DYNAMIC DELIVERY

America's Evolving Oil and Natural Gas Transportation Infrastructure

CHAPTER ONE – SUPPLY AND DEMAND

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Chapter One

SUPPLY AND DEMAND

I. INTRODUCTION

The United States is now the leading producer of primary energy in the world due in large part to higher shale oil and natural gas production. Total U.S. liquids production increased from 6.8 million barrels per day (MMB/D) in 2008 to 15.2 MMB/D in 2018, and the United States regained its status as the world's largest crude oil producer. Over about the same period, U.S. natural gas production has also surged—from 53.2 billion cubic feet per day (BCF/D) in 2006 to 89.7 BCF/D in 2018—making the United States the world's largest natural gas producer.

The U.S. oil and natural gas story is not just about volume growth—but changes in geographic location as well. Mature producing areas experienced rapid increases in production, most notably the Permian Basin of West Texas and Southeast New Mexico and the Appalachian Basin, including Pennsylvania, West Virginia, and Ohio. In addition, new areas of major crude oil production have developed, such as the Eagle Ford formation in South Texas. The rapid and dramatic change in production volumes in new and revitalized areas has driven capacity growth of existing infrastructure and created needs for new infrastructure.

This chapter is divided into two sections: supply and demand. Each section starts with a brief description of supply and demand trends to provide historical context. The major focus is on assessing a range of outlooks for changes in supply then demand, and the factors that shape those trends through 2040. Forecasts from the U.S. Energy Information Administration (EIA), International Energy Agency (IEA), IHS Markit, Rystad Energy, Wood Mackenzie, BP, Organization of Petroleum Exporting Countries (OPEC), and Rhodium Group/Columbia University's Center on Global Energy Policy include outcomes in low-carbon policy scenarios. This information provides the foundation for understanding the future changes and issues for infrastructure that connect production to consumption.

The supply section presents production forecasts that project oil production ranging from a high of 20 MMB/D to a low of 7 MMB/D in 2040, and natural gas outlooks to 2040 that range from a high of 137 BCF/D to a low of 83 BCF/D.

Regional forecasts show that the Permian and Appalachian Basins are expected to be the major engines of production growth. Recent oil and natural gas production is located in the U.S. heartland east of the Rocky Mountains and west of the Appalachian Mountains. However, the majority of U.S. population, and therefore demand for energy, reside on the coasts, west of the Rockies and east and south of the Appalachians. Initially, existing infrastructure including pipelines, rail, marine transport, and trucking were used to connect new or expanding sources of supply with demand. Eventually, new pipelines, rail cars, barges, and trucks were required and will be required into the future.

The demand section provides a brief synopsis of world oil demand, issues that affect U.S. refining and consumption, then reviews the continuously evolving demand for both refinery feedstocks and refined products in the United States by analyzing their historical consumption patterns and trade flows and comparing those patterns to projections for the future. Further, to provide a better understanding of the entire market, the study also analyzed imports, exports, and possible substitutes, such as renewables, for certain feedstocks, refined products, and power generation sources. From these analyses, the chapter highlights potential structural shifts in consumption that could have impacts on the logistical infrastructure in the United States.

Demand is reviewed at certain points in the value chain including: (1) U.S. refinery crude oil feedstock requirements; (2) U.S. consumption of refined products, primarily focused on transportation fuels such as gasoline, jet fuel, diesel, and residual fuel oil; (3) U.S. consumption of natural gas; and (4) U.S. consumption of natural gas liquids (NGLs).

Petroleum liquids and natural gas are the top two sources of U.S. primary energy consumption. Even in low-carbon scenarios discussed in this chapter, they remain the top two sources of primary energy consumption through at least 2040.

Most forecasts show U.S. petroleum liquids demand as stable or slightly reduced due to increased engine efficiency and alternative fuel vehicles' market share increase. The IEA, World Energy Outlook (WEO) Sustainable Development Scenario (SDS)[1] shows a substantial reduction of liquids demand in the transportation sector. But there is a shift within the liquids demand mix as gasoline consumption decreases and distillates (commonly known as diesel, heating oil, and jet fuel) are forecast to remain stable or increase through 2040 as economic growth and air travel increase. Assuming minimal change in the current capacity, processing configurations, and utilization of U.S. refineries, net exports of refined products will increase.

Due to the shale revolution, the increased availability of feedstock and low energy costs have also led to growth in the U.S. petrochemical industry. A large part of this incremental growth in petrochemicals is destined for export.

Forecasts show natural gas demand rising throughout the study period except for the IEA SDS, which shows that total primary energy demand for natural gas falls but still comprises 32% of U.S. primary energy demand in 2040. In 2018, natural gas became the leading source of U.S. power generation, displacing coal. The drivers were economic and environmental. The benefits to consumers are lower power bills and a reduction in carbon dioxide (CO_2) emissions. The single largest driver for the reduction was the displacement of higher-carbon fuels by natural gas in power generation, followed by the addition of renewables and efficiency gains.

In addition to U.S. demand, world demand for oil and natural gas is rising. In 2018, the United States exported crude oil, natural gas (through both pipelines and liquefied natural gas [LNG] export terminals), NGLs, and finished products such as gasoline. The United States still imports crude oil to optimize the inputs to refineries and natural gas in cross border trades with Canada. While a net importer of petroleum liquids in 2018, some forecasts show the United States as a net exporter by 2020. U.S. LNG is shipped to Latin America, Europe, and Asia.

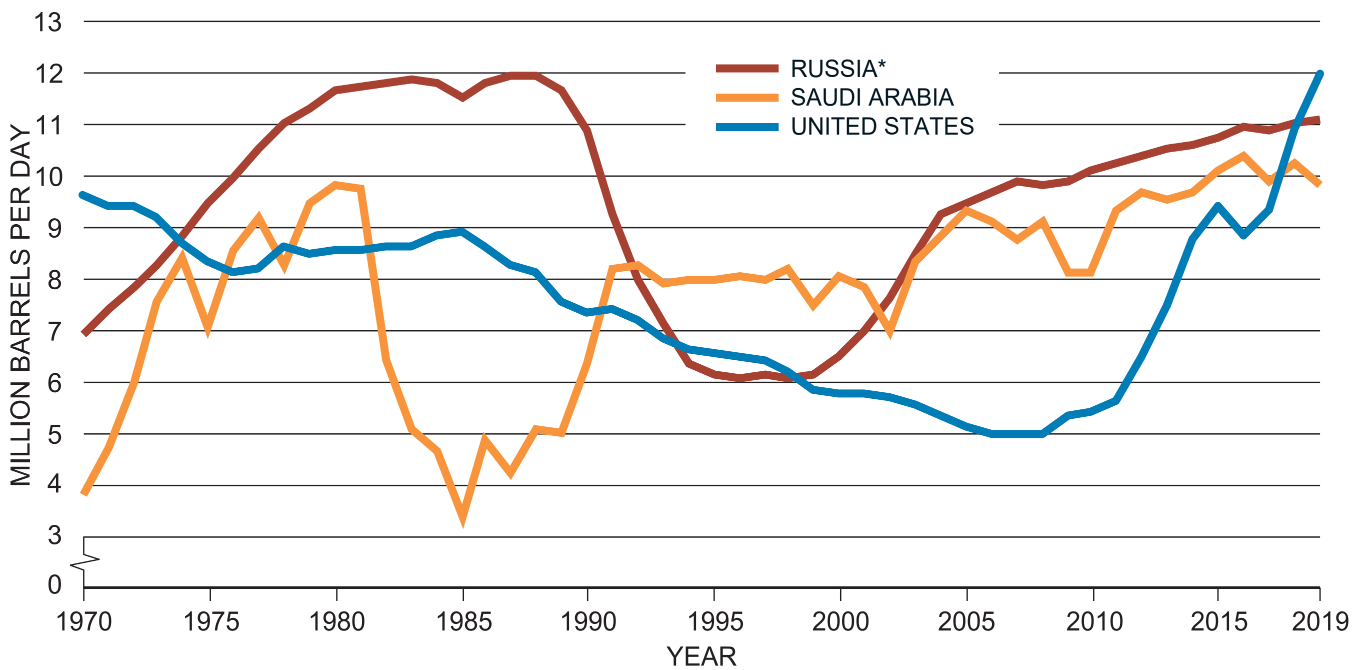
This chapter looks at future projections of demand under carbon-emission constraints and carbon taxation policies. The carbon-constrained and carbon taxation scenarios do not represent specific recommendations for future domestic policy. These scenarios were selected to provide a framework for considering how oil and natural gas demand could change under policies of varying stringency and scope.

II. SUPPLY

A. Historical Trends

After hitting a 62-year low in 2008, crude oil production increased 118% by 2018—a volume gain of 5.9 MMB/D. By late 2018 the United States was, once again, the largest crude oil producer in the world, as shown in Figure 1-1. U.S. growth alone since 2008 exceeds the total amount of

1 This outlook assumes global greenhouse gas emissions peak by 2020 and then decline rapidly. It is further defined in Section III. Demand, Subsection B. Outlooks Reviewed.



Sources: IHS Markit, EIA *International Energy Statistics,* and International Energy Agency; 2019 figures are IHS Markit May 2019 projections. 2019 is January-June average. Includes crude oil and condensate.
*1970-1990 figures are for Soviet Union; 1991 onward is Russia only.

Figure 1-1. *Crude Oil Production from 1970 to 2019 for the United States, Russia, and Saudi Arabia*

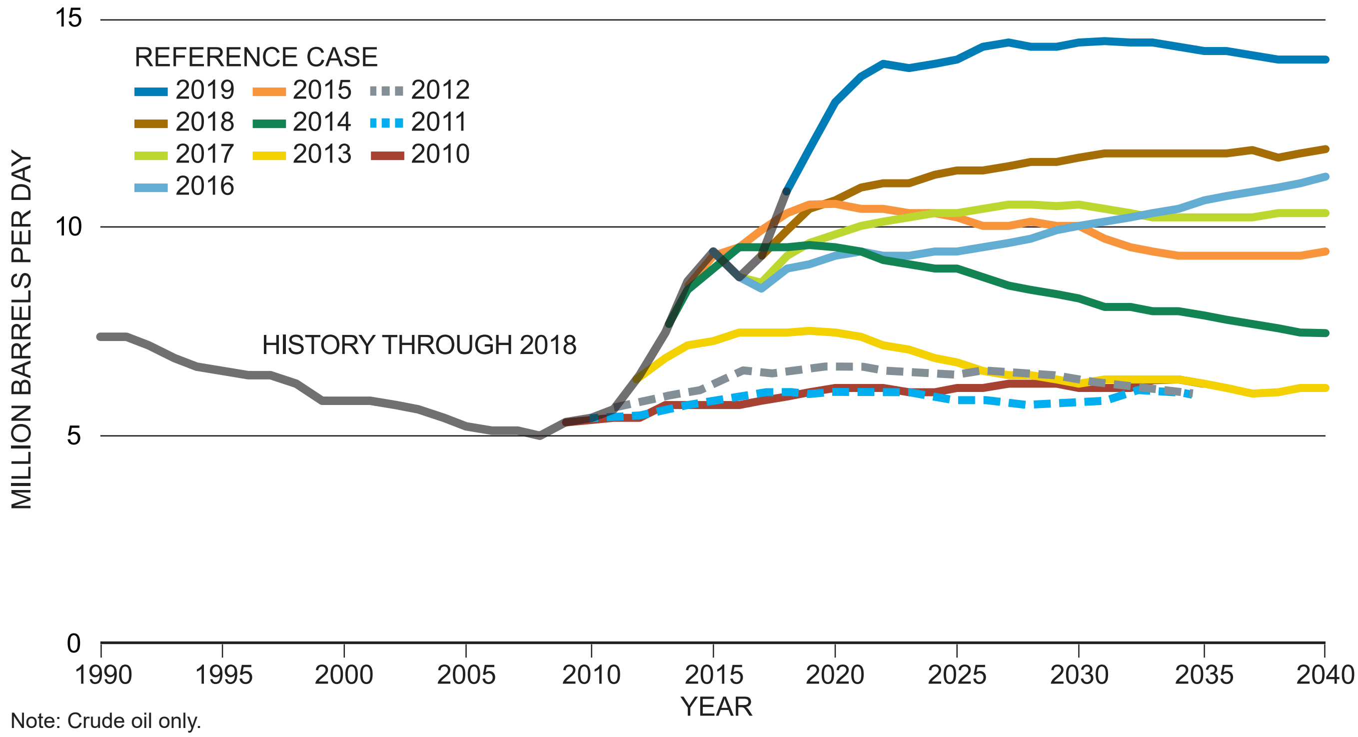
production from any single country apart from Russia and Saudi Arabia. Total U.S. liquids production increased from 6.8 MMB/D in 2008 to 15.2 MMB/D in 2018. Growth continued in 2019 as second quarter output of crude oil and NGLs reached 12 MMB/D and 4.8 MMB/D, respectively, for total liquids output of 16.8 MMB/D.

The magnitude of annual changes in crude oil production—up and down—is also unprecedented. From 1989 to 2008, the annual average change in U.S. crude oil production was a decline of 157,000 B/D. But U.S. liquids production grew 8.4 MMB/D from 2008 to 2018—an unprecedented increase in the history of the oil industry. From 2009 to 2018, the annual average change was an increase of 590,000 B/D—with several years above 1 MMB/D. This increase was in spite of 2016, the largest one year drop in U.S. history in response to lower oil industry spending following the oil price collapse of 2014 to 2016.

