. LNG exports depend on domestic natural gas prices. When domestic prices are low, more U.S. LNG is exported because it is more competitive in the global market. When domestic prices are high, less U.S. LNG is exported since it is relatively less competitive in the global market.

The variation in modeled LNG export levels across the different BPC scenarios corresponds to relative variations in the modeled domestic price of natural gas. For example, the High Supply, Reference Demand scenario results in the lowest domestic natural gas price and the highest level of LNG exports. Conversely, the Low Supply, High Demand scenario has the lowest level of LNG exports as a result of high domestic natural gas prices that make U.S. natural gas exports less competitive in the global LNG market.

U.S. LNG Exports Are Unlikely to Result in Large Price Impacts in the Domestic Market

The results of a series of side cases to BPC's modeling analysis that focus on the discrete impacts of LNG exports—specifically, side cases that couple LNG exports with reference level demand for natural gas—suggest that LNG exports are likely to have only modest impacts on domestic natural gas prices.

Figure 11 shows the projected volume of LNG exports under four scenarios:

- The Reference Case of the EIA's AEO2012 (BPC-NEMS Reference)
- The BPC-NEMS case based on the AEO2012 Reference Case but also including endogenous exports (BPC-NEMS Reference with Endogenous Exports)
- A modified BPC-NEMS case in which the supply assumptions have been changed to reflect an increase in the quantity of economically recoverable shale gas (BPC-NEMS High Supply Reference)
- A modified BPC-NEMS case in which an increase in the quantity of economically-recoverable shale gas has been combined with the effects of international trade feedbacks (BPC-NEMS High Supply and Endogenous Exports)
- LNG export volumes across these four modeling scenarios ranged from 2.5 bcf/d in the BPC-NEMS Reference case as well as in the BPC-NEMS High Supply Reference case to 9.5 bcf/d in the BPC-NEMS High Supply and Endogenous Exports case.⁶⁰ Export volumes in the BPC-NEMS Reference with Endogenous Exports case fell between these two extremes at 3.8 bcf/d.

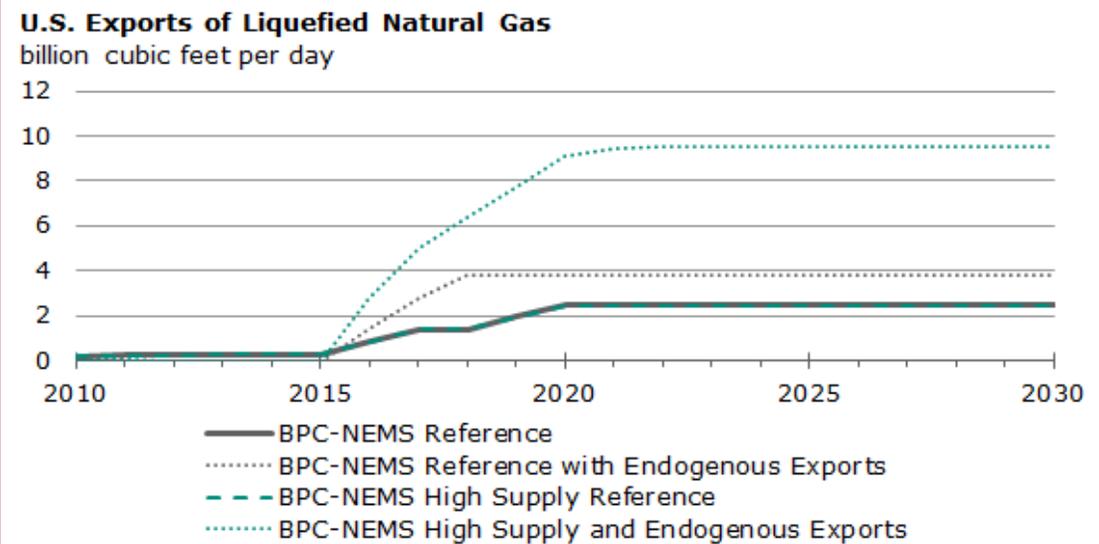


Figure 11: U.S. Exports of Liquefied Natural Gas

BPC’s analysis also examined the domestic price impacts of LNG exports. Figure 12 shows Henry Hub natural gas prices under the four export scenarios considered. Modifying the BPC-NEMS case with AEO2012 natural gas supply to allow for endogenously determined LNG exports increased domestic natural gas prices by about 2 percent, or \$0.12 per mmBtu, above the projected AEO2012 Reference Case price for 2025.

Under the BPC-NEMS case with high natural gas supply and endogenous exports, the larger natural gas resource base keeps domestic prices well below AEO2012 Reference Case levels, which in turn creates greater opportunities to cost-effectively export LNG. With endogenous LNG exports, Henry Hub gas prices for 2025 in the BPC-NEMS High Supply case rise by 9 percent or \$0.33 per mmBtu over BPC-NEMS High Supply Reference case level.

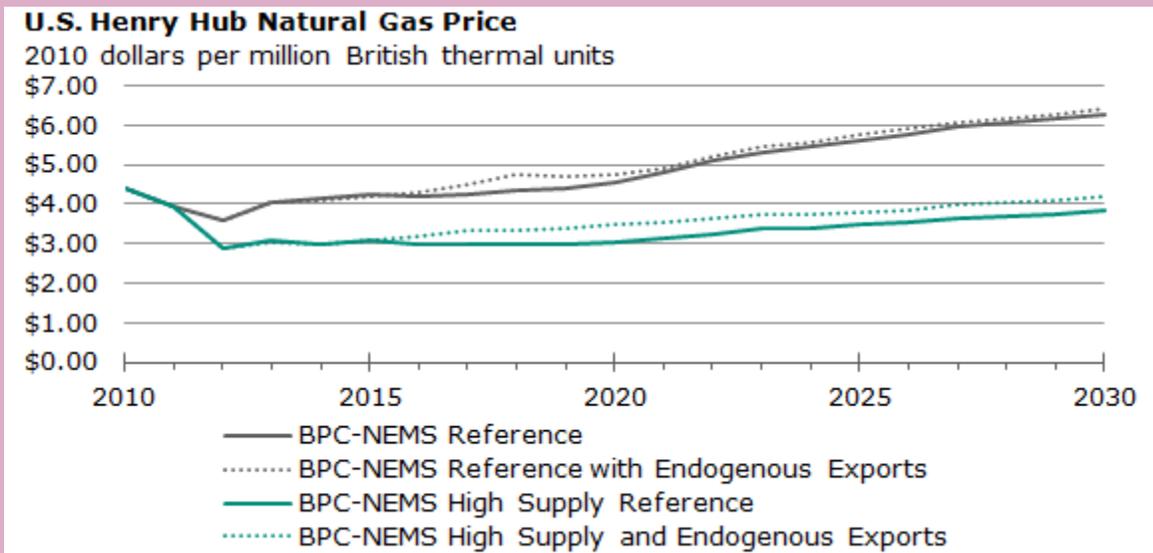


Figure 12: U.S. Henry Hub Natural Gas Price

In sum, the United States is projected to become a net exporter of natural gas between 2017 and 2021 in all of the modeled scenarios (see Figure 13). As domestic production of natural gas exceeds domestic consumption, the United States is projected to export natural gas via pipeline and as LNG.

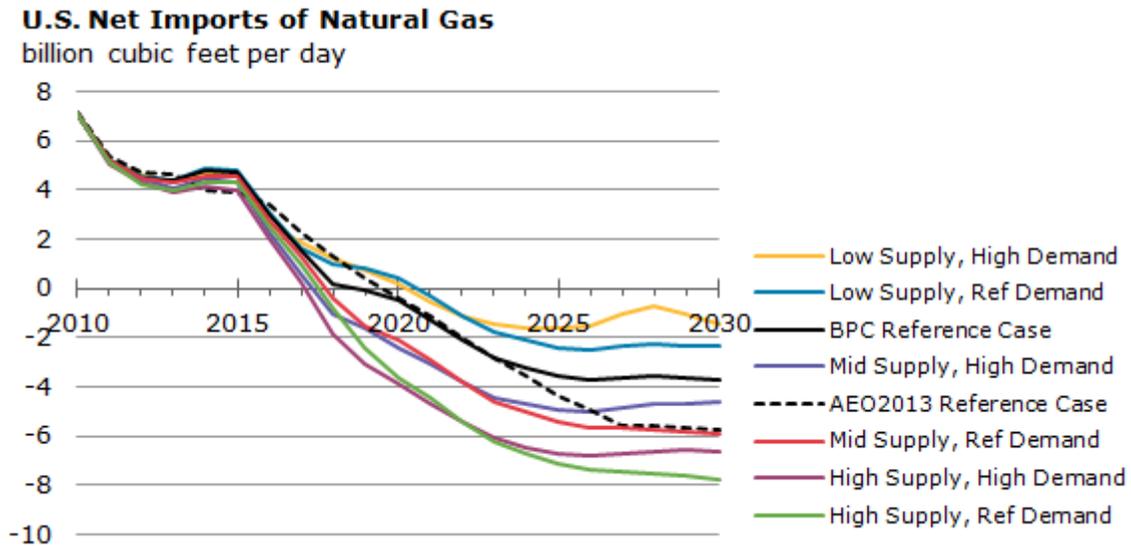


Figure 13: U.S. Net Imports of Natural Gas

The United States is projected to become a net exporter of natural gas between 2017 and 2021 in all of the modeled scenarios, as domestic production of natural gas exceeds domestic consumption.