It was not until the early 2010s that the great revival of U.S. crude oil production was broadly recognized. Expectations for U.S. production have increased nearly every year this decade—and with good reason. Actual annual growth often exceeded projections made earlier the same year. Figure 1-2 shows the EIA's long-term projections made each year from 2010 to 2019 for U.S. crude oil production.

The story is not limited to oil. Natural gas production rose from 53.2 BCF/D in 2006 to 89.7 BCF/D in 2018. The United States overtook Russia in 2012 and has continued as the world's largest natural gas producer (Figure 1-3). In 2017, the United States became a net natural gas exporter.

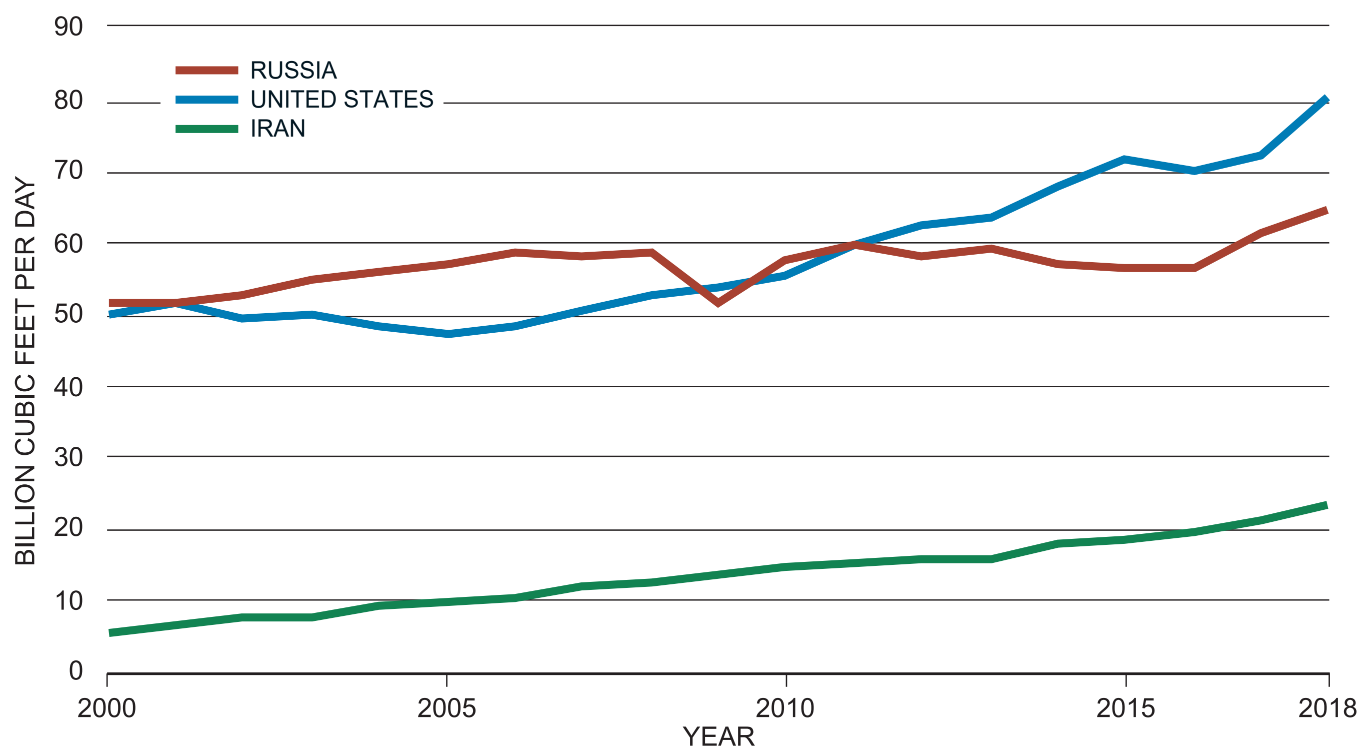
NGLs—which are principally ethane, propane, butane, and natural gasoline (also called C5+ naphtha)—are part of the growth story as well. NGLs are a byproduct of "wet" natural gas production and used as petrochemical feedstocks and for heating and gasoline blending. Wellhead production of total NGLs was flat from 1990 through 2008, after which it more than doubled (from 1.78 MMB/D to 4.35 MMB/D) commensurate



Note: Crude oil only.

Source: EIA, *Annual Energy Outlooks.*

Figure 1-2. *Long-Term EIA Outlooks for U.S. Crude Oil Production Since 2010*



Source: 2018 *BP Statistical Review of World Energy*.

Figure 1-3. *Top Three Natural Gas Producing Countries* with growth in natural gas production at the onset of the great revival of U.S. natural gas and then oil production.

Finding: U.S. growth in liquids production since 2008 (crude oil and natural gas liquids) is unprecedented in the history of the industry. The United States is once again the largest producer in the world of crude oil and NGLs.

Finding: U.S. natural gas production began an upward climb in 2006 and by 2012 the United States became the largest natural gas producer in the world when it overtook Russia.

Finding: The United States has become the largest producer of both oil and natural gas in the world.

U.S. oil production growth has been led by tight oil development in the Permian Basin of West Texas and Southeast New Mexico and new areas of major U.S. crude oil production, such as the Eagle Ford formation in South Texas (Figure 1-4). Growth in natural gas supply has been propelled by development in the Appalachian Basin—namely the Marcellus and Utica formations in Pennsylvania, West Virginia, and Ohio—and from increased associated natural gas production, which is natural gas that is coproduced with oil.

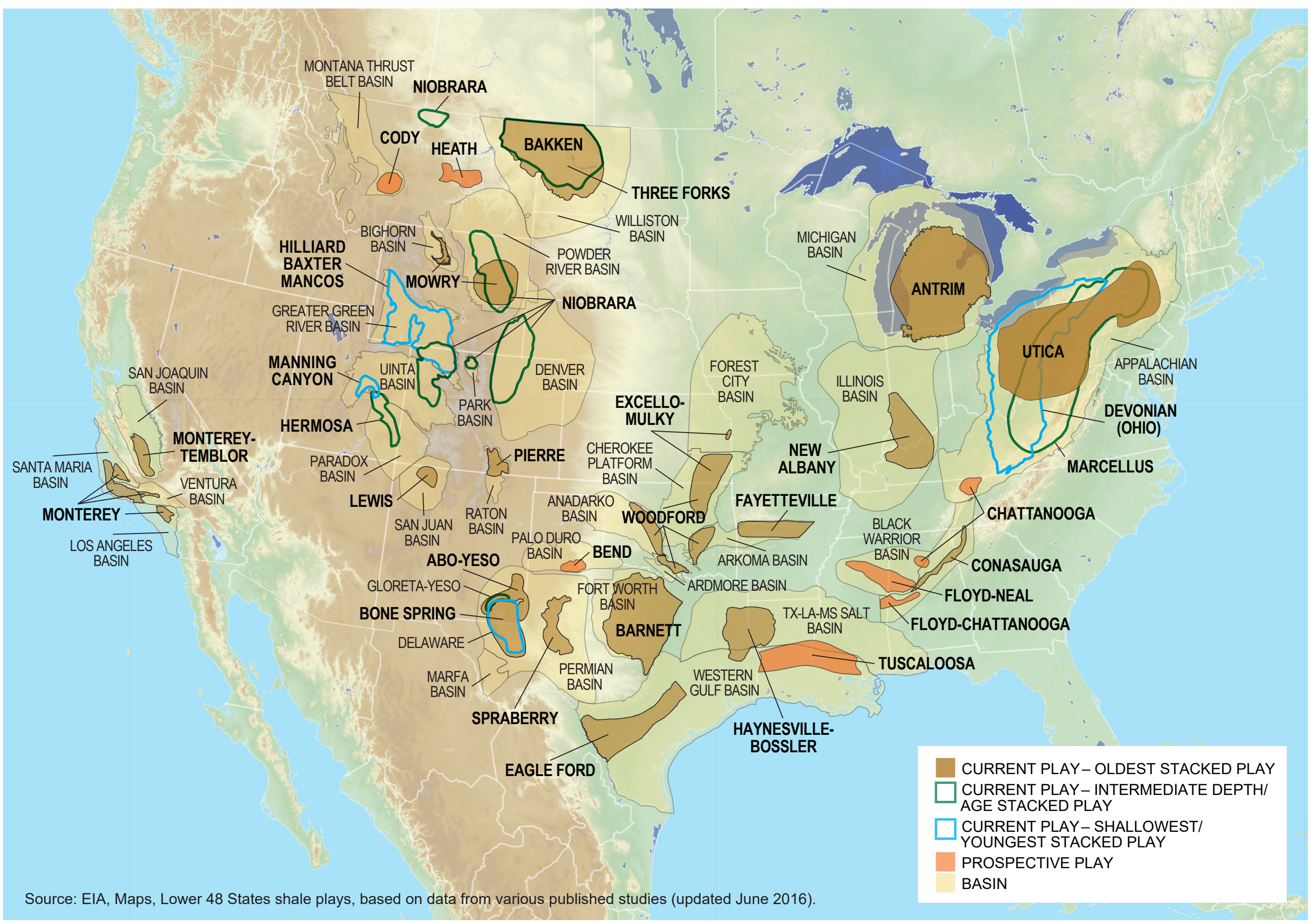


Figure 1-4. *U.S. Crude Oil and Natural Gas Production Growth is Led by Shale Plays in the Permian Basin (Texas/New Mexico), the Bakken (North Dakota), Eagle Ford (Texas), and the Appalachian Basin (Pennsylvania, Ohio, West Virginia)*

Finding: The story is not just about volume growth—but geography as production grew in rejuvenated and new areas across the country.

B. Factors That Shape Oil and Natural Gas Production

Will growth in U.S. oil, natural gas, and NGLs production continue? There is no way to accurately predict production volumes, especially for the distant future. But we can identify the factors that influence production trends in order to appreciate the drivers of supply and the degree of uncertainty about future production volumes.

- **A resource base and access to it.** Commercial scale oil and natural gas production can only take place where such resources exist in adequate volumes and companies have access to develop the resources. Identifying where commercial production can take place comes with risk. There is no certainty about production volumes until wells are drilled and production begins.

- **Crude oil and natural gas prices and cost of finding and development.** Assuming an adequate and accessible resource base, the price that producers plan to receive for what they produce, as well as the cost of finding and developing oil and natural gas, are the most fundamental elements driving production trends. The difference between these two variables—revenue versus cost—and how they compare to other investment options drives the attractiveness of upstream investment.

- **Technology.** Technology to produce oil and natural gas evolves—it is not static. As technology advances, so do the frontiers of production. For example, advances in well construction and completion are behind the growth of tight oil production in the United States. (See text box titled "Unconventional Oil, Tight Oil, and Shale Gas.")

- **Access to capital.** The oil and natural gas industry is capital intensive. According to IHS Markit, annual upstream[2] spending in recent years in the North American (United States and Canada) upstream industry has ranged from $330 billion in 2014 to $95 billion in 2016. Spending in 2018 was $154 billion. Access to capital—internally within a company or from external sources—is essential.

- **Market access.** Successful oil and natural gas development requires access to markets—domestic and international. This requires transportation—most often by pipeline, but also by rail, truck, and marine vessel. The degree and nature of market access is a key variable in the price that producers receive for oil and natural gas deliveries. A common implicit or explicit assumption in many long-term production outlooks is generally unfettered global trade in oil and natural gas.

- **Government policy, including fiscal and regulatory regimes.** Policy at local, national, and international levels is an overarching influence. Policy can impact each of the fundamental factors that shape oil and natural gas production trends.

1. Supply Outlooks Used in This Study

U.S. crude oil, natural gas, and NGLs production outlooks to 2040 were collected from a number of sources for this study. Following are descriptions of the production outlooks collected, the type of production, and the geography covered (national and/or subnational). Historical crude oil, natural gas, and NGL production data from EIA is included in outlook graphs.[3]

- **EIA Reference Case:**[4] crude oil, natural gas, and NGLs at the national and subnational levels. This case assumes "that current laws and regulations that affect the energy sector, including laws that have end dates, are unchanged throughout the projection period."

2 Upstream refers to oil and natural gas exploration, development, and production.

3 U.S. Energy Information Administration, Crude Oil Production: Petroleum & Other Liquids data; Natural gas and NGL production: Natural Gas data.

4 U.S. Energy Information Administration, *Annual Energy Outlook 2019*, p. 5, https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

UNCONVENTIONAL OIL, TIGHT OIL, AND SHALE GAS

Unconventional oil, tight oil, and shale oil are often used interchangeably to describe the driver behind the great revival of U.S. crude oil production since 2008. Each of these terms are described as follows:

- Unconventional has the broadest meaning. It was first applied to low-permeability (tight) natural gas accumulations lacking a traditional structural or stratigraphic trap. The word then began to be applied to heavy and extra heavy oil accumulations that had no traditional trap and required special extraction and/or upgrading techniques because of the highly viscous nature of the hydrocarbon. Then shale gas and subsequently shale oil were added to unconventionals. They are not limited to traditional structural or stratigraphic traps and also require different techniques to produce—long horizontal wells with multiple hydraulic fracture stimulations.

- Tight oil is a subset of unconventional. It includes oil contained within the shale or carbonate layers that are the source of the oil or are in close proximity to the oil source rocks. The rocks have low porosity and low permeability, and contain oil over extensive areas, with no or limited structural trapping. Two important features of tight oil development are the high rates at which it is initially produced and the rapid decline in production during the first year of production compared to conventional oil development. The high decline rate stimulates drilling activity to offset the decline from existing producing wells. This is why U.S. crude oil production growth has recorded both the largest annual gain in the past decade and the largest annual decline.

- Shale oil or shale gas is a subset of tight oil and natural gas, which are themselves subsets of unconventional. Production is from fine-grained sedimentary rock composed mostly of consolidated clay or mud—shale. Hydraulic fracturing and horizontal drilling are deployed to make shale production economic.

Also, technology improvements reflect current views. The Brent crude oil price is assumed to reach $108/barrel in real 2018 U.S. dollars by 2050. The average annual U.S. real gross domestic product (GDP) growth rate is assumed at 1.9% for 2018 to 2050 timeframe.

- **EIA High Oil and Natural Gas Resource and Technology Case:**[5] crude oil and natural gas at the national level. This case assumes a higher resource availability at lower costs and higher technology improvements than in the Reference Case. This alternative case allows for higher production at lower prices.

- **EIA Low Oil and Natural Gas Resource and Technology Case:**[6] crude oil and natural gas at the national level. This case assumes lower resources at higher costs and less technology improvements compared to the base case, hence allows lower production at higher prices.

- **IHS Markit Rivalry Scenario:**[7] crude oil, natural gas, and NGLs at the national and subnational levels. The IHS Markit production outlooks are part of a detailed global energy demand, supply, and market outlook. Global market context is a critical influence on U.S. trends. Rivalry posits an intense competition for energy market share—an energy "rivalry." Suppliers of oil, natural gas, coal, nuclear power, and renewable energy compete to preserve traditional markets or dethrone incumbents. Oil prices are generally moderate, but volatile. Oil demand grows until it hits a plateau in the latter half of the 2030s. Higher vehicle fuel economy and other changes in transportation shape the Rivalry demand outlook. Associated gas and Appalachia are the

5 Ibid, 6.

6 Ibid.

7 IHS Markit, Products, Global Scenarios, https://ihsmarkit.com/products/global-scenario.html (accessed November 12, 2019).

engines of natural gas supply growth, until an eventual plateau of associated natural gas leads to new nonassociated gas supply developments. Crude oil, natural gas, and NGLs production outlooks include assumptions about capital availability, costs, and spending discipline. The IHS Markit production outlooks are developed on a well-by-well basis rooted in geological, technological, and market assumptions.

- **IHS Markit Autonomy Scenario:**[8] crude oil and natural gas at the national level. The Autonomy outlooks are part of a global energy demand, supply, and market outlook that illustrates an accelerated move to a less carbon intensive global economy driven by changes in technology, government policy, and consumer behavior. The combination of lower costs for renewable energy, batteries, and autonomous technology with increasingly stringent regulation of carbon emissions are the main drivers of change. Global oil demand and supply peak in the late 2020s, although oil remains a major source of global energy supply. A revolution in mobility linked to electric vehicles, driverless technology, and mobility as a service reshape demand patterns—and thus oil and natural gas supply as well. Oil prices are generally low to moderate, reflecting falling world oil demand after the 2020s.

- **BP's Evolving Transitions Scenario:**[9] crude oil, natural gas, and NGLs at the national level. This scenario assumes policies and technologies will change at a similar rate as they did in the past. It includes a gradual rise in carbon prices and regulation to support low-carbon energy. It projects demand for oil and other liquid fuels increasing by 10 MMB/D (to 108 MMB/D). Most of that growth happens during the first 10 years with demand broadly plateauing in the 2030s. Global oil production becomes geographically more concentrated as low-cost producers gain share. The Middle East, United States, and Russia account for two-thirds of oil production in 2040, up from 60% in 2017.

- **Rystad Energy's Base Case:**[10] crude oil, natural gas, and NGLs at national and subnational levels. Rystad Energy develops its medium- and long-term tight oil view by considering the potential production from more than 2,000 different acreage positions. The assumption underlying the Rystad Energy base case is that the tight oil operators in the U.S. Lower 48 states will operate under cash flow neutrality (investments equal cash from operations). The base case assumption is a West Texas Intermediate (WTI) price of $55 per barrel. The forecast does not assume any efficiency gains and productivity gains but uses the most recent observed drilling efficiency and well performances. For natural gas, the Rystad Energy base case assumes continued strong growth from Appalachia, especially in the short to medium term, as the basin will have the required takeaway capacity after years of bottlenecks preventing growth. Appalachia shale gas supply peaks in the 2030s before slightly declining toward 2040. Associated gas from the Permian Basin is the other main growth driver for U.S. natural gas supply.

- **Wood Mackenzie's Base Case:**[11] crude oil at the national and subnational level. This case assumes minor technological improvement in tight oil recoveries and assumes the cost of supply rises in the United States in the early years of the forecast. Tight oil provides most of the global supply growth through 2025, and well inventories are adequate to sustain production until the 2030s. The base case view is modeled on a Brent price projection that reaches $100 per barrel in real terms in the mid- to late-2030s.

- **Organization of Petroleum Exporting Countries (OPEC):**[12] crude oil and NGLs at the national level. This U.S. production outlook is from the 2018 edition of OPEC's World Oil Outlook (WOO). The U.S. outlook is part of the WOO's Reference Case for world oil demand and supply to 2040.

8 Ibid.

9 *BP Energy Outlook 2019*, https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2019.pdf.

10 Rystad Energy, Rystadenergy.com.

11 Wood Mackenzie, Long-Term Outlook Reports, https://www.woodmac.com/store/outlook-reports/.

12 Organization of Petroleum Exporting Countries, *World Oil Outlook*, 2018, https://www.opec.org/opec_web/en/publications/340.htm.

- **International Energy Agency's New Policies Scenario:**[13] natural gas at the national level. This scenario assumes that existing policies are maintained, and all announced policies are implemented. IEA outlook considers a total North America unconventional, technically recoverable natural gas resource of 2,789 trillion cubic feet. The outlook assumes the Henry Hub natural gas price will be $3.50/million British thermal units (MMBTU) in 2025 when unconventional production will contribute 90% of the total U.S. natural gas production. Over the long term, production from U.S. shale resources will be able to meet the demand at a natural gas price increasing up to $5.60/MMBTU.

2. U.S. Crude Oil Production Outlooks to 2040

There is a wide range of projections for how much crude oil will be produced in the United States—11 crude oil projections to 2040 gathered for this study range from a high of nearly 20 MMB/D to a low of 7 MMB/D (Figure 1-5). Most projections provided for this study show an increase in production through the early- to mid-2020s, except the IHS Markit Autonomy and Rystad Energy scenarios.

A variety of terms are used for future estimates. EIA uses the term "cases." IEA uses the term "scenarios" and other estimators employ the terms "forecast," "prediction," or "projection." None of these imply median, mean, mid-case, P50, or any other probability. They all make assumptions about future uncertainties. These assumptions may be calibrated to existing policies or potential policies. They may be outcome agnostic, or they may attempt to solve for a particular outcome like limiting global warming to 2°C. They are useful on the whole to provide a wide range of possibilities. General descriptions of forecasts used in the supply or demand sections are included in each section.

The outlooks that bracket the high and low ends highlight the importance of assumptions about price, technology, policy, and resources. The EIA's High Oil and Natural Gas Resource and Technology Case projects the highest level of production by 2040. Key assumptions in this outlook, relative to the EIA's Reference Case, are that ultimate recovery per well is assumed to be 50% higher, and technological improvements lead to reduction in costs and gains in productivity that are also 50% higher. The lowest outlook, IHS Markit's Autonomy Scenario, assumes that changes in technology, consumer behavior, and government policy accelerate the move toward a lower-carbon economy, including electrification of the vehicle fleet. This leads to lower oil demand and low prices, which in turn limits upstream investment in crude oil production.

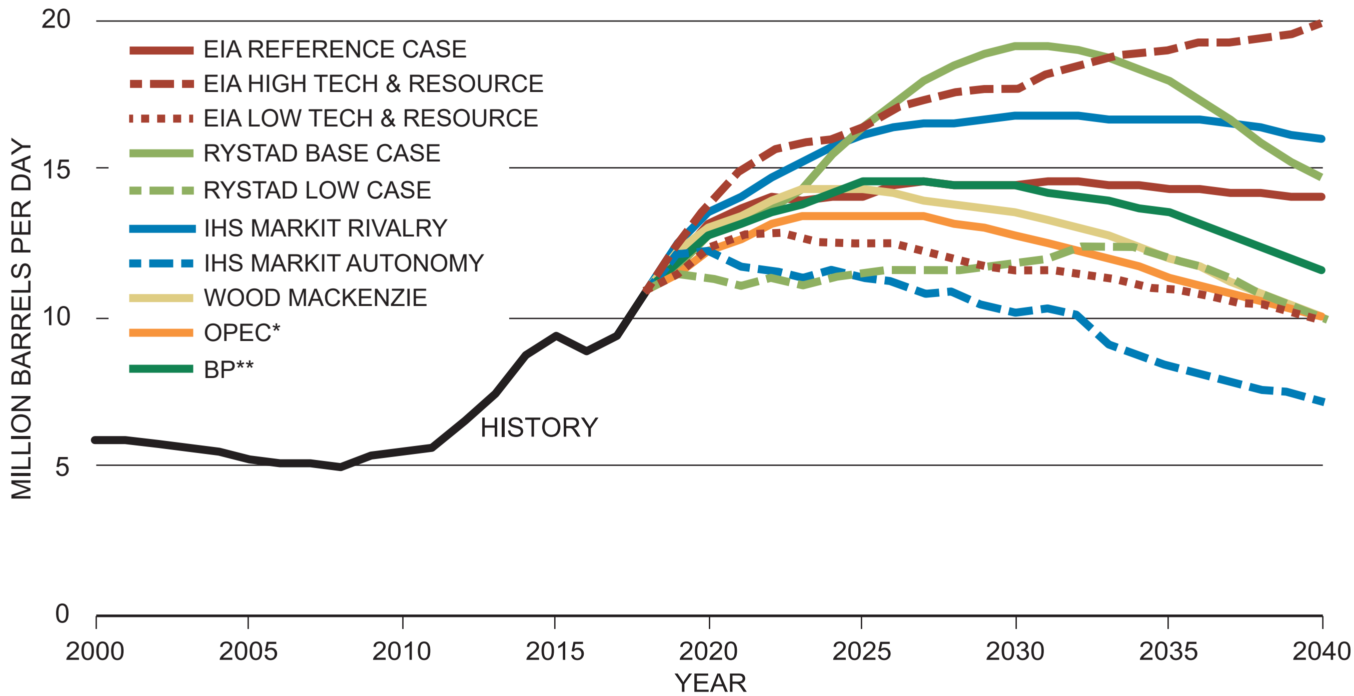
Finding: Long-term projections of U.S. crude oil production show a wide range of outcomes. The variations reflect diverse assumptions about price, technology, policy, and resources.

a. Importance of Export Infrastructure and Access to Export Markets

For most of the outlooks there is at least an implicit assumption of unfettered global trade in oil and natural gas. This is a key assumption, particularly for the outlooks in the higher end of the range. U.S. oil demand outlooks provided to this study generally show demand flat to declining to 2040 with limited gains, if any, in refining capacity. This means that most, or even all, of the growth in U.S. crude oil production is assumed to be exported. Implied U.S. crude oil export growth is significant in most of the U.S. production outlooks gathered for this study. Assuming little change in the volume of domestic production processed in U.S. refineries, U.S. crude oil exports could increase from early 2018 levels by 2 MMB/D to 10 MMB/D in the next two decades.

For the past several decades, unfettered trade was a safe assumption because that is how the world oil market generally functioned. But the future of global trade—including for commodities—has become more uncertain in recent years. United States-China trade tensions are an example of this uncertainty. If trade in oil and natural gas is hobbled by trade barriers or geopolitical rivalries, it raises the risk that future U.S. oil and natural gas production volumes could fall short

13 International Energy Agency, *World Energy Outlook 2018,* Scenarios in WEO 2018, https://www.iea.org/weo2018/scenarios/, (accessed November 13, 2019).



Sources: EIA *Annual Energy Outlook* 2019, Rystad Energy, IHS Markit, BP, OPEC, and Wood Mackenzie.
* OPEC outlook released in 2018. Other outlooks from 2019. ** *BP Energy Outlook*, 2019, Evolving Transitions scenario.

Figure 1-5. *U.S. Crude Oil Production Forecasts to 2040*

of growth projections if access to export markets is constrained.

> ***Finding:*** Access to export markets is a critical assumption in outlooks showing growth in U.S. crude oil, natural gas, and NGLs production.

b. U.S. Crude Oil Export Infrastructure

Most U.S. crude oil exports are from marine terminals stretching from Mobile, Alabama, to Corpus Christi, Texas, on the Gulf Coast. Nearly all future growth is likely to be from the Gulf Coast as well, based on the supply projections gathered for this study. Improved and expanded infrastructure will be needed to accommodate such growth.

c. Size of the U.S. Crude Oil and Natural Gas Resource Base

Technically Recoverable Resources (TRR) are those that can be produced using current recovery technology, industry practice, and geologic knowledge. This category of resources does not consider economic profitability, so it is independent of price and cost assumptions. Because both price and costs can vary widely over relative short periods of time, TRR is a particularly useful measure of the "size of the prize." It also allows for easier comparisons of estimates among parties with different price and cost assumption views.