Though media attention and policy discussions have focused on the prospects for, and impacts of, LNG exports, net pipeline exports to Mexico are increasing rapidly and are estimated to rise to 2.3–2.6 bcf/d in the Reference Demand cases and to 4.2–4.5 bcf/d in the High Demand cases by 2020. As a result, net pipeline exports to Mexico in 2030 exceed net LNG exports in four of the six scenarios (see Figure 14). In the remaining two scenarios—specifically, the Mid Supply, Reference Demand scenario and the High Supply, Reference Demand scenario—net LNG exports exceed net pipeline exports to Mexico because domestic supply exceeds domestic demand by a larger margin, which leaves more natural gas available to export as LNG. Additionally, in all of the scenarios, pipeline exports to Canada are projected to increase while pipeline imports from Canada are projected to decline, resulting in lower net imports from Canada.

U.S. Net Exports of Natural Gas, 2030

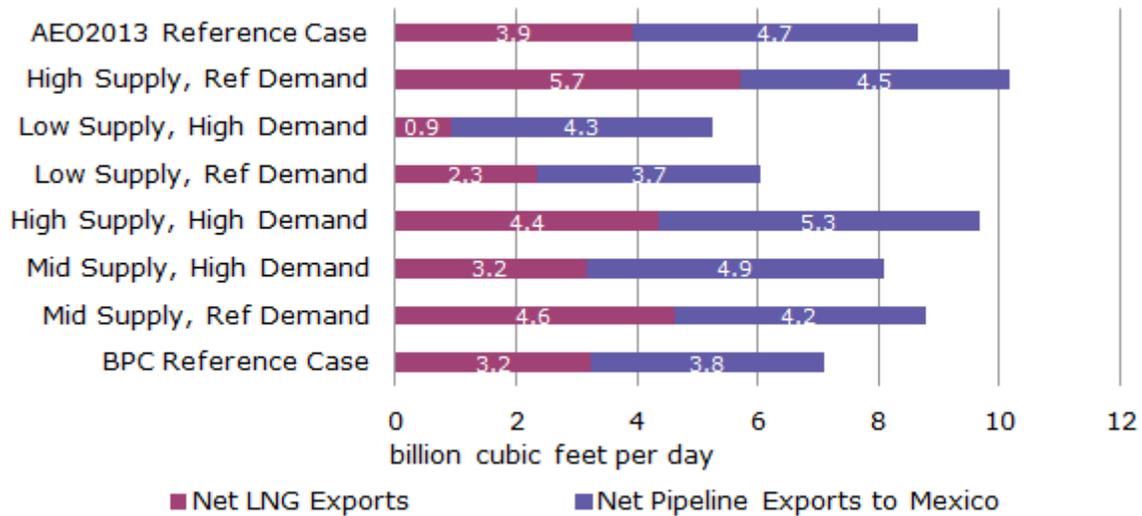


Figure 14: U.S. Net Exports of Natural Gas, 2030

Though media attention and policy discussions have focused on the prospects for, and impacts of, LNG exports, net pipeline exports to Mexico are increasing rapidly and are likely to exceed LNG export volumes. Net pipeline exports to Mexico in 2030 exceed net LNG exports in four of the six scenarios.

Key Finding 3: Increased natural gas consumption in the future will be primarily driven by overall economic growth and increased demand in the electric power and industrial sectors.

Across the scenarios modeled, overall natural gas consumption in 2020 ranged from 68 bcf/d (down 2 percent from the BPC Reference Case) to 77 bcf/d (up 11 percent from the BPC Reference Case) (see Figure 15). These differences in modeled consumption levels were driven primarily by differences in overall economic growth, electric power sector demand, and industrial demand (see Figure 16). Demand in the residential and commercial sectors was relatively unresponsive to the price of natural gas across all of the scenarios, since both these sectors use natural gas to meet space heating and cooling needs, which are mostly determined by weather.

U.S. Natural Gas Consumption

billion cubic feet per day

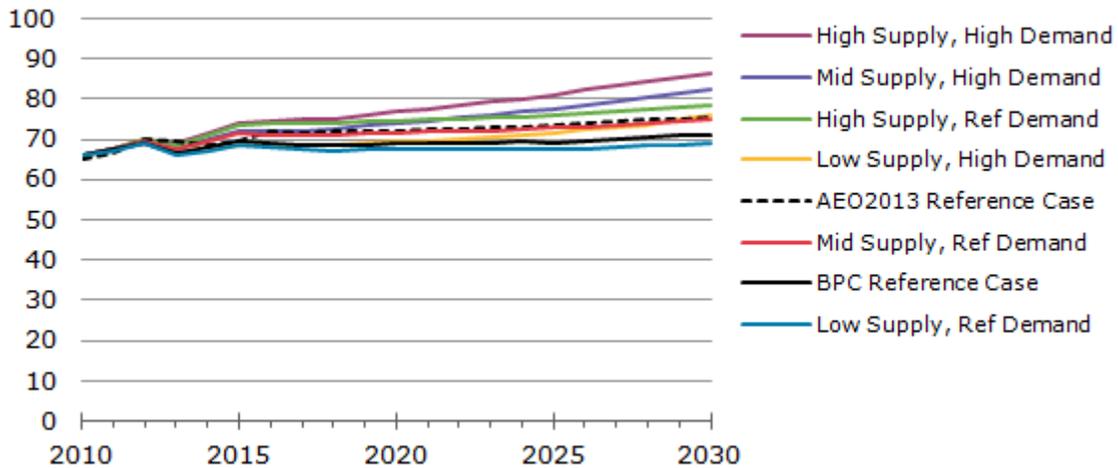


Figure 15: U.S. Natural Gas Consumption

When the model scenario features large natural gas supply and high demand, domestic natural gas consumption increases. Conversely, when supply and demand are low, consumption decreases.

When the model scenario features large natural gas supply and high demand assumptions, domestic natural gas consumption increases. Conversely, when low supply and low demand assumptions are combined, consumption decreases. Since BPC only modeled scenarios in which domestic demand for natural gas was at or above the Reference Case level, only one of the scenarios (Low Supply, Reference Demand) resulted in domestic consumption levels that were lower than in the BPC Reference Case. Overall, U.S. consumption in all of the other model scenarios was higher than in the BPC Reference Case.

U.S. Natural Gas Consumption by Sector

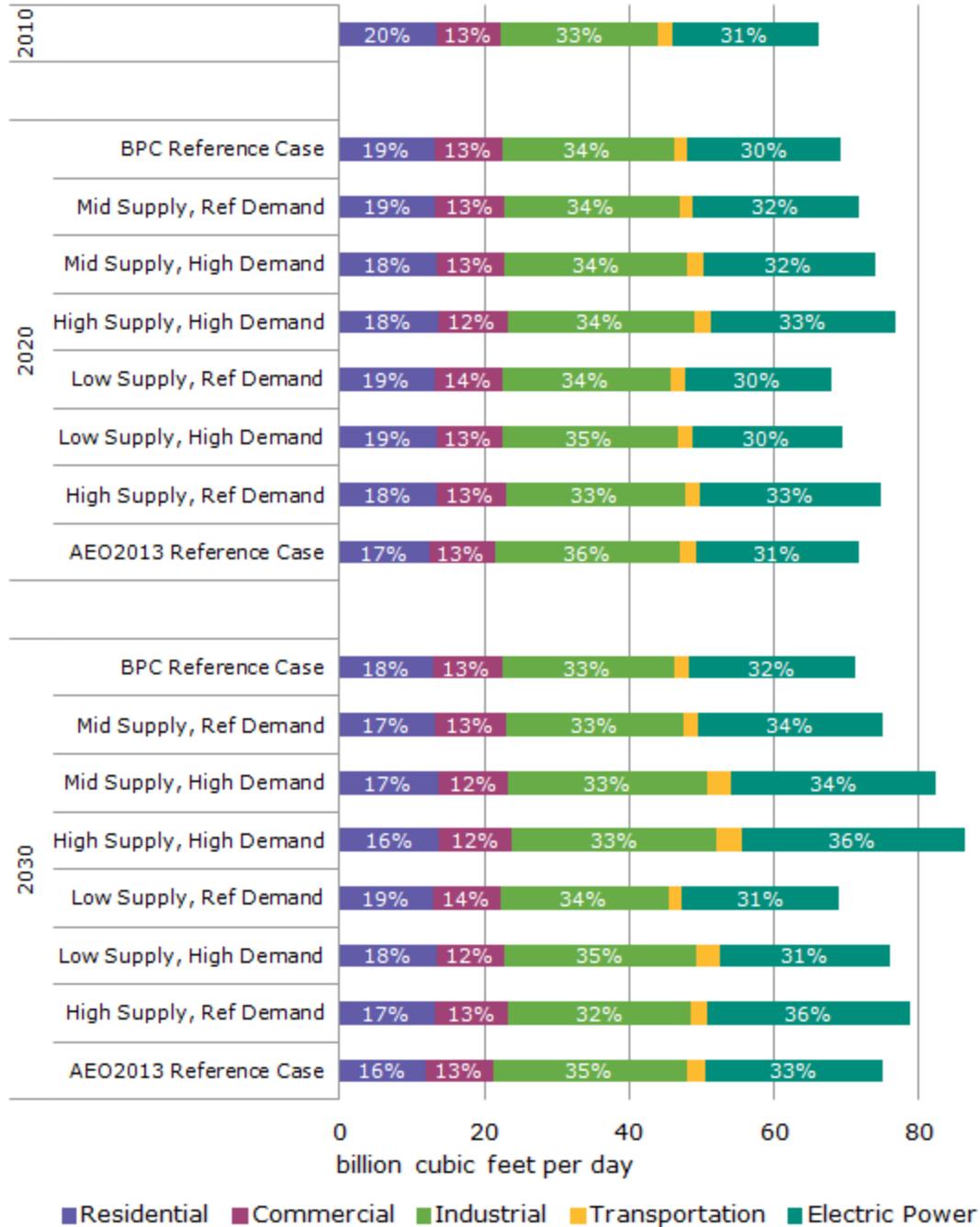


Figure 16: U.S. Natural Gas Consumption by Sector

Differences in modeled consumption levels are driven primarily by differences in overall economic growth, electric power sector demand, and industrial demand. Demand in the residential and commercial sectors was relatively unresponsive to the price of natural gas across all of the scenarios.

Key Finding 4: The industrial sector could be a major source of new demand for natural gas if projected growth in the U.S. manufacturing base is realized.

A flurry of new industrial-sector investments aimed at taking advantage of low-price natural gas and abundant NGLs has had the energy modeling community playing catch-up for the past two years. Gradually, however, these announcements have been making their way into major forecasts. EIA, in particular, made several noteworthy revisions to its industrial sector model in the AEO2013. According to EIA, “Industrial production grows by 1.7 percent per year from 2011 to 2025 in the bulk chemicals industries—which also benefit from increased production of NGLs—and by 2.8 percent per year in the primary metals industries, as compared with 1.4 percent and 1.1 percent per year, respectively, in the AEO2012 Reference Case.”⁶¹ In addition, EIA noted that most of the projected increase in industrial energy demand in the AEO2013 is the result of higher output in the manufacturing sector.

The results of the BPC analysis build on the changes made by EIA: industrial sector natural gas demand is 12 percent above BPC Reference Case levels in the AEO2013 in 2030. Similarly, industrial sector natural gas demand is 6 percent above the AEO2013 level in BPC’s High Supply, High Demand scenario. Realizing these significant increases in demand from the manufacturing sector are in turn contingent on significant new infrastructure build outs in the upstream, midstream, and downstream components of the natural gas industry: new pipelines, storage, processing, and refineries will all need to be financed, permitted, and constructed.

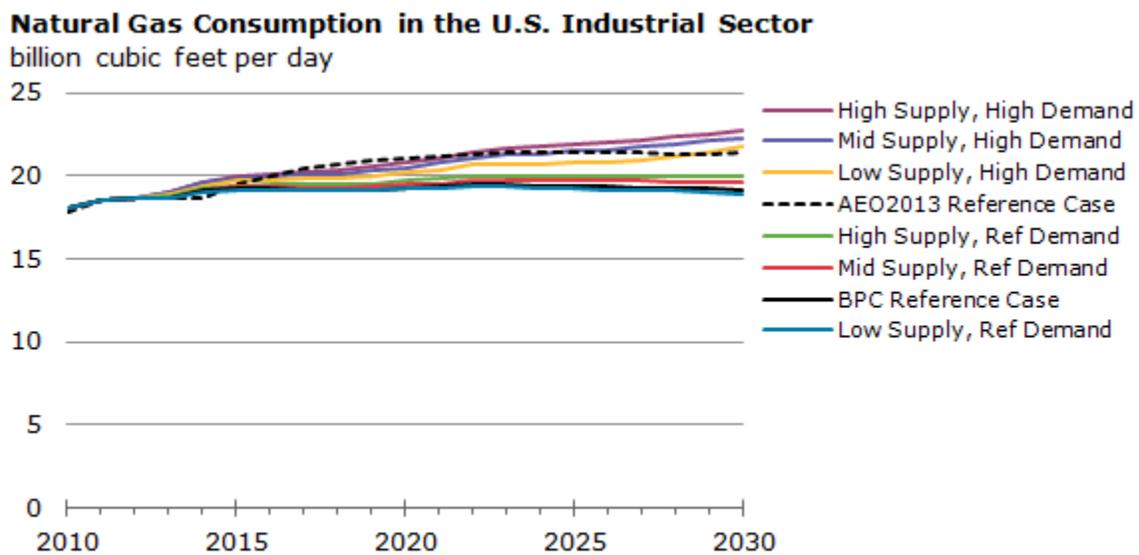


Figure 17: Natural Gas Consumption in the U.S. Industrial Sector
New industrial-sector investments result in increased natural gas demand. Industrial sector natural gas consumption in BPC’s High Supply, High Demand scenario is 18 percent above the BPC Reference Case levels in 2030.

Natural Gas Liquids

Natural gas liquids (NGLs) are hydrocarbons associated with the production of natural gas and crude oil. They include molecules such as ethane, propane, butane, isobutane, and pentane.

In response to higher crude oil prices, domestic oil and natural gas producers are increasingly targeting the liquids-rich parts of supply basins. Field production of NGLs in the United States grew from 1.8 million barrels per day in 2007 to 2.4 million barrels per day in 2012, a 35 percent increase.⁶² NGLs are extracted from the natural gas production stream in natural gas processing plants. This step is often required to meet certain fuel-quality specifications before the natural gas can enter transportation pipelines. Since domestic NGL production has already reached an all-time high, new infrastructure may be needed to avoid processing and distribution constraints in the coming years.

NGLs have many potential uses, spanning nearly all sectors of the economy. For example, NGLs can be used as inputs for petrochemical plants, burned for space heating and cooking, and blended into vehicle fuel.

Increased domestic production of natural gas will likely also result in greater domestic production of NGLs. This is a principal reason why petrochemical producers and other industrial manufacturers are looking to return to the United States.⁶³

Key Finding 5: Natural gas vehicles stand to make significant gains in market share and vehicle miles traveled by 2030.

Recent studies suggest that heavy-duty vehicle operators could achieve substantial fuel cost savings by switching to natural gas. If these cost savings are realized and current assumptions about consumer behavior are accurate, natural-gas-fueled heavy-duty trucks stand to make significant gains in market share and vehicle miles traveled by 2030.⁶⁴ In the High Demand, High Supply scenario, sales of heavy-duty natural gas trucks grow to account for 14 percent of all new heavy-duty vehicle sales and heavy-duty NGVs account for 9 percent of total heavy-duty vehicle miles traveled (see Figure 18 and Figure 19) in 2030. Despite these substantial gains, transportation-sector consumption of natural gas (at roughly 1.5 bcf/d in 2030) remains relatively small as a fraction of overall U.S. consumption, accounting for only about 2 percent of total domestic demand.

U.S. Heavy-Duty Natural Gas Vehicle Sales

percent of total heavy duty vehicle sales

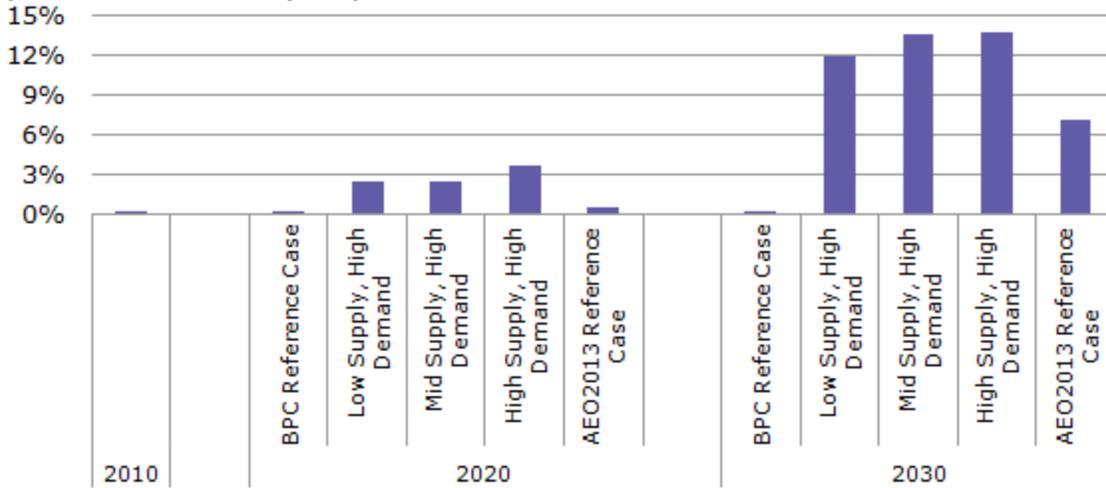


Figure 18: U.S. Heavy-Duty Natural Gas Vehicle Sales

In the High Demand, High Supply scenario, heavy-duty natural gas trucks account for 14 percent of all new heavy-duty vehicle sales in 2030.