As part of its Annual Energy Outlook, the EIA publishes its TRR estimate for the United States every year. Table 1-1 summarizes the most recent data available.

TRR estimates all the oil and natural gas that can be produced based on current technology, industry practice, and geologic knowledge. Economically recoverable resource is a subset of TRR. Estimates are not static. For example, TRR oil in the United States increased by about 10% from the 2014 estimate of 274 billion barrels, driven mostly by the U.S. Lower 48 onshore region. At the rate of U.S.

	Crude Oil (billion barrels)	Dry Gas (trillion cubic feet)	Total Resource (billion barrels of oil equivalent)
U.S. Lower 48 Onshore	204	1,976	560
U.S. Lower 48 Offshore	53	239	96
Alaska	46	244	90
Total United States	**303**	**2,459**	**746**

Source: EIA, Assumptions to *Annual Energy Outlook 2019*, Oil and Gas Supply Module.

Table 1-1. *Total Technically Recoverable Oil and Natural Gas Resources in the United States, January 1, 2017*

crude oil production in 2018 (~10.9 MMB/D), and without factoring in further technology improvements or economics, the United States could maintain the 2018 crude oil production level for about 77 years.

d. Crude Oil Production Outlooks for Select Subnational Areas

Understanding the geography of U.S. crude oil production is a key part of assessing current and potential infrastructure needs. This section provides outlooks for crude oil production to 2040 for six areas that accounted for most of the crude oil produced in the United States in 2018. These areas (U.S. Lower 48 onshore areas are shown in Figure 1-4) along with 2018 crude oil output volumes are as follows:

- Permian Basin in West Texas and Southeast New Mexico, 2018 production: 3.4 MMB/D
- Gulf of Mexico (offshore), 2018 production: 1.7 MMB/D
- Eagle Ford formation in South Texas, 2018 production: 1.4 MMB/D
- Bakken formation in North Dakota, 2018 production: 1.3 MMB/D
- Alaska, 2018 production: 0.5 MMB/D
- DJ (Denver-Julesburg) Basin in Colorado and Wyoming, 2018 production: 0.5 MMB/D.

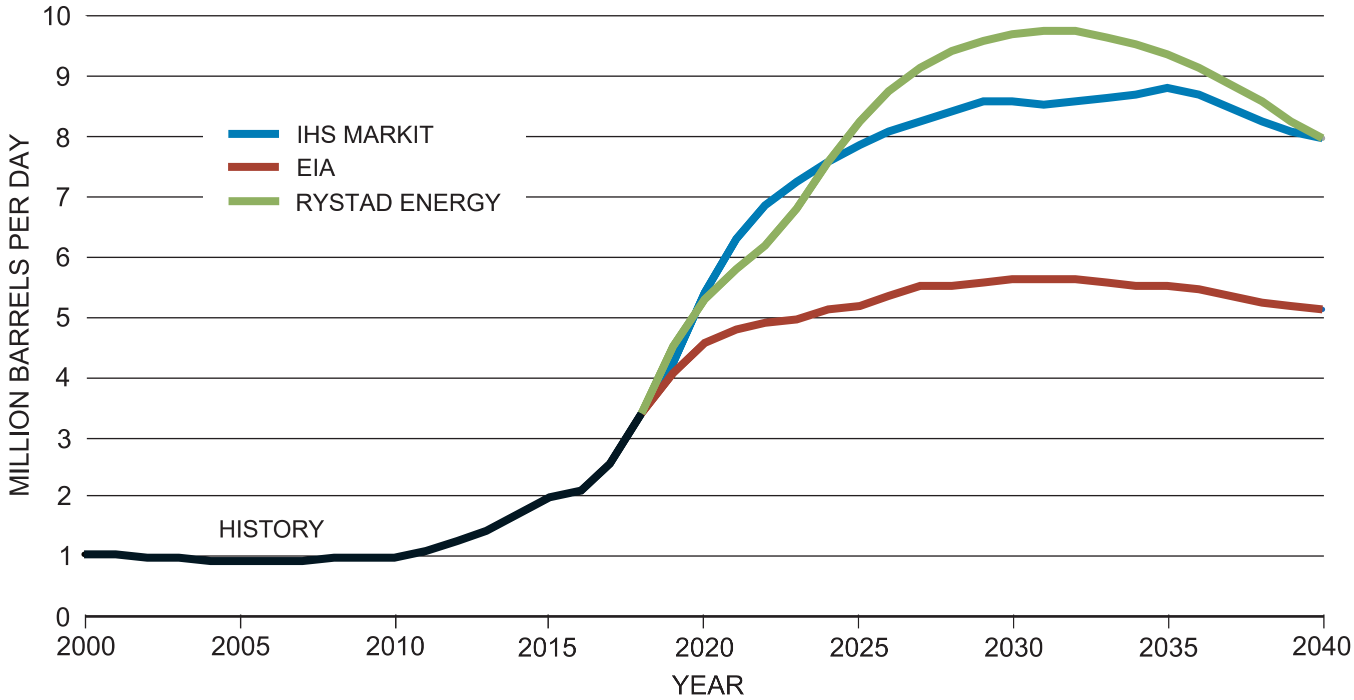
Collectively, these six areas produced 8.8 MMB/D in 2018—80% of total U.S. crude oil production. There could be other areas that play important roles in future crude oil production that are currently underappreciated. In any case, the six areas were chosen because they already are important sources of supply and will likely remain so for many years.

i. Permian Basin Crude Oil Production Outlooks

Outlooks for Permian Basin crude oil production project more growth through at least the mid-2020s, although the possibility of low oil price levels and less capital availability pose risks to these outlooks, as they do for all U.S. production. The IHS Markit and Rystad Energy outlooks project growth until around 2029 to 2030. Rystad Energy projects the highest level of output at 9.7 MMB/D—comparable to what Saudi Arabia has produced at times in 2019. IHS Markit projects a peak at 8 MMB/D in 2035, although the rate of growth decelerates by the late 2020s (see Figure 1-6).

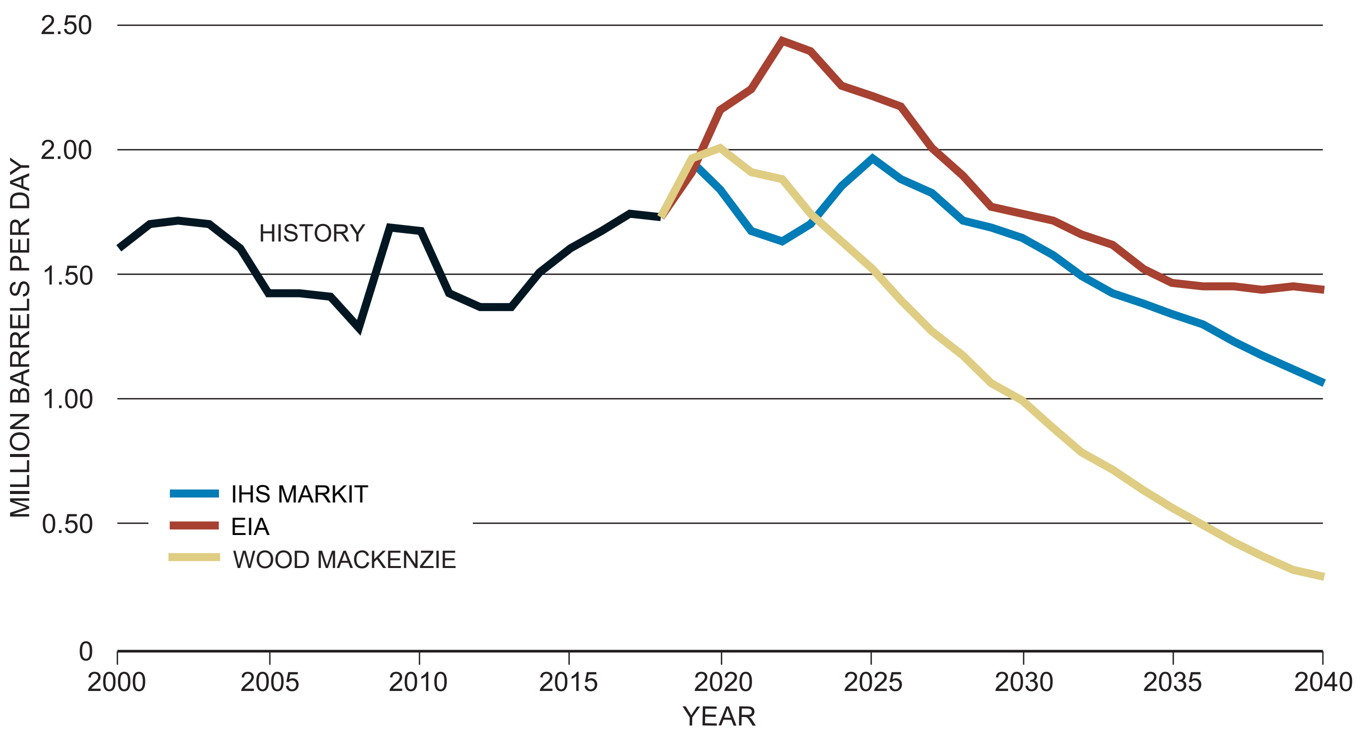
> ***Finding:*** The Permian Basin in West Texas and Southeast New Mexico is the most important source of recent and projected crude oil production growth.

A key assumption in all the outlooks appears to be that rising Permian Basin output, which is light sweet crude oil, will find markets overseas. If overseas markets are unable to absorb Permian Basin supply growth due to weaker than expected



Sources: IHS Markit, EIA *Annual Energy Outlook 2019*, and Rystad Energy.

Figure 1-6. *Permian Basin Crude Oil Production Outlooks to 2040*



Sources: IHS Markit, EIA *Annual Energy Outlook 2019*, and Wood Mackenzie Q1 2019.

Figure 1-7. *U.S. Gulf of Mexico Crude Oil Production Outlooks to 2040* demand or trade issues, then growth in the Permian Basin will likely fall short of the Rystad Energy and IHS Markit outlooks.

ii. Permian Basin: Implications of Production Outlooks on Takeaway Capacity

Significant takeaway capacity has been and is being added to the Permian Basin, but more is likely to be needed based on the Rystad Energy and IHS Markit outlooks, and, to a lesser extent, the EIA outlook. Since crude oil production growth from the Permian Basin will mostly, if not entirely, be exported, more takeaway capacity to coastal export terminals is likely to be needed based on the outlooks. Political or other trade related constraints that negatively impact the export of U.S. crude oil could lead to a different production profile than illustrated by the EIA, IHS Markit, and Rystad Energy projections.

iii. Gulf of Mexico Crude Oil Production Outlooks

There is a divergence of views about the future trajectory of Gulf of Mexico crude oil production. The EIA projects significant growth until a peak of 2.4 MMB/D by 2024, propelled by development of deepwater discoveries made before the late 2014 to 2015 oil price collapse. Output falls until the 2030s when a plateau of 1.5 MMB/D is reached as new fields offset declines from older fields. At the low end of projections is the Wood Mackenzie outlook, which shows perennial declines after a peak of 2 MMB/D in 2020. By 2040 crude oil production is just 250,000 B/D (see Figure 1-7).

The IHS Markit outlook is in the middle but tracks closer to the EIA outlook long term. The forecast for 2019 to 2020 is for output to range around 1.9 MMB/D to 2 MMB/D as field startups over the past 4 years reach plateau level or start declining. Field startups in 2018 to 2019 and other smaller tiebacks will only be able to offset declines from existing fields in Gulf of Mexico deep and shallow water. IHS Markit expects production to dip in the early 2020s before rising again around 2023 and then matching the 2020 level of 2 MMB/D again by 2025. The success, or lack thereof, of Lower Tertiary projects could have significant impact on Gulf of Mexico outlook in the medium to long term.

iv. Gulf of Mexico: Implications of Production Outlooks on Takeaway Capacity

The Wood Mackenzie and IHS Markit outlooks imply few, if any, future infrastructure bottlenecks offshore the U.S. Gulf of Mexico, unless there are changes in the geography of production that would require investment to ship production to an existing pipeline, or otherwise get it to market. An uncertainty is if existing transport capacity is shut due to low utilization and what, if any, knock-on impact that could have. Also, competition between different oil producing areas, including the Gulf of Mexico, for onshore infrastructure could materialize. The EIA outlook does standout for the growth it projects, but it is not clear what is driving higher output and what type of infrastructure may be needed to get the oil to market. Production growth in the EIA peaks at around 2022 and then declines to the 2018 level by 2029.