U.S. Heavy-Duty Natural Gas Vehicle Miles Traveled

percent of total heavy duty vehicle miles traveled

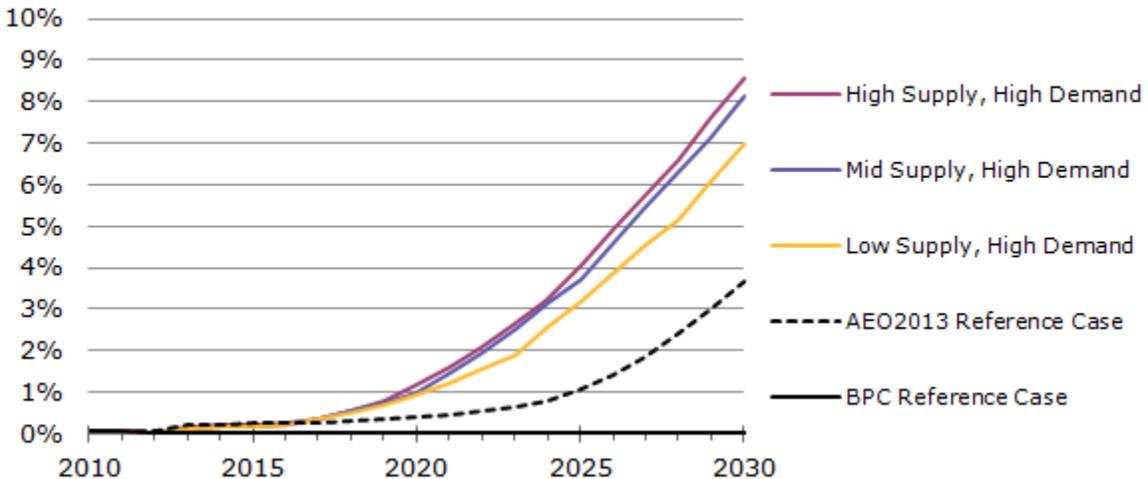


Figure 19: U.S. Heavy-Duty Natural Gas Vehicle Miles Traveled

In the High Demand, High Supply scenario, heavy-duty natural gas vehicles account for 9 percent of total heavy-duty vehicle miles traveled in 2030.

Figure 20 shows that truck consumption of natural gas is also relatively insensitive to changes in natural gas prices, ranging from 2.2 bcf/d to 2.6 bcf/d across the Low, Mid, and High Supply scenarios. This result reflects the fact that once a consumer has made an investment in an NGV, the initial investment becomes a sunk cost. Going forward the consumer will only compare the cost of natural gas fuel with its substitute (in this case,

diesel fuel). Throughout BPC’s modeling window, the cost of natural gas is significantly lower than that of diesel on an energy-equivalent basis.

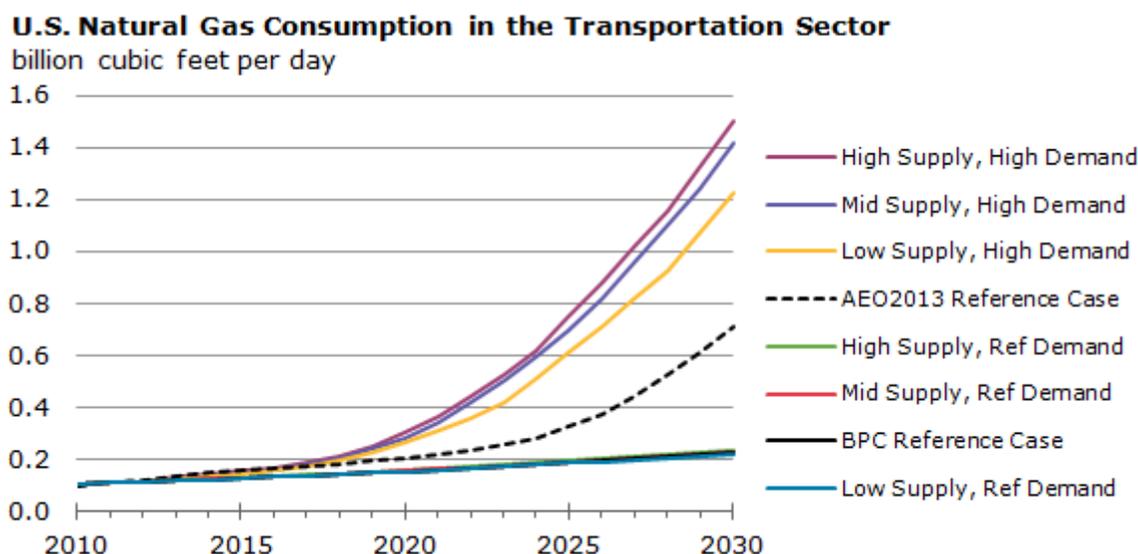


Figure 20: U.S. Natural Gas Consumption in the Transportation Sector

Transportation-sector consumption of natural gas remains relatively small as a fraction of overall consumption, accounting for only about 2 percent of total domestic demand. Truck consumption of natural gas is also relatively insensitive to changes in natural gas prices.

The Outlook for Gas-to-Liquid Fuels in the United States

Applications of the Fischer-Tropsch process, notable for its use by Sasol in South Africa to convert coal to liquid fuel, are now being contemplated in North America. This is largely because record low natural gas prices and high oil prices have combined to improve the economics of gas-to-liquid fuel processes. According to a company announcement in late 2012, Sasol has commenced design work on an \$11–\$14 billion dollar gas-to-liquid fuel project in Westlake, Louisiana. The Sasol plant would have a production capacity of 96,000 barrels per day.⁶⁵ Advocates for such investments have presented natural gas to liquid fuels as a compelling option for utilizing the huge, low-price natural gas resource base in North America to address energy security concerns. However, gas-to-liquids is an energy intensive process with a greenhouse gas emissions profile that is slightly worse than that of liquid fuels derived from conventional petroleum.⁶⁶ Also, gas-to-liquids infrastructure has very high capital costs. There are only a small number of commercially operated gas-to-liquid plants throughout the world, located in Malaysia, South Africa, and Qatar. Combined, these plants produce roughly 200,000 barrels per day of liquid fuels and petroleum—equivalent to less than 1 percent of global diesel fuel consumption.⁶⁷

Key Finding 6: In the electric power sector natural gas leads, but renewables also play a significant role

Across the scenarios modeled for this analysis, demand for natural gas from the electric power sector ranged from 20 bcf/d (about 5 percent below the BPC Reference Case) to nearly 26 bcf/d (more than 20 percent higher than the BPC Reference Case) in 2020 (see Figure 21).

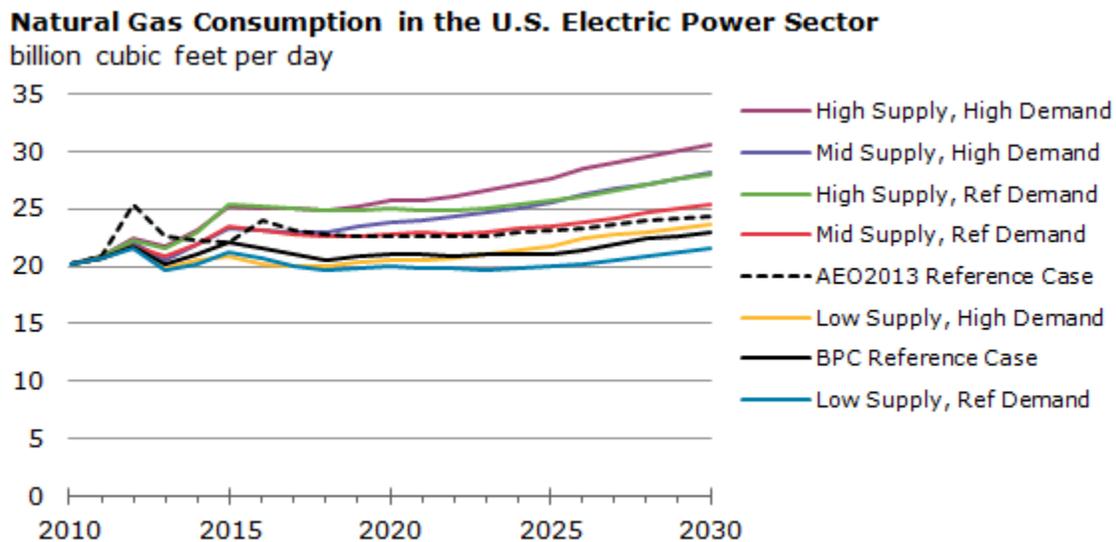


Figure 21: Natural Gas Consumption in the U.S. Electric Power Sector

In the electric power sector, natural gas use varied primarily due to changes in total electricity demand across the scenarios as well as fuel switching within the power sector.

Electricity sales grow at an average annual rate of about 0.9 percent in the Reference Demand scenarios and at an average annual rate of roughly 1.4 percent in the High Demand scenarios. Since this difference in growth rates was the only source of variation in overall electricity demand across the scenarios modeled, fuel switching within the power sector accounted for most of the difference in results for electric-sector natural gas consumption in different scenarios (see Figure 22).