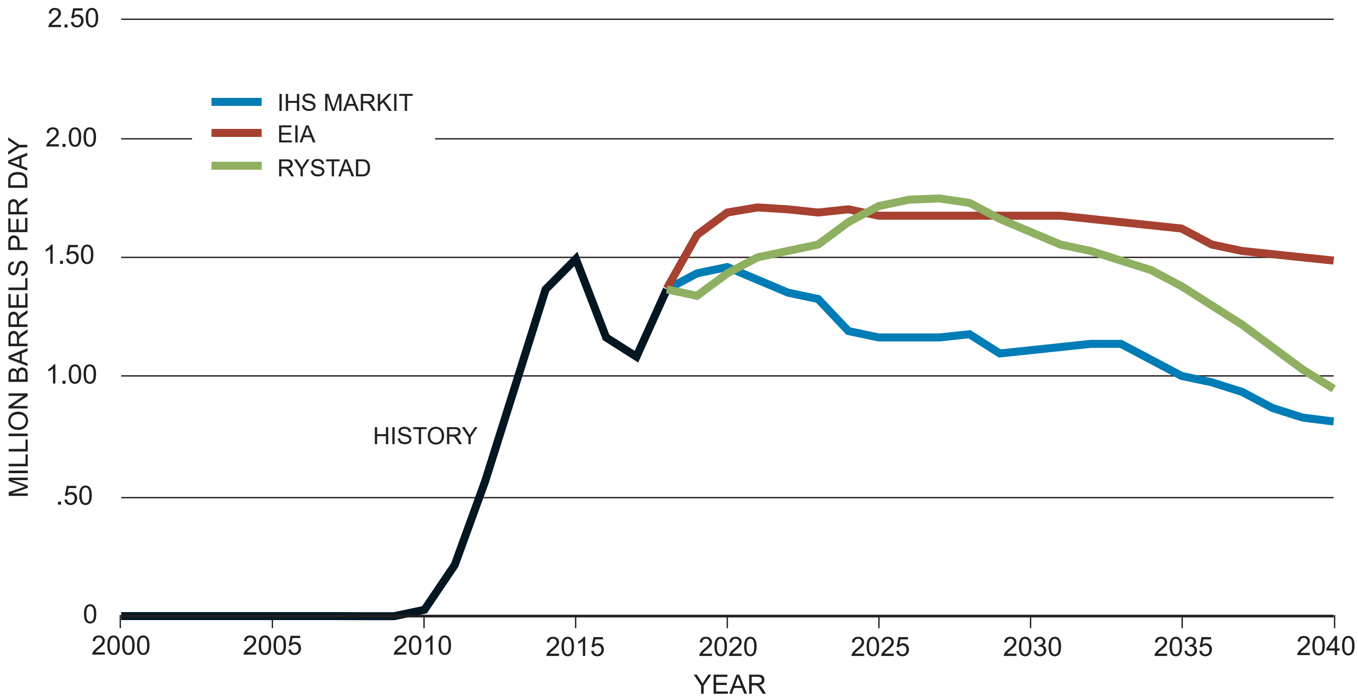
v. Eagle Ford Crude Oil Production Outlooks

According to production outlooks from the EIA, IHS Markit, and Rystad Energy, the great growth era of Eagle Ford crude oil production is over (Figure 1-8). It is expected, however, to remain a significant source of supply to 2040.

The IHS Markit outlook assumes that signs of "sweet spot exhaustion" are emerging. This means, in the context of the IHS Markit outlook, that many of the best drilling locations have already been developed, which negatively impacts growth potential. Of course, critical to these assumptions are oil price and fiscal discipline of operators—should oil price rise from the base case expectation, operators will look to the Eagle Ford to grow volumes.

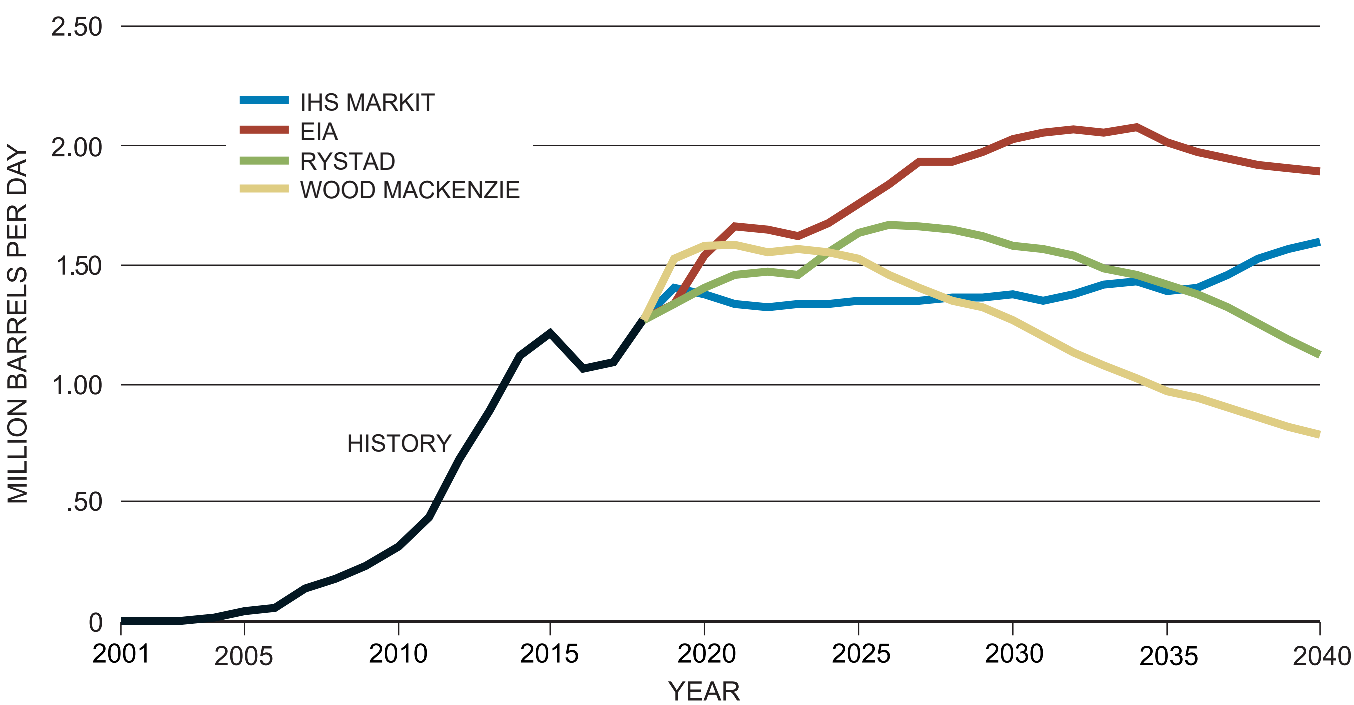
vi. Eagle Ford: Implications of Production Outlooks on Takeaway Capacity

Two of the three production outlooks—the EIA and Rystad Energy—show Eagle Ford crude oil production increasing by roughly 400,000 B/D over the next decade. The EIA outlook shows that growth materializing in short order—by 2021—and then generally flat through the mid-2030s. The IHS Markit outlook shows little to no growth after 2020 to 2021 before entering a long-term decline.



Sources: IHS Markit, EIA *Annual Energy Outlook 2019*, and Rystad Energy.

Figure 1-8. *Eagle Ford Crude Oil Production Outlooks to 2040*



Sources: IHS Markit, EIA *Annual Energy Outlook 2019*, Rystad Energy, and Wood Mackenzie Q1 2019.

Figure 1-9. *Bakken/Williston Basin Crude Oil Production Outlooks to 2040*

vii. Bakken Crude Oil Production Outlooks

With the exception of IHS Markit, outlooks for Bakken production project rising production in the early 2020s, but at a much slower rate than the boom from 2010 to 2015 (Figure 1-9). The EIA outlook stands out for its long-term growth projection, which has Bakken output reaching 2.1 MMB/D around 2030. Rystad Energy is the next highest outlook—peaking at 1.7 MMB/D in 2026.

viii. Bakken: Implications of Production Outlooks on Takeaway Capacity

Most outlooks imply that the era of exceptional production growth is over for the Bakken. The EIA outlook stands out for projecting a near doubling of 2018 production levels by 2030. The EIA outlook implies that significant new takeaway capacity will be needed. The other outlooks imply a transport system with moderate to little growth challenges.

ix. Alaska Crude Oil Production Outlooks

There are differing projections of long-term crude oil production in Alaska (Figure 1-10). EIA projects output will more than double from 2018 levels and reach 1.3 MMB/D by 2040. Wood Mackenzie is at the other end of the spectrum. After an increase to 750,000 B/D by the mid-2020s, Wood Mackenzie's outlook is for a drop below 250,000 B/D by 2040. The IHS Market outlook projects relatively steady production between 400,000 B/D and 750,000 B/D.

x. Alaska: Implications of Production Outlooks on Takeaway Capacity

All Alaskan crude oil flows through the Trans-Alaska Pipeline System (TAPS). The original capacity on the TAPS line was more than 2 MMB/D. Removal of pump stations over time has lowered throughput capacity to a maximum between 750,000 B/D to 1 MMB/D. Flow over this range would require reinstallation of pump stations.

xi. DJ Crude Oil Production Outlooks

According to production outlooks from the EIA, IHS Markit, and Wood Mackenzie, DJ Basin production will continue to grow peaking at 0.45 MMB/D to 0.85 MMB/D (Figure 1-11). Except for the EIA outlook, other DJ Basin outlooks show that production will continue to grow in the next decade. The EIA outlook reaches a peak of 0.45 MMB/D in 2021 and stays flat afterwards. The IHS Markit outlook reaches around 0.7 MMB/D by 2023, while the Wood Mackenzie outlook peaks around 0.7 MMB/D, but at a relatively slower growth rate compared to the IHS Markit outlook.

A new law—Bill 181—was approved in Colorado in April 2019. The new law gives more control over oil and natural gas regulations to local governments under their planning and land-use powers. Its impact on future oil and natural gas production is uncertain.

xii. DJ Basin: Implications of Production Outlooks on Takeaway Capacity

While Wood Mackenzie and IHS Markit outlooks show output growing by an additional 0.25 MMB/D to 0.3 MMB/D in the 2020s, EIA outlook shows flat production after 2021. In general, growth outlooks imply some degree of future infrastructure needs to get crude oil to the market.

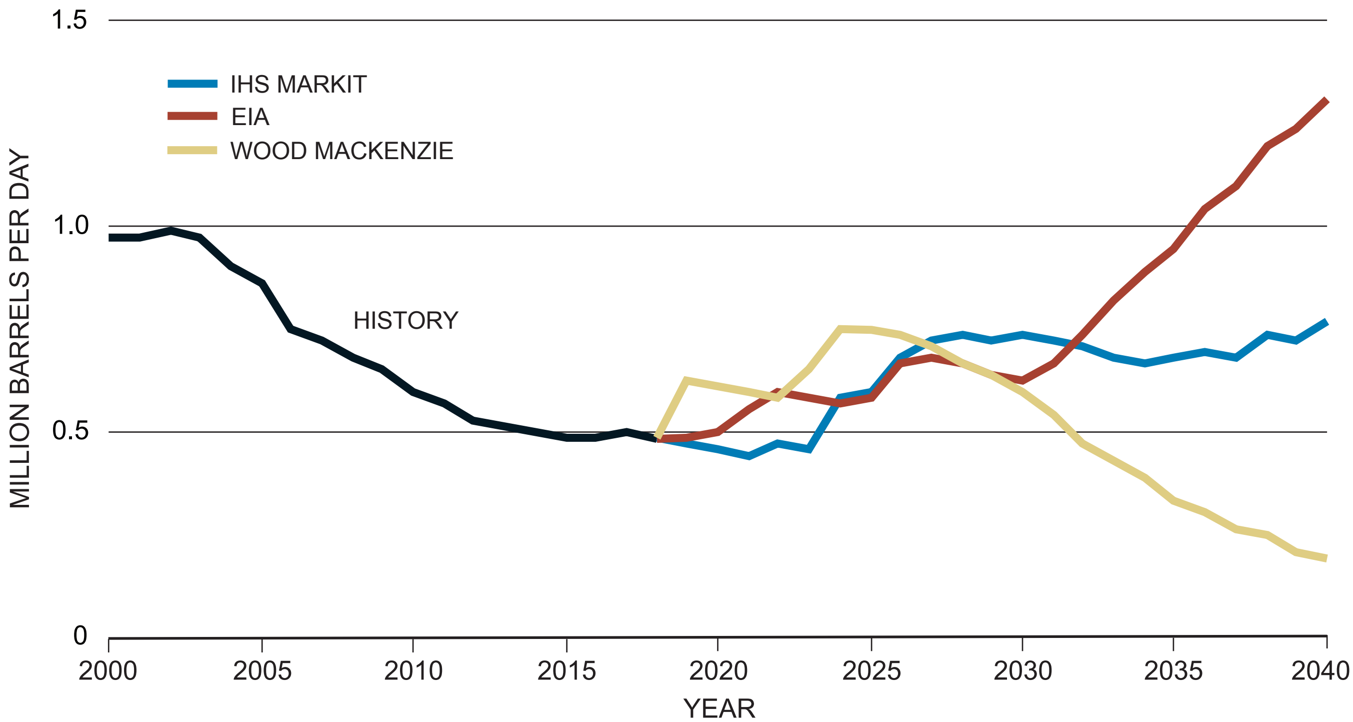
Crude oil supply growth has been driven by five plays (Permian, Eagle Ford, Bakken, DJ, and Scoop/Stack) in five states (New Mexico, Texas, North Dakota, Colorado, and Oklahoma). Therefore, the ability to leverage existing, and build out new, infrastructure has been critical to delivering the supply to demand centers.

3. U.S. Natural Gas Production Outlooks to 2040

U.S. natural gas production[14] in 2018 was 83 BCF/D—up 69% since 2005, just before the dawn of the shale gas era. A large and economic resource base creates the potential for U.S. natural gas output to impact global markets for decades to come.