U.S. Electricity Generation by Fuel

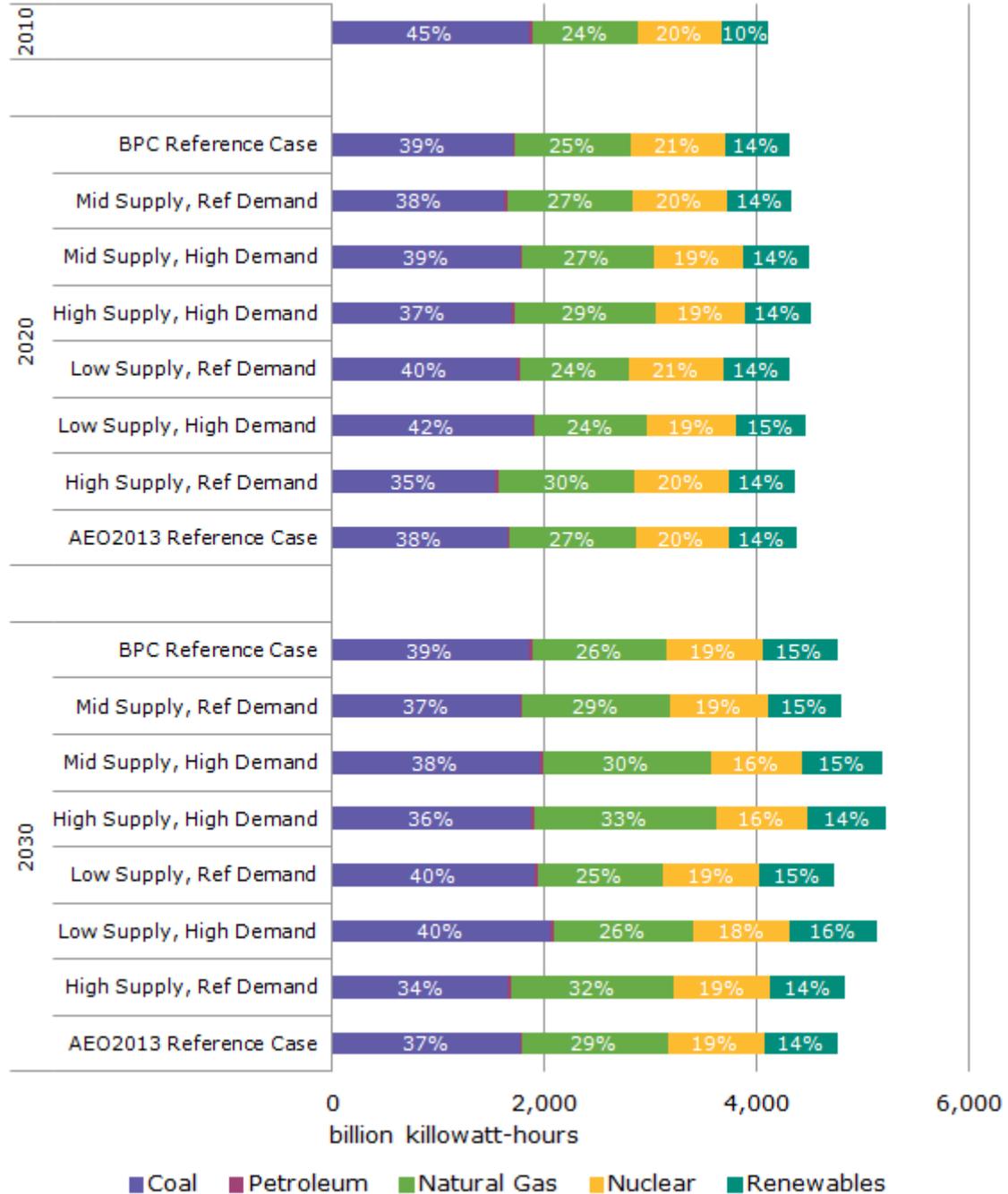


Figure 22: U.S. Electricity Generation by Fuel

When natural gas prices are low, electricity generation from natural gas is higher than in the BPC Reference Case. Conversely, when natural gas prices are high, generation from natural gas is lower. Generation from renewables is driven primarily by electricity demand, not natural gas supply.

Across BPC's model scenarios, projected natural-gas-fired electricity generation in 2020 ranges from 1,036 billion kwh to 1,330 billion kwh (equal to 24–29 percent of total electricity generation). For 2030, projected gas-fired electricity production ranges from 1,171 billion kwh to 1,727 billion kwh (representing 25–33 percent of total generation). When natural gas prices are low, such as in the High Supply, Reference Demand and High Supply, High Demand scenarios, electricity generation from natural gas is higher than in the BPC Reference Case. Generation from natural gas is lower in scenarios with high natural gas prices, such as the Low Supply, Reference Demand scenario.

Generation from hydroelectric and other renewables in 2020 ranges from 611 billion kwh to 646 billion kwh (equal to 14 percent of total generation); the range for 2030 is 683 billion kwh to 812 billion kwh (equal to 14–16 percent of total generation). In the modeling analysis, generation from renewables is driven primarily by electricity demand, not natural gas supply. Scenarios with lower electricity demand (the Reference Demand scenarios) generally resulted in estimates of renewables generation that were below the BPC Reference Case; in scenarios with higher electricity demand (the High Demand scenarios), generation from renewables was generally higher than in the BPC Reference Case.

In the modeling analysis, increased demand for electricity is largely met by additional natural gas and renewables capacity (see Figure 23). By 2030, cumulative additions of natural gas combined cycle capacity range from 36 to 91 gigawatts across the model scenarios, while additions of renewable electricity generation capacity, primarily from non-hydroelectric renewables, range from 24 to 64 gigawatts. Modeled capacity additions are very dependent on assumptions about the levelized costs of new generation resources. These cost assumptions can shift over time as technological improvements drive down the costs of particular generation resources, such as renewables.

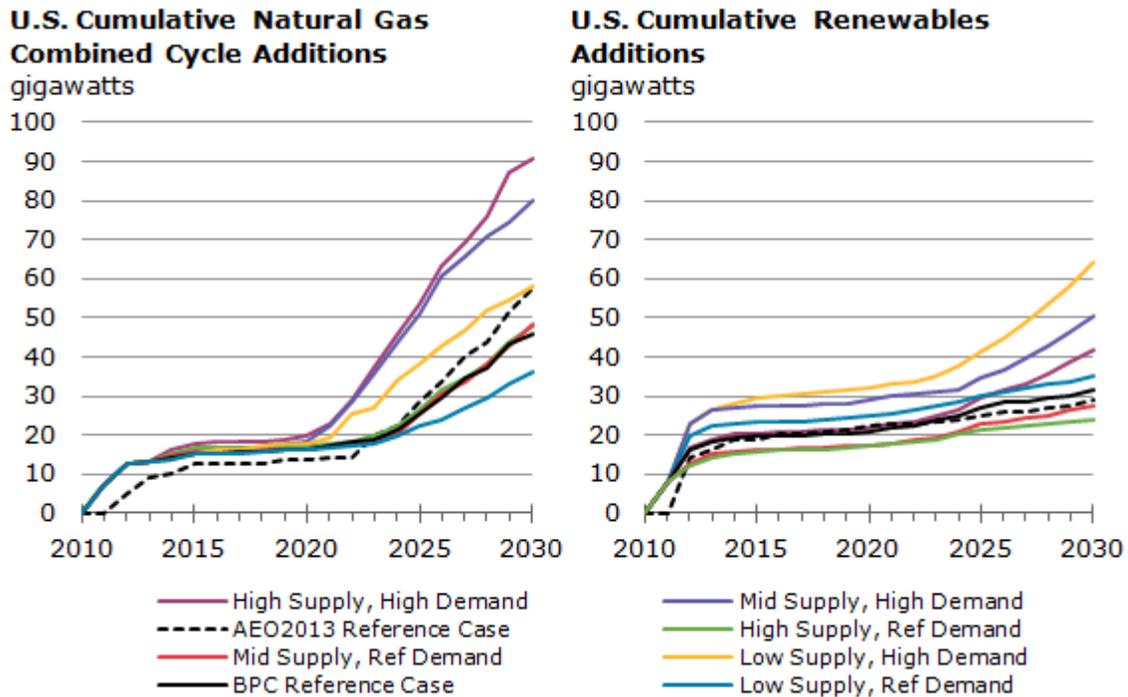


Figure 23: U.S. Cumulative Natural Gas Combined Cycle and Renewables Additions

Increased demand for electricity is largely met by additional natural gas and renewables capacity.

Even in the High Supply scenarios for natural gas, significant new renewable capacity is added along with new natural gas capacity. On average across the scenarios, for every 3 gigawatts of new natural gas capacity, the model predicts 2 gigawatts of new renewables capacity (see Figure 24). In one scenario—the Low Supply, High Demand scenario—new renewables capacity exceeds new natural gas capacity. Investments in additional natural gas and renewables capacity appear to depend more on the rate of growth in overall electricity demand than on natural gas prices—capacity additions for both renewables and natural gas were higher in the High Demand scenarios than in the scenarios with the lowest natural gas prices.

Cumulative Additions of Natural Gas Combined Cycle and Renewables Capacity by 2030

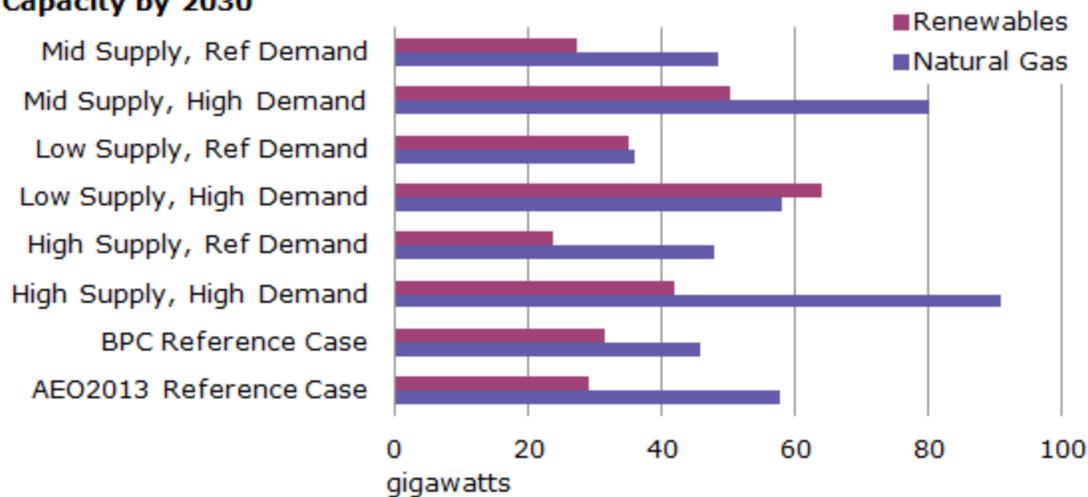


Figure 24: Cumulative Additions of Natural Gas Combined Cycle and Renewables Capacity by 2030

On average across the scenarios, for every 3 gigawatts of new natural gas capacity, the model predicts 2 gigawatts of new renewables capacity. In the Low Supply, High Demand scenario, new renewables capacity exceeds new natural gas capacity.

BPC’s modeling results show coal retirements across all of the scenarios, even in the High Demand scenarios (see Figure 25). Total coal retirements range from 25 to 60 gigawatts in 2030, with the bulk of these retirements occurring before 2018 when new environmental regulations must be met. Predicted coal retirements across the scenarios modeled were driven by two factors: overall electricity demand and available natural gas supply. The three High Demand scenarios that include higher total electricity demand resulted in less coal retirements, and the three Reference Demand scenarios had the highest levels of coal retirements. When looking at scenarios with the same demand assumptions, scenarios with low natural gas supply and higher natural gas prices result in less coal retirements as coal plants are more competitive with natural gas plants. In cases that assume abundant natural gas supply and low natural gas prices, coal plants become less competitive and more of them are retired.

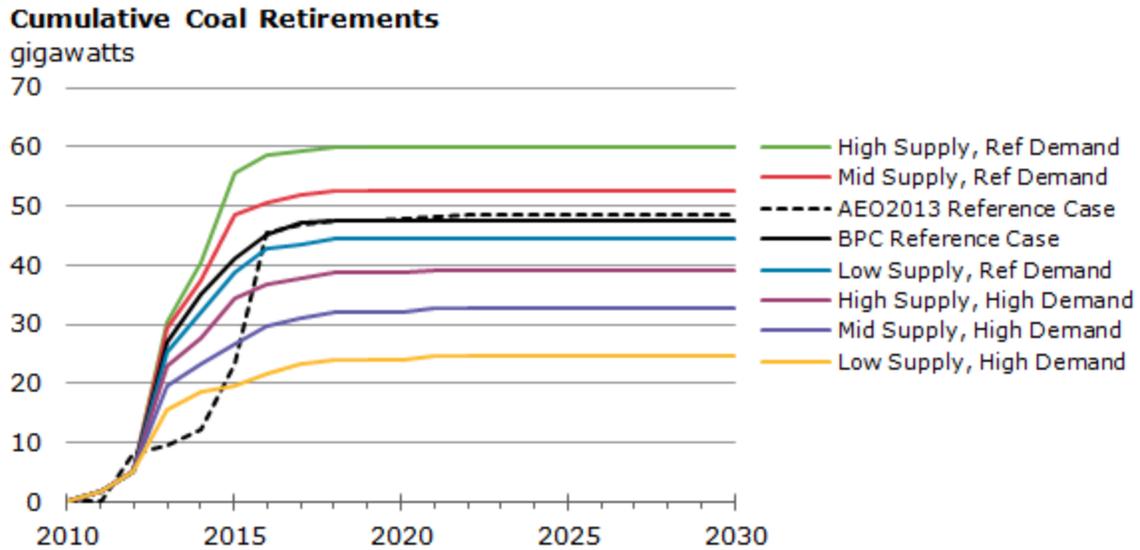


Figure 25: Cumulative Coal Retirements

In the scenarios, coal retirements are driven by two factors: overall electricity demand and available natural gas prices.

Key Finding 7: Energy-related carbon dioxide emissions are primarily driven by overall economic growth.

In BPC's modeling analysis, the primary drivers of energy-related CO₂ are economic growth and changes in total energy demand (see Figure 26). In addition, while not modeled in the scenarios considered in the BPC analysis, the rate of energy efficiency resource deployment (through both incentives and standards) will also be a key driver of future net energy demand.⁶⁸ Fuel switching in response to a greater abundance of low-cost natural gas appears to help mitigate increases in emissions as total energy demand grows.

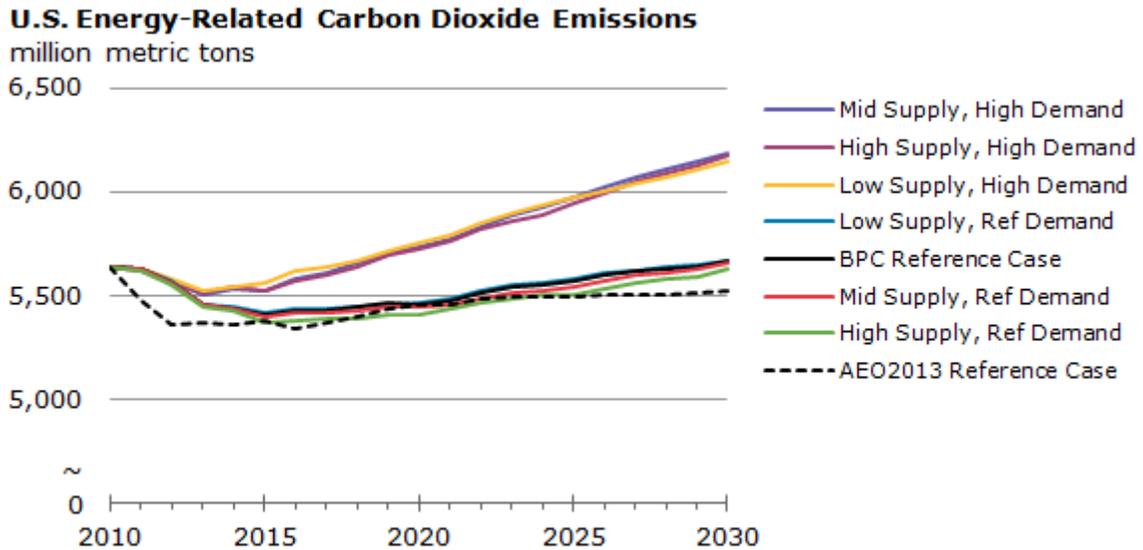


Figure 26: U.S. Energy-Related Carbon Dioxide Emissions
The primary drivers of energy-related carbon dioxide emissions are economic growth and changes in total energy demand.

The CO₂ penalty from using more natural gas is relatively small. This is particularly true if increased gas consumption is displacing the consumption of coal, a considerably more carbon-intensive fuel. In the High Supply, Reference Demand scenario, CO₂ emissions remain near the BPC Reference Case levels. By 2030, CO₂ emissions in the High Demand scenarios are about 9 percent higher than in the BPC Reference Case. This is primarily a function of higher economic growth in the High Demand scenarios.

Key Finding 8: Pricing carbon results in greater emission reductions.

The two BPC model scenarios that include a price on CO₂ emissions produce additional reductions in energy-related CO₂ emissions, with total emissions falling 12–13 percent below the corresponding reference cases by 2030 (see Figure 27). Total energy consumption declines 4 percent by 2030 in the carbon price scenarios compared with their reference cases.

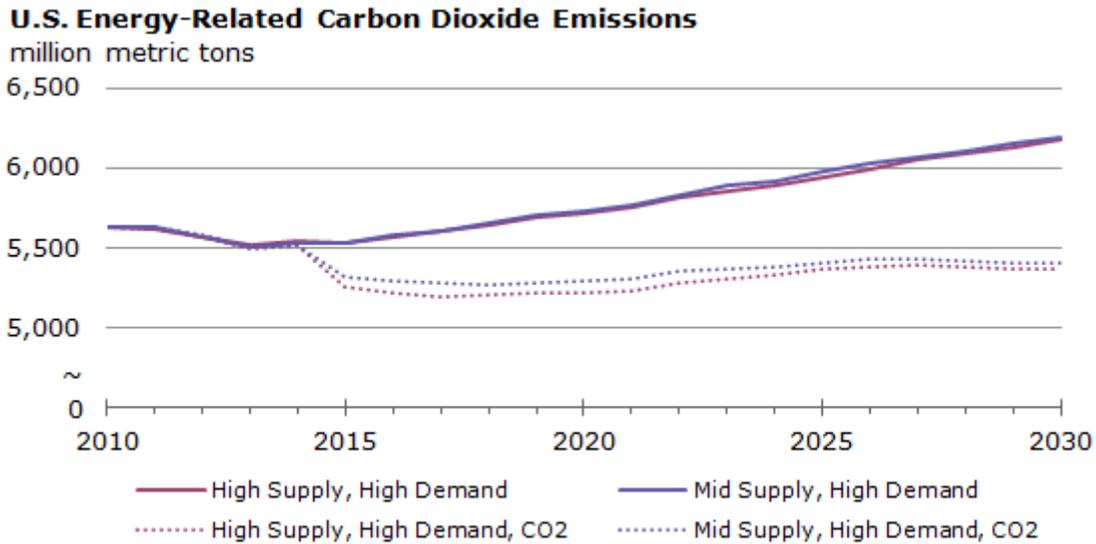


Figure 27: U.S. Energy-Related Carbon Dioxide Emissions
 The introduction of a price on carbon results in total emissions falling 12–13 percent below the corresponding reference cases by 2030.