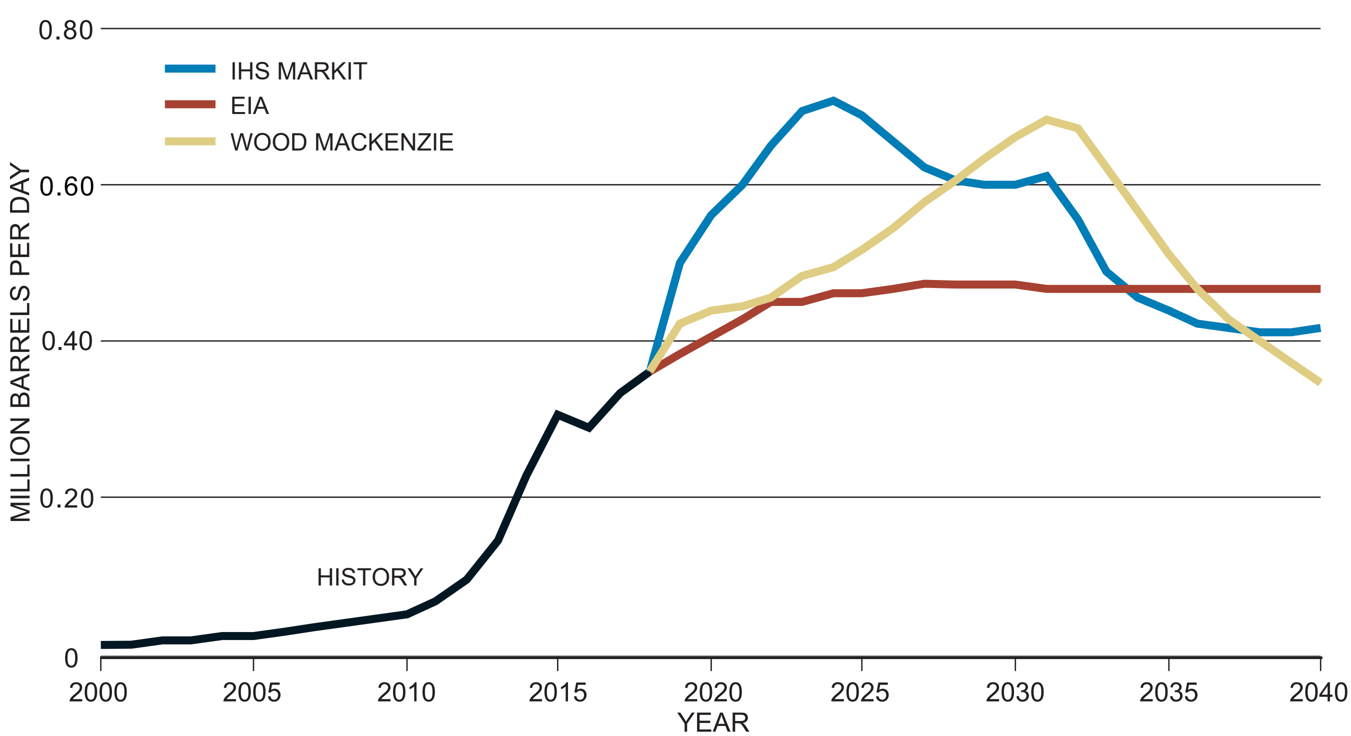
There is a wide range of projections for U.S. natural gas production to 2040 (Figure 1-12). The outlooks to 2040 range from a high of 137 BCF/D to a low of 83 BCF/D. The outlooks that form this

14 Natural gas refers to dry natural gas—methane only with no NGLs included.



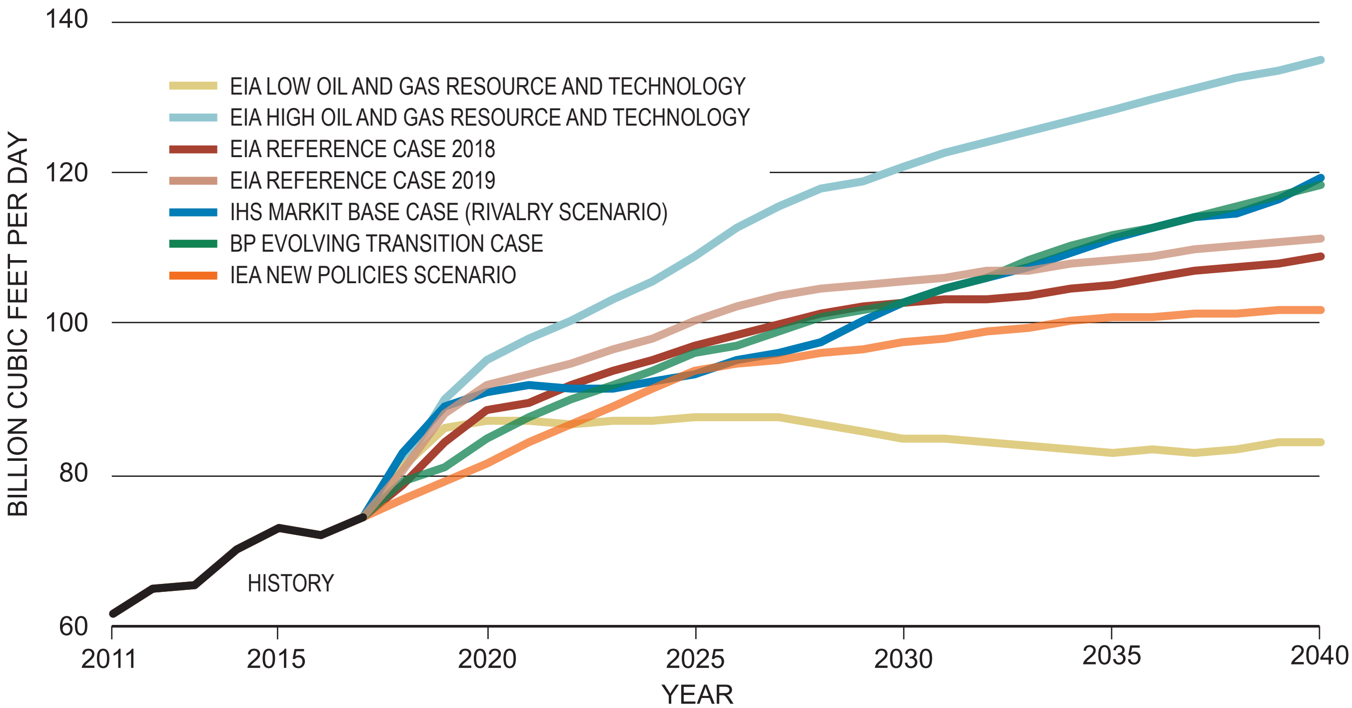
Sources: IHS Markit, EIA *Annual Energy Outlook 2019*, and Wood Mackenzie Q1 2019.

Figure 1-10. *Alaska Crude Oil Production Outlooks to 2040*



Sources: IHS Markit, EIA *Annual Energy Outlook 2019*, and Wood Mackenzie Q1 2019.

Figure 1-11. *DJ Basin Crude Oil Production Outlooks to 2040*



Sources: EIA *Annual Energy Outlook 2018* and *2019*; IHS Markit; *BP Energy Outlook 2019*; and International Energy Agency, *World Energy Outlook 2018*.

Figure 1-12. *U.S. Natural Gas Production Forecasts to 2040*

range are the EIA Reference Case, EIA side cases, IEA New Policies Scenario, BP Evolving Transition Case, IHS Markit Rivalry Scenario, and Rystad Energy Base Case. The highest curve, the EIA high oil and gas resource technology case, assumes higher resource availability at lower costs and higher technology improvements than in the EIA Reference Case. The lowest curve, the EIA low oil and gas resource technology case, assumes lower resources at higher costs and less technology improvements than in the EIA Reference Case. Historical natural gas production by play data is from EIA, Natural Gas, Production data, "Dry shale gas production estimates by play."[15]

a. Natural Gas Production Outlooks to 2040 for Select Subnational Areas

Outlooks for five subnational areas are provided in this section. These regions are shown because of previous, current, or future importance to U.S. natural gas supply. The regions are Appalachian Basin, Permian Basin, Haynesville, Barnett, and the Gulf of Mexico.

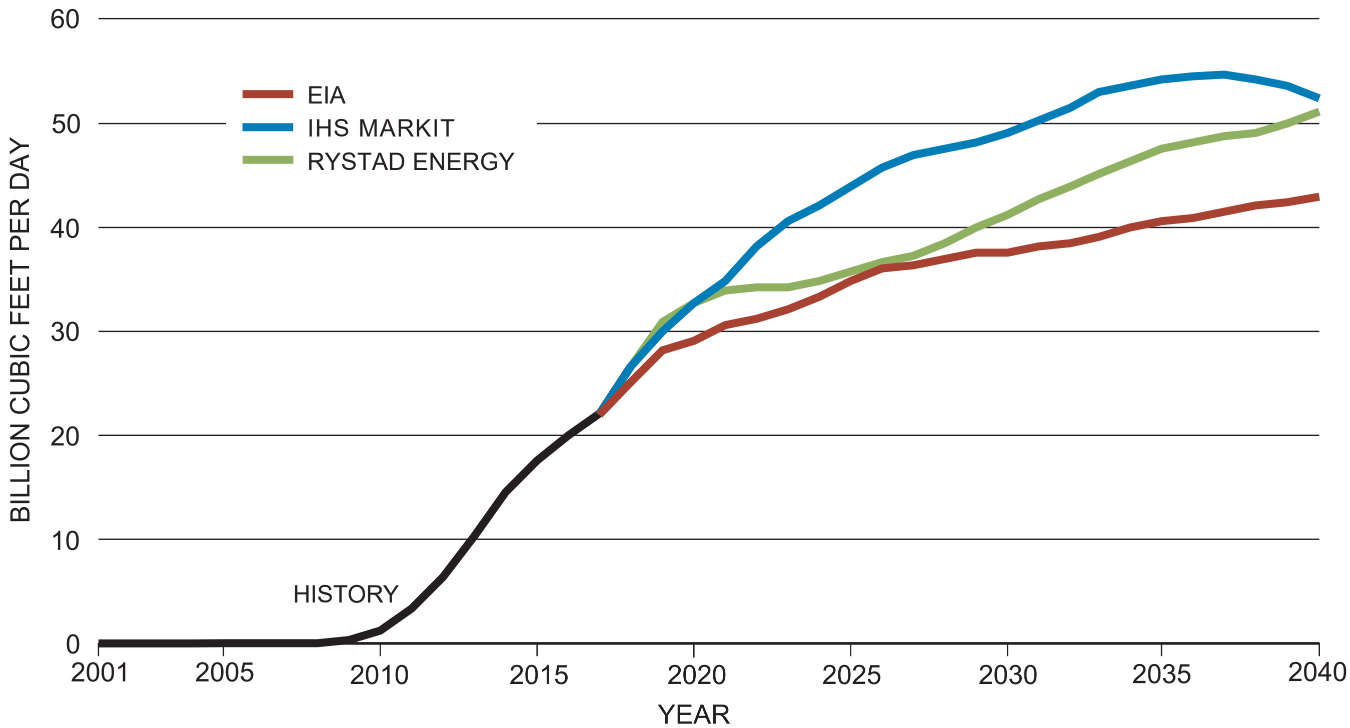
Finding: Long-term projections of U.S. natural gas show a range of outcomes. The variations reflect diverse assumptions about price, technology, policy, and resources.

i. Appalachian Basin Natural Gas Production Outlooks

Appalachia natural gas production is projected to increase to a range of 42.9 BCF/D to 52.4 BCF/D by 2040, up from 25.3 BCF/D in 2018. The Marcellus and Utica formations are the most prolific producing formations in the Appalachian Basin. Appalachia production could account for more than 40% of total U.S. production by 2040.

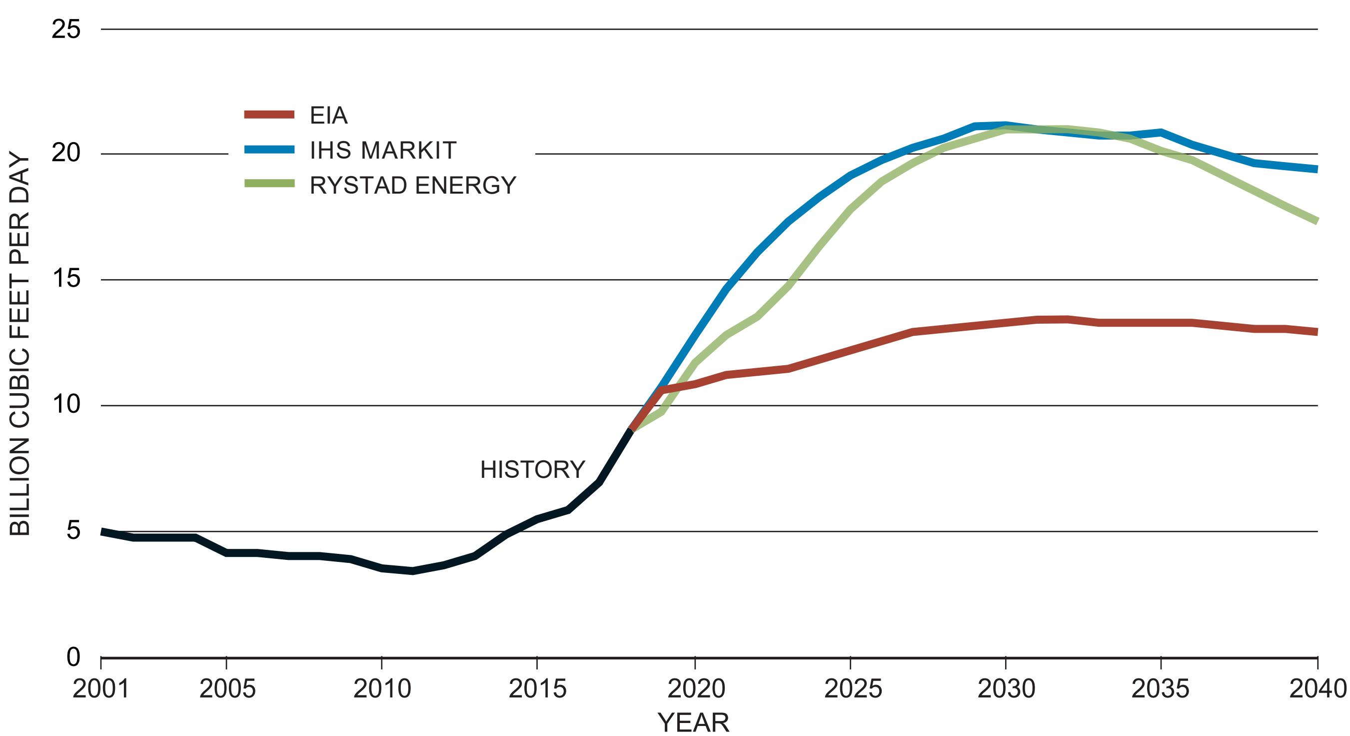
All three outlooks—from the EIA, IHS Markit, and Rystad Energy—project further production growth in the next several years (see Figure 1-13).