In the modeling analysis, implementing a price on CO₂ emissions has only a limited impact on natural gas prices in the medium to long term. In 2015, Henry Hub natural gas prices are 14–19 percent higher in the CO₂ price scenarios than in the corresponding reference cases. However, this immediate price impact subsides such that natural gas prices are only 4–6 percent higher by 2020 and 1–3 percent higher by 2030. The immediate price impact around 2015 results primarily from the natural gas markets, particularly in the electric power sector, transitioning to using more natural gas to displace more carbon-intensive fuels, such as coal. Total consumption of natural gas is 4–5 percent higher in 2015 in the carbon price scenarios than in the respective reference cases, and it is 3–4 percent higher in 2020 and 2–4 percent higher in 2030. The primary driver of the increase in total natural gas consumption is the large increase in demand from the electric power sector, which is larger than the small declines in demand from the residential, commercial, and industrial sectors.

Adding a price on CO₂ emissions pushes a significant amount of coal-fired power capacity into retirement (see Figure 28). With a carbon price, cumulative coal retirements are roughly 63–74 gigawatts above reference levels by 2020. Additional coal retirements that occur after 2025 result in cumulative coal retirements of 69–87 gigawatts above reference levels in 2030.

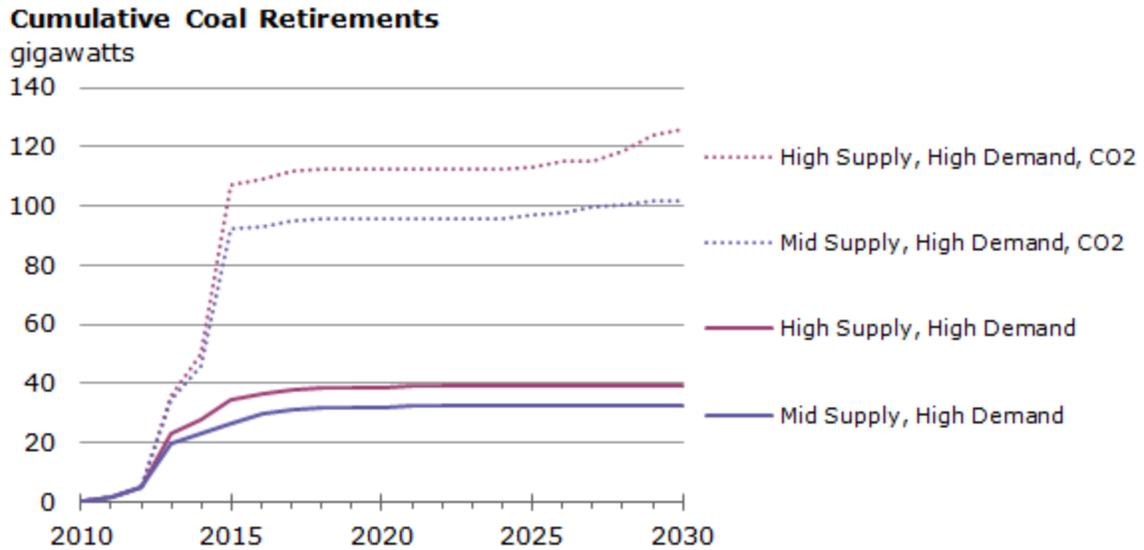


Figure 28: Cumulative Coal Retirements

Adding a price on carbon dioxide emissions pushes a significant amount of coal-fired power capacity into retirement, as the electric power sector transitions away from carbon-intensive fuels.

Most of the retired coal capacity is replaced with new natural gas capacity; new renewable capacity makes a smaller contribution even though renewable additions have the highest growth rate. This pattern is reflected in a changing generation mix (see Figure 29). Although fossil fuels still account for about 64 percent of total generation in 2020 and about 62 percent in 2030, natural gas becomes the dominant fuel in the carbon price scenarios, overtaking coal (in terms of total generation) by 2015 in the High Supply case and by 2018 in the Mid Supply case. This does not occur in any of the non-carbon-price scenarios.

U.S. Electricity Generation by Fuel

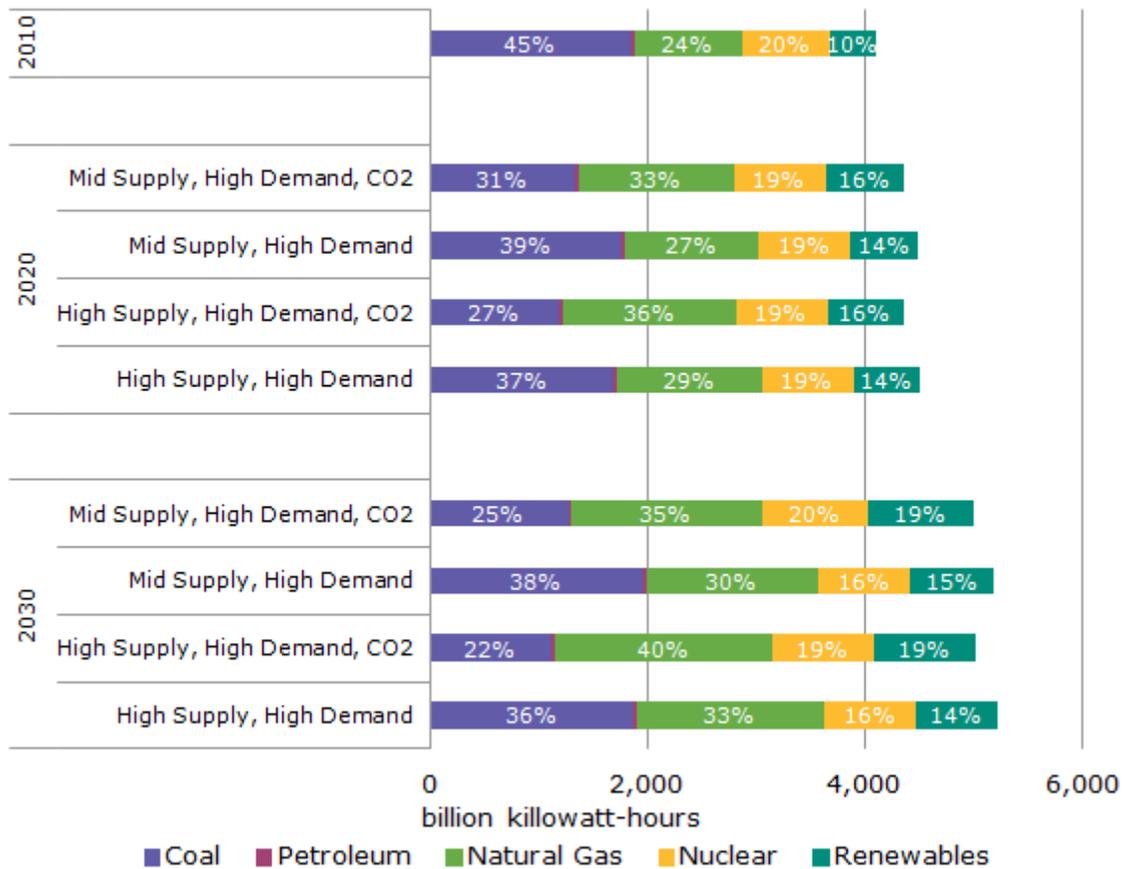


Figure 29: U.S. Electricity Generation by Fuel

In the carbon price scenarios, natural gas becomes the dominant fuel in the electric power sector by 2020. Fossil fuels retain a roughly two-thirds share of total generation.

Adding a carbon price also has an impact on natural gas exports. Because it increases domestic demand for natural gas, particularly in the electric power sector, a carbon price reduces the amount of natural gas available for export. Thus, LNG exports decline by 10–11 percent in the CO₂ price scenarios compared with the corresponding reference cases.

Conclusions

The analysis presented in this report considered the relative impact of a realistic range of supply and demand drivers that will shape future U.S. energy markets and, in particular the market for natural gas. The scenario analysis revealed that within the suite of natural gas supply and demand assumptions considered, there are ample domestic supplies of natural gas to meet future demand without significant price increases.

Similarly, the analysis shows that the United States is uniquely positioned to take advantage of the economic, environmental, and energy security benefits of the country's large natural gas resource base. Natural gas resources have the potential to create new market opportunities for expanded natural gas use in ways that will grow the economy and improve the environmental performance of the U.S. energy system, if the environmental challenges associated with natural gas development using horizontal drilling and hydraulic fracturing are addressed by industry in collaboration with state and federal regulators.