15 U.S. Energy Information Administration, Natural Gas, Data, Production, Dry shale gas production estimates by play, October 17, 2019, release, shale_gas_ 201909.xlsx.



Sources: IHS Markit, Rystad Energy, and EIA *Annual Energy Outlook 2019*.

Figure 1-13. *Appalachia Natural Gas Production Outlooks Show Production Rising*



Sources: IHS Markit, EIA *Annual Energy Outlook 2019*, and Rystad Energy.

Figure 1-14. *Diverging Views about Future Natural Gas Production Growth from Permian Basin*

There are different views about the pace of growth during the 2020s. In 2030, the difference between the high and low forecasts is greater than in 2040. The reasons for these differences are likely related to some mix of assumptions about natural gas prices, well productivity and economics, and infrastructure.

Finding: The Appalachian Basin is the most important source of U.S. natural gas supply growth to 2040 according to the outlooks provided to this study.

ii. Appalachian Basin: Implications of Production Outlooks on Takeaway Capacity

Appalachian production grew by almost 4 BCF/D during 2018 as natural gas producers filled new pipelines as they became available. The conversions of drilled wells to producing wells was aligned with pipeline additions. This will change as associated gas production, particularly in the Permian Basin, increases as a share of total U.S. natural gas production.

iii. Permian Basin Natural Gas Production Outlooks

IHS Markit and Rystad Energy expect Permian Basin natural gas supply to double from the 2018 level—increasing around 12 to 13 BCF/D by 2030. This would put total Permian Basin natural gas production near 21 BCF/D. The EIA is more moderate in its expectations and forecasts a plateau of less than 14 BCF/D being reached in the late 2020s (Figure 1-14).

iv. Permian Basin: Implications of Production Outlooks on Takeaway Capacity

Lack of natural gas pipeline takeaway capacity in 2018 to 2019 led to regional prices falling as low as negative $6 per MMBTU, which also led to an increase in natural gas flaring. Flaring is burning off natural gas at the wellhead and is regulated on a state-by-state basis. Additional pipeline capacity is required to reduce flaring and to accommodate associated gas production as oil production increases. New pipeline capacity out of the region will need to more than double from 2018 to 2030 according to the IHS Markit and Rystad Energy outlooks.

v. Haynesville Natural Gas Production Outlooks

IHS Markit, Rystad Energy, and the EIA have different expectations for Haynesville production (Figure 1-15). The EIA and IHS Markit project production to reach more than 10 BCF/D by 2040 while Rystad Energy expects production to reach a peak of around 8.6 BCF/D in 2022 and then decline afterwards. Haynesville natural gas production will remain competitive and can respond to price signals should associated gas and Appalachian natural gas production falter in supplying rising LNG export demand on the Gulf Coast.

According to the IHS Markit outlook, strong growth in the associated and Appalachia natural gas volumes will keep Haynesville growth subdued in IHS Markit case, and slow or flat growth in other cases. Rystad Energy predicts that Haynesville will manage to keep up activity toward 2030, despite lower natural gas prices.

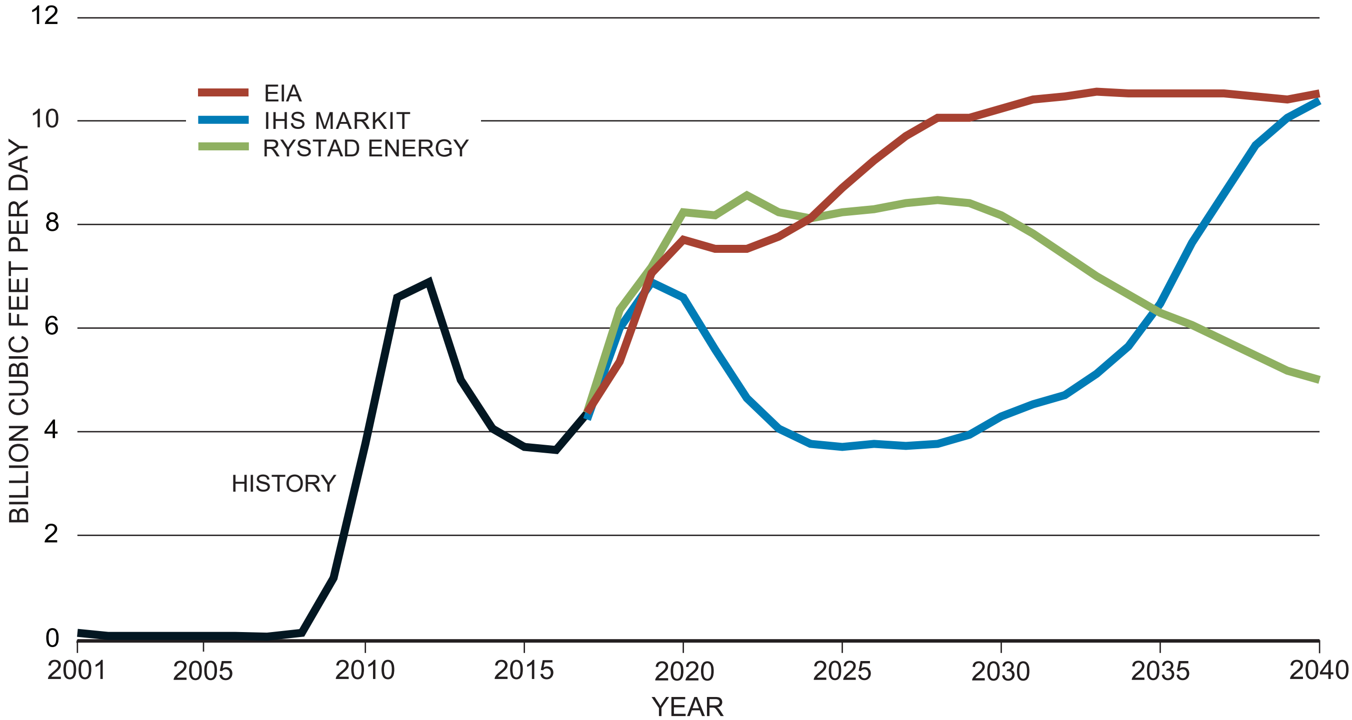
In the long term, noncore areas of the play could become economical to drill if natural gas prices rise. The best locations in the play are limited, and the play resources may not be able to compete with drilling opportunities in Appalachia.

vi. Haynesville: Implications of Production Outlooks on Takeaway Capacity

Based on the IHS Markit and EIA outlooks, Haynesville natural gas production nearly doubles to 2040 relative to 2018, although the IHS Markit outlook shows a decline in the early to mid-2020s before growth re-emerges. This is based on the view that rising associated gas production—such as from the Permian Basin—will lower supply from the Barnett until associated gas output growth eventually stalls. Currently, takeaway capacity is not a constraint in the region, but the outlook implies that some expansion will be needed to handle the long-term flows.

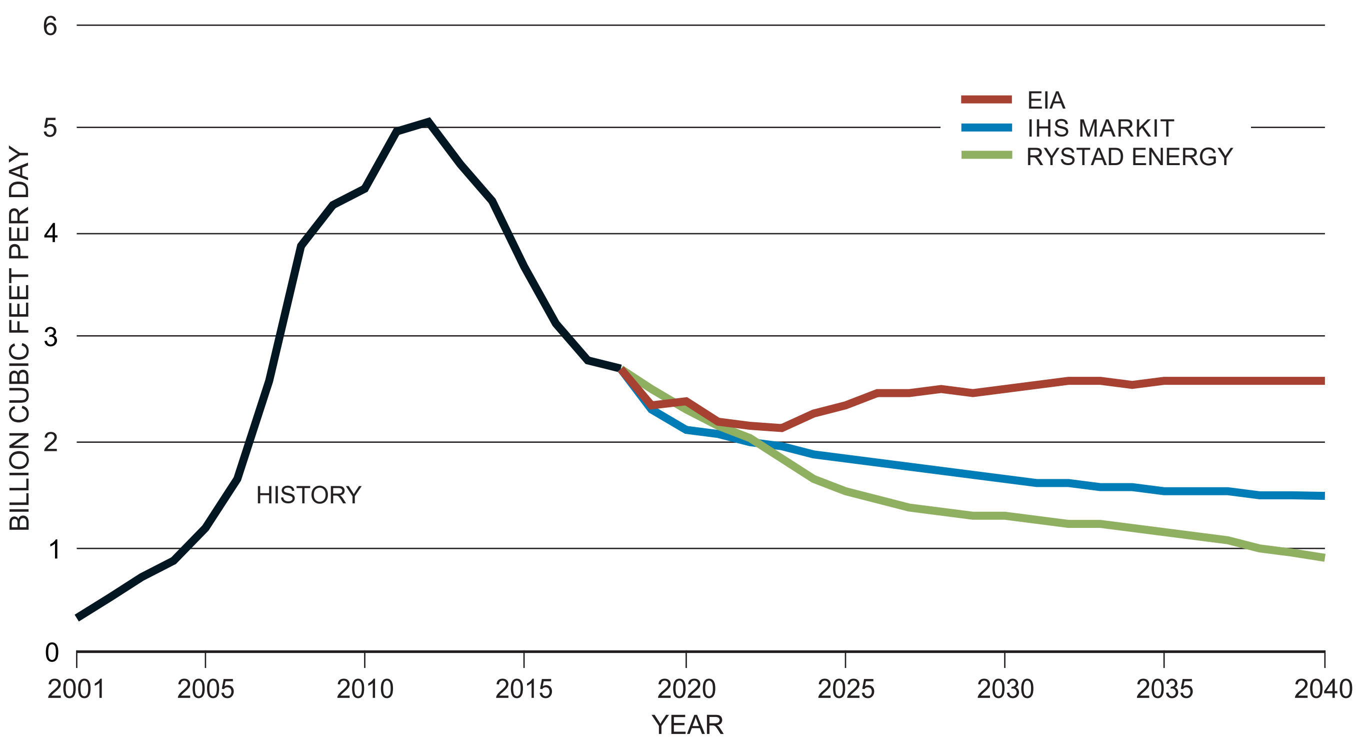
vii. Barnett Natural Gas Production Outlooks

Prior to 2010, high natural gas prices supported enough drilling activity to increase natural gas production to a peak of 5.1 BCF/D in 2012. Associated gas production in the Permian Basin and lower prices since then have limited activity in the



Sources: EIA *Annual Energy Outlook 2019*, IHS Markit, and Rystad Energy.

Figure 1-15. *Outlooks for Haynesville Natural Gas Production Vary Widely*



Sources: EIA *Annual Energy Outlook 2019*, IHS Markit, and Rystad Energy.

Figure 1-16. *Little Change Expected for Barnett Natural Gas Production*

Barnett—natural gas output was about 2.7 BCF/D in 2018. Production is forecast within a range of 0.9 to 2.7 BCF/D by 2040 (Figure 1-16). Appalachia, Haynesville, and associated gas volumes are sufficient to meet natural gas demand until 2040, and the forecasts do not anticipate any recovery in the Barnett play.

viii. Barnett: Implications of Production Outlooks on Takeaway Capacity

None of the forecasts expect Barnett production to rise to its former peak, so Barnett production trends are not expected to create bottlenecks, although associated gas from the Permian Basin will compete for pipeline capacity with Barnett output.

ix. Gulf of Mexico Natural Gas Production Outlooks

Little change is expected in Gulf of Mexico natural gas production according to the EIA, IHS Markit, and Rystad Energy outlooks (Figure 1-17). Plentiful onshore supplies create little incentive to develop offshore natural gas fields. Associated gas production is expected to support a long-term production plateau of around 1.6 BCF/D to 3.1 BCF/D to 2040. The EIA outlook does differ in that it projects production reaching 4 BCF/D in the early 2020s. The EIA outlook is presumably fueled by its higher crude oil production outlook and thus higher associated gas production.

x. Gulf of Mexico: Implications of Production Outlooks on Gulf of Mexico

Historically, the Gulf of Mexico offshore gas fed the East Coast market. The forecasts in Figure 1-17 show future production well below historical highs. Therefore, no new infrastructure is anticipated in this area.