Endnotes

- ¹ For a full discussion of the role of energy productivity as a key driver of energy demand, see Bipartisan Policy Center, Strategic Energy Policy Initiative, "America's Energy Resurgence: Sustaining Success, Confronting Challenges," February 2013, p. 67. Available at <http://bipartisanpolicy.org/library/report/america%E2%80%99s-energy-resurgence-sustaining-success-confronting-challenges>.
- ² See Charles Ebinger, Kevin Massy, and Govinda Avasarala, Brookings Energy Security Initiative, Liquid Markets: Assessing the Case for U.S. Exports of Natural Gas, May 2012, available at: http://www.brookings.edu/~media/research/files/reports/2012/5/02-lng-exports-ebinger/0502_lng_exports_ebinger.pdf; Michael Levi, The Hamilton Project, "A Strategy for U.S. Natural Gas Exports," June 2012, available at: http://www.brookings.edu/~media/research/files/papers/2012/6/13-exportslevi/06_exports_levi.pdf; Kenneth Medlock III, James A. Baker III Institute for Public Policy, Rice University, U.S. LNG Exports: Truth and Consequence," August 10, 2012, available at: http://bakerinstitute.org/publications/US%20LNG%20Exports%20-%20Truth%20and%20Consequence%20Final_Aug12-1.pdf; NERA Economic Consulting, "Macroeconomic Impacts of LNG Exports from the United States," December 3, 2012, available at: http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf; and U.S. Energy Information Administration, "Effect of Increased Natural Gas Exports on Domestic Energy Markets," January 2012, available at: http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf.
- ³ A detailed overview of the NEMS model can be found at <http://www.eia.gov/oiaf/aeo/overview/index.html>.
- ⁴ U.S. Energy Information Administration, "The National Energy Modeling System: An Overview," Report Number: DOE/EIA-0581(2009). Available at: <http://www.eia.gov/oiaf/aeo/overview/index.html>.
- ⁵ Ibid.
- ⁶ U.S. Energy Information Administration, "Geology and technology drive estimates of technically recoverable resources," *Today in Energy*. Available at: <http://www.eia.gov/todayinenergy/detail.cfm?id=7190>.
- ⁷ See Bipartisan Policy Center, *Shale Gas: New Opportunities, New Challenges*, January, 2012, p. 13. Available at: <http://bipartisanpolicy.org/library/report/shale-gas-new-opportunities-new-challenges>.
- ⁸ In May 2012, the state of Vermont instituted a ban on natural gas extraction using hydraulic fracturing. Vermont is not known to possess economically recoverable shale oil or natural gas resources. See Vermont Statute Sec. 3. 29 V.S.A. § Chapter 14, Subchapter 8. Available at: <http://www.leg.state.vt.us/docs/2012/Acts/ACT152.pdf>. Individual cities, towns and counties in Colorado, Maryland, Michigan New York, Ohio, Pennsylvania, and West Virginia have adopted restrictions, moratoria, and bans on hydraulic fracturing. For examples of these actions, see Sorrell Negro, "Fracking Wars: Federal, State, and Local Conflicts over the Regulations of Natural Gas Activities," *Zoning and Planning Law Report*, 35-2. Available at: http://www.rc.com/documents/negro_frackingwars_2012.pdf. See also: Frac Tracker, "Current High Volume Horizontal Hydraulic Fracturing Drilling Bans and Moratoria in NY State." Available at: <http://www.fractracker.org/maps/ny-moratoria/>.
- ⁹ U.S. Department of the Interior, U.S. Geological Survey, "Assessment of Undiscovered Natural Gas Resources in Devonian Black Shales, Appalachian Basin, Eastern U.S.A.P. 27," Open-File Report 2005-1268. Available at: <http://pubs.usgs.gov/of/2005/1268/2005-1268.pdf>.
- ¹⁰ Terry Engelder, Ph.D., "Marcellus 2008: Report card on the breakout year for gas production in the Appalachian Basin," *Fort Worth Oil & Gas Magazine*, August 2009. Available at: <http://www3.geosc.psu.edu/~jte2/references/link155.pdf>.
- ¹¹ Potential Gas Committee, "Potential Gas Committee Reports Substantial Increase in Magnitude of U.S. Natural Gas Resource Base," April 27, 2011. Available at: <http://potentialgas.org/>.
- ¹² U.S. Department of the Interior, U.S. Geological Survey, "Assessment of Undiscovered Oil and Gas Resources of the Devonian Marcellus Shale of the Appalachian Basin Province, 2011," Fact Sheet 2011-3092, August 2011. Available at: <http://pubs.usgs.gov/fs/2011/3092/pdf/fs2011-3092.pdf>.
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- ¹⁴ National Petroleum Council, "Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources," September 15, 2011, p. 1-28. Available at: http://www.npc.org/Prudent_Development.html.
- ¹⁵ U.S. Energy Information Administration, *Annual Energy Outlook 2012*, June 2012, p. 64. Available at: <http://www.eia.gov/forecasts/aeo/pdf/0383%282012%29.pdf>.
- ¹⁶ Harry Vidas, "ICF North America Shale Resource Assessments," ICF International, April 2012.
- ¹⁷ See "Potential Gas Committee reports unprecedented increase in magnitude of U.S. natural gas resource base," Colorado School of Mines News Release, June 18, 2009. Available at: <http://www.mines.edu/Potential-Gas-Committee-reports-unprecedented-increase-in-magnitude-of-U.S.-natural-gas-resource-base>. See also: "Potential

Gas Committee Reports Substantial Increase in Magnitude of U.S. Natural Gas Resource Base," Potential Gas Committee Press Release, April 27, 2011. Available at: <http://potentialgas.org/download/pgc-press-release-april-2011.pdf>.

¹⁸ U.S. Energy Information Administration, "AEO2013 Early Release Overview," p. 5. Available at: <http://www.eia.gov/forecasts/aeo/er/pdf/0383er%282013%29.pdf>.

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²⁰ Notes: MIT estimate includes Alaska; PGC estimate may include associated gas from tight oil plays with shale gas estimate.

²¹ U.S. Energy Information Administration, "Issues in Focus: U.S. crude oil and natural gas resource uncertainty," *Annual Energy Outlook 2013*. Available at: http://www.eia.gov/forecasts/aeo/IF_all.cfm#fn110ref.

²² U.S. Energy Information Administration, *Monthly Energy Review*, March 27, 2013.

²³ Natural gas consumption in the transportation sector includes natural gas consumed in the operation of pipelines, primarily in compressors, and natural gas used as fuel in the delivery of natural gas to consumers. See U.S. Energy Information Administration, *Monthly Energy Review*, March 27, 2013; U.S. Energy Information Administration, *Annual Energy Outlook 2013 Early Release*, December 5, 2012.

²⁴ U.S. Energy Information Administration, "Table 7.2a Electricity Net Generation: Total (All Sectors)," *Monthly Energy Review*, April 2013. Available at: http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_5.pdf.

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²⁶ *Ibid*, p. 40.

²⁷ U.S. Department of Energy, "Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of April 2, 2013)," accessed April 12, 2013. Available at: http://www.fossil.energy.gov/programs/gasregulation/reports/summary_lng_applications.pdf.

²⁸ The U.S. Department of Energy commissioned NERA Economic Consulting to conduct a study "in order to gain a better understanding of how U.S. LNG exports could affect the public interest, with an emphasis on the energy and manufacturing sectors." DOE released the study for two rounds of public comment commencing on December 11, 2012, and closing on February 25, 2013. According to DOE, "Following the closing of the reply comment period, the Department of Energy will begin to act on the 15 applications on a case-by-case basis." Available at: <http://www.fossil.energy.gov/programs/gasregulation/LNGStudy.html>.

²⁹ Charles Ebinger, Kevin Massy, and Govinda Avasarala, Brookings Energy Security Initiative, "Liquid Markets: Assessing the Case for U.S. Exports of Natural Gas," May 2012. Available at: http://www.brookings.edu/~media/research/files/reports/2012/5/02-lng-exports-ebinger/0502_lng_exports_ebinger.pdf.

The study assessed recent economic analyses by the Energy Information Administration, Deloitte, ICF International, as well as two separate studies by Navigant Consulting.

³⁰ This range does not reflect the full range of price impacts found in the economic studies reviewed by Brookings. In particular, some scenarios modeled by the Energy Information Administration were not included in the Brookings summary of price impacts because the authors felt the level and pace of growth in LNG exports were not realistic. The Energy Information Administration itself included several caveats in its own analysis regarding the results of some of these scenarios.

³¹ Michael Levi, The Hamilton Project, "A Strategy for U.S. Natural Gas Exports," June 2012. Available at: http://www.brookings.edu/~media/research/files/papers/2012/6/13-exportslevi/06_exports_levi.pdf.

³² Kenneth Medlock III, James A. Baker III Institute for Public Policy, Rice University, "U.S. LNG Exports: Truth and Consequence," August 10, 2012, p. 5. Available at: http://bakerinstitute.org/publications/US%20LNG%20Exports%20-%20Truth%20and%20Consequence%20Final_Aug12-1.pdf.

³³ See NERA Economic Consulting Analysis Study. Available at: http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf.

³⁴ U.S. Department of Energy, Office of Fossil Energy, "Energy Department Releases Study on Natural Gas Exports, Invites Public Comment," December 5, 2012. Available at: <http://www.fossil.energy.gov/programs/gasregulation/LNGStudy.html>.

³⁵ NERA Economic Consulting, *Macroeconomic Impacts of LNG Exports from the United States*, December 3, 2012, p. 1-2. Available at: http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf.

³⁶ *Ibid*, p. 2.

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- ⁴¹ Ibid.
- ⁴² PIRA Energy Group, "Natural Gas Vehicles Gaining Traction," August 27, 2012, p. 5.
- ⁴³ The Energy Information Administration (EIA) implemented a number of these assumptions in the AEO2012 HD NGV Potential Case. Specifically, the HD NGV Potential Case modified incremental vehicle costs, expanded the presence of natural gas refueling infrastructure by assumption, and increased the potential market penetration for heavy-duty vehicles by assuming that vehicle owners would consider purchasing an NGV if fuel savings justified this choice over a payback distribution with a weighted average of three years. For a complete discussion of the treatment of natural gas vehicles in NEMS and of EIA's baseline assumptions on natural gas vehicles in the AEO2012, see U.S. Energy Information Administration, "Issues in Focus, 6. Heavy-duty natural gas vehicles." Available at: http://www.eia.gov/forecasts/archive/aeo12/IF_all.cfm#heavynatgas.
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