4. U.S. NGL Production Outlooks to 2040

The trajectory of oil and natural gas production will directly shape that of NGLs production. The EIA AEO 2019 highlights NGL production as a byproduct of oil and natural gas development as "most natural gas plant liquids (NGPL) production growth in the Reference Case occurs before 2025 as producers focus on natural gas liquids-rich plays, where NGPL-to-gas ratios [shown in Figure 1-18] are highest and increased demand spurs higher ethane recovery."[16] NGPLs is interchangeable with NGLs in this study. Historical production data for natural gas plant liquids (GPL) is provided by EIA.[17]

There are two additional concepts in EIA's statement relevant to NGLs supply:

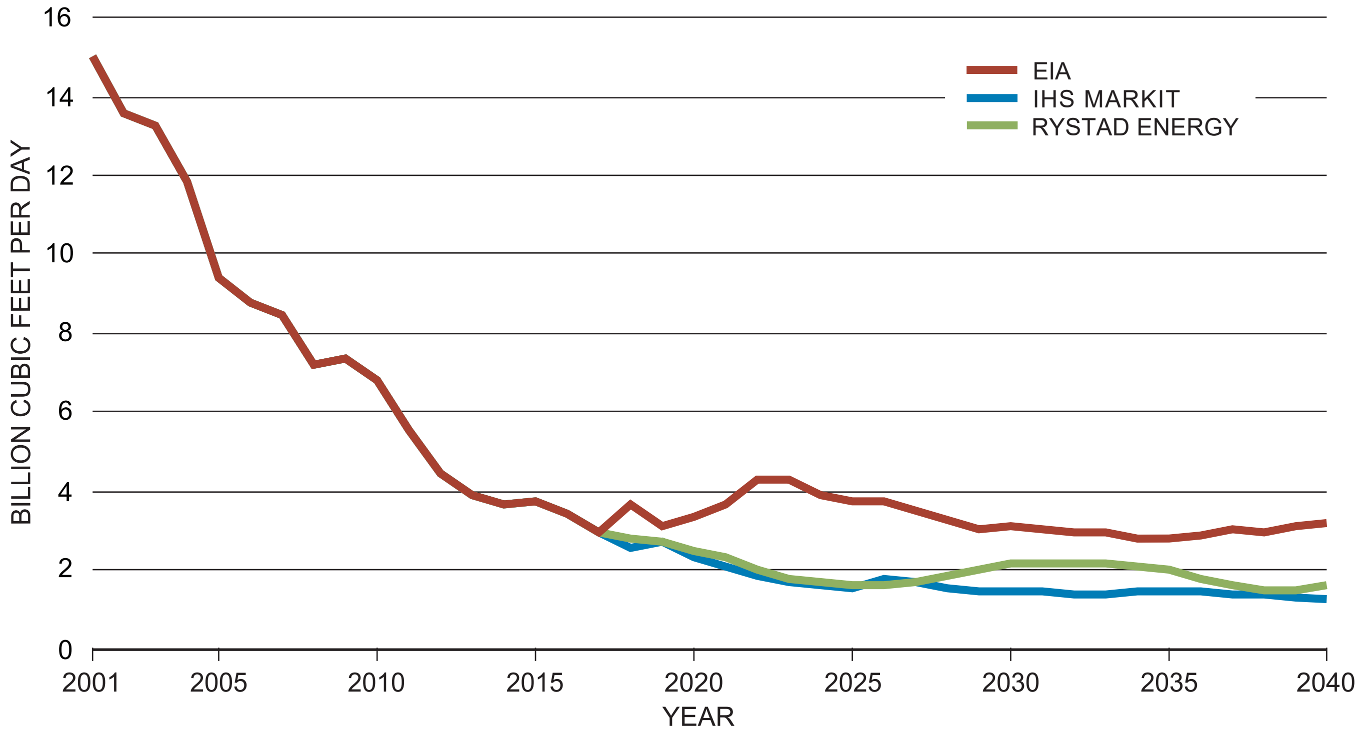
- "Liquids-rich plays" refers to those geological areas or plays like the Marcellus and Utica (both in the Appalachian Basin) in which hydrocarbon production has more NGLs, or liquids, relative to dry gas, or methane, compared to other plays. What constitutes a play being liquids rich versus dry gas is debatable, but the more liquids rich a play, the more NGLs it will produce per unit of natural gas production.

- "Ethane recovery" refers to NGL fractionators removing ethane from the hydrocarbon stream and selling it to ethane end users, typically petrochemical facilities. Ethane recovery contrasts with ethane rejection in which ethane is left in the natural gas/methane stream and is sold as natural gas. The recovery or reject decision is a function of the relative market value of ethane versus natural gas/methane (economic recovery or rejection) and, in some instances, a function of the lack of infrastructure to recover ethane (forced rejection).

With limited exception, the consensus is for NGL supply growth to continue, with forecasts other than the EIA Low Oil and Natural Gas Resource and Technology Case showing increases (Figure 1-19). The average growth across forecasts is 1.6 MMB/D, representing a 40% increase in total NGL production compared to 2018 (range of 0.1 MMB/D in the EIA Low Oil and Natural Gas Resource and Technology Case to 3.3 MMB/D in the EIA High Oil and Natural Gas Resource and Technology Case). BTU Analytics long-term outlook for natural gas

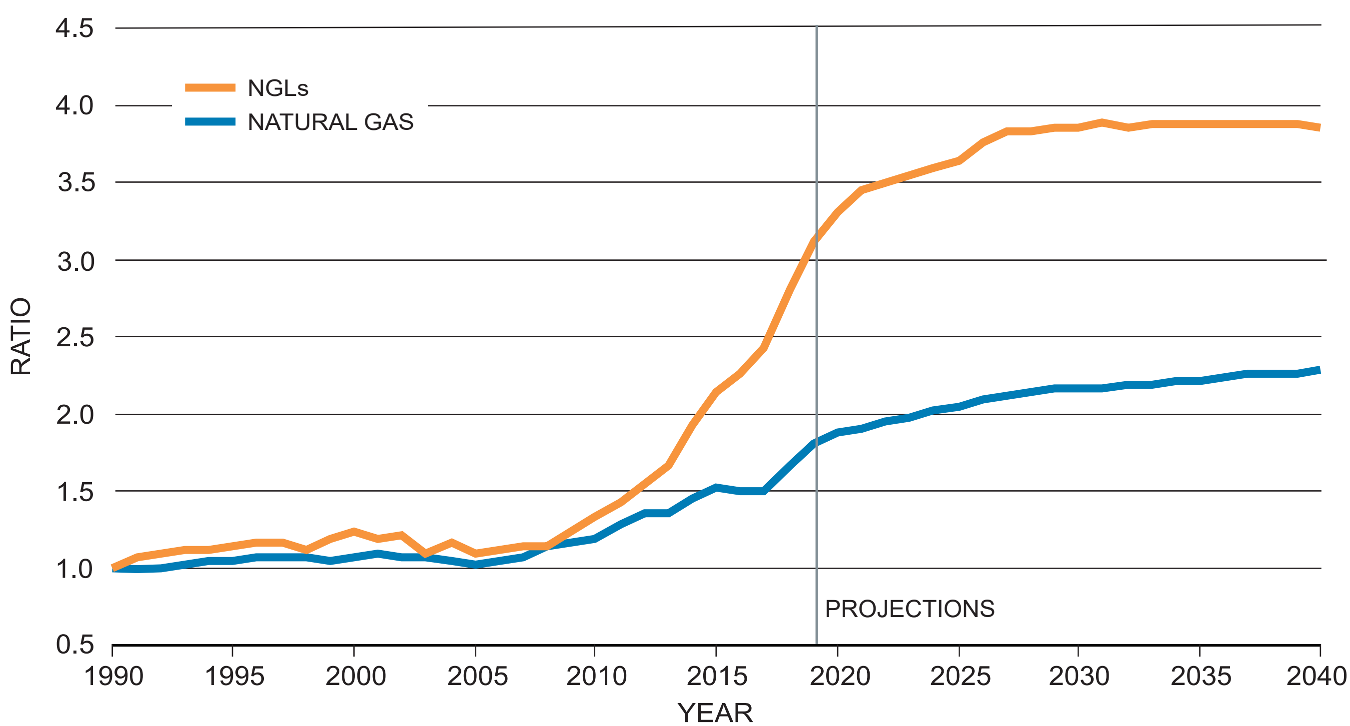
16 U.S. Energy Information Administration, *Annual Energy Outlook 2019*, p. 60, https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

17 U.S. Energy Information Administration, Natural Gas, Natural Gas Plant Liquids Production, February 13, 2018 release, https://www.eia.gov/dnav/ng/ng_prod_ngpl_s1_a.htm (accessed November 13, 2019).



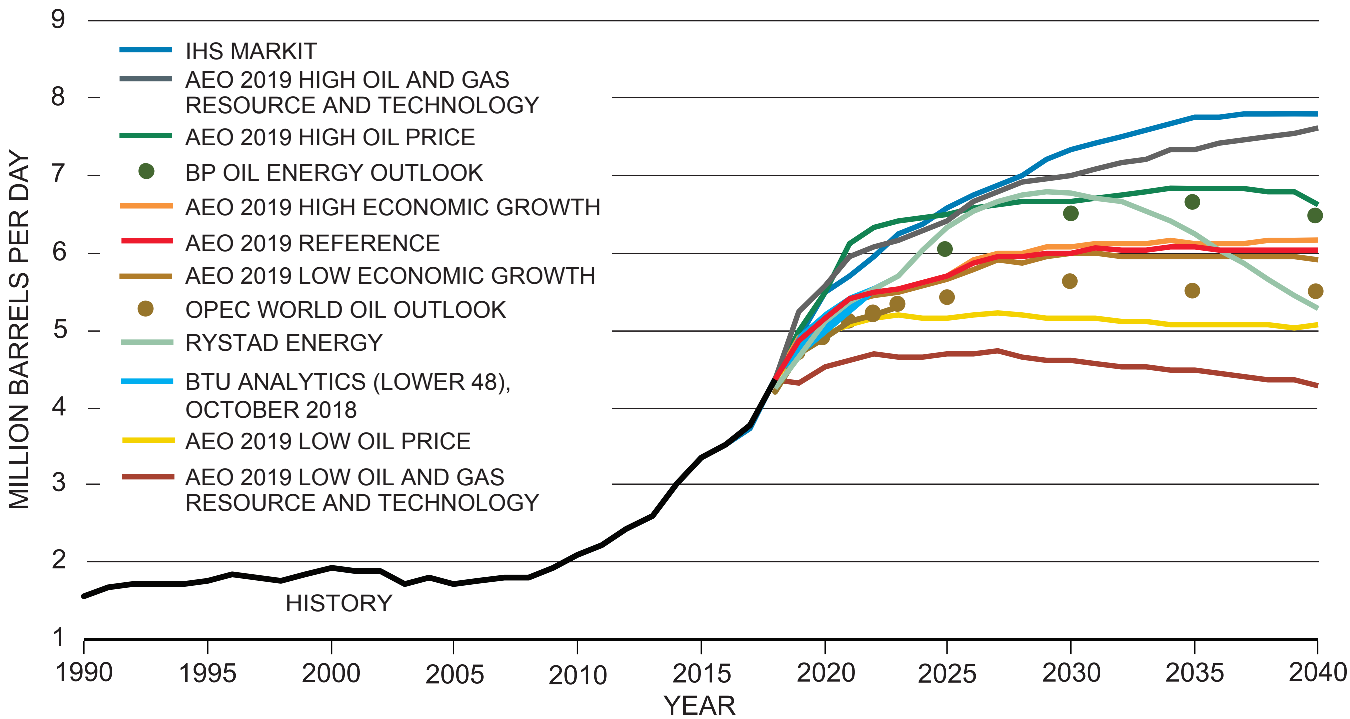
Source: EIA *Annual Energy Outlook 2019*, IHS Markit, and Rystad Energy.

Figure 1-17. *Gulf of Mexico Natural Gas Production Not Expected to Regain Previous Peak*



Source: EIA, *Annual Energy Outlook 2019*.

Figure 1-18. *Dry Natural Gas and NGL Production Relative to 1990*



Source: IHS Markit, EIA *Annual Energy Outlook 2019*, BTU Analytics 2018, Rystad Energy, OPEC *World Oil Outlook 2018,* and *BP Energy Outlook* 2019.

Figure 1-19. *Outlooks for Long-Term NGL Production Vary*

liquids is included with previously cited outlooks in Figure 1-19.[18]

a. Appalachian Basin (Marcellus and Utica) NGL Production

Appalachian Basin NGL production consists of supply from the Marcellus and Utica formations. Available forecasts that explicitly break out Marcellus and Utica NGL production anticipate continued growth through at least the early 2030s and, depending on the forecast, beyond (Figure 1-20).

The EIA does not explicitly break out NGL production in the Marcellus and the Utica (Figure 1-21). However, the EIA is consistent with available forecasts in anticipating most NGL supply development in the Marcellus, Utica, and Permian, writing "the large increase in NGPL production in the Reference case in the East (Marcellus and Utica plays) and Southwest (Permian plays) during the next 10 years is mainly caused by the close association NGPLs have with the development of crude oil and natural gas resources. By 2050, the Southwest and East regions account for more than 50% of total U.S. NGPL production."[19]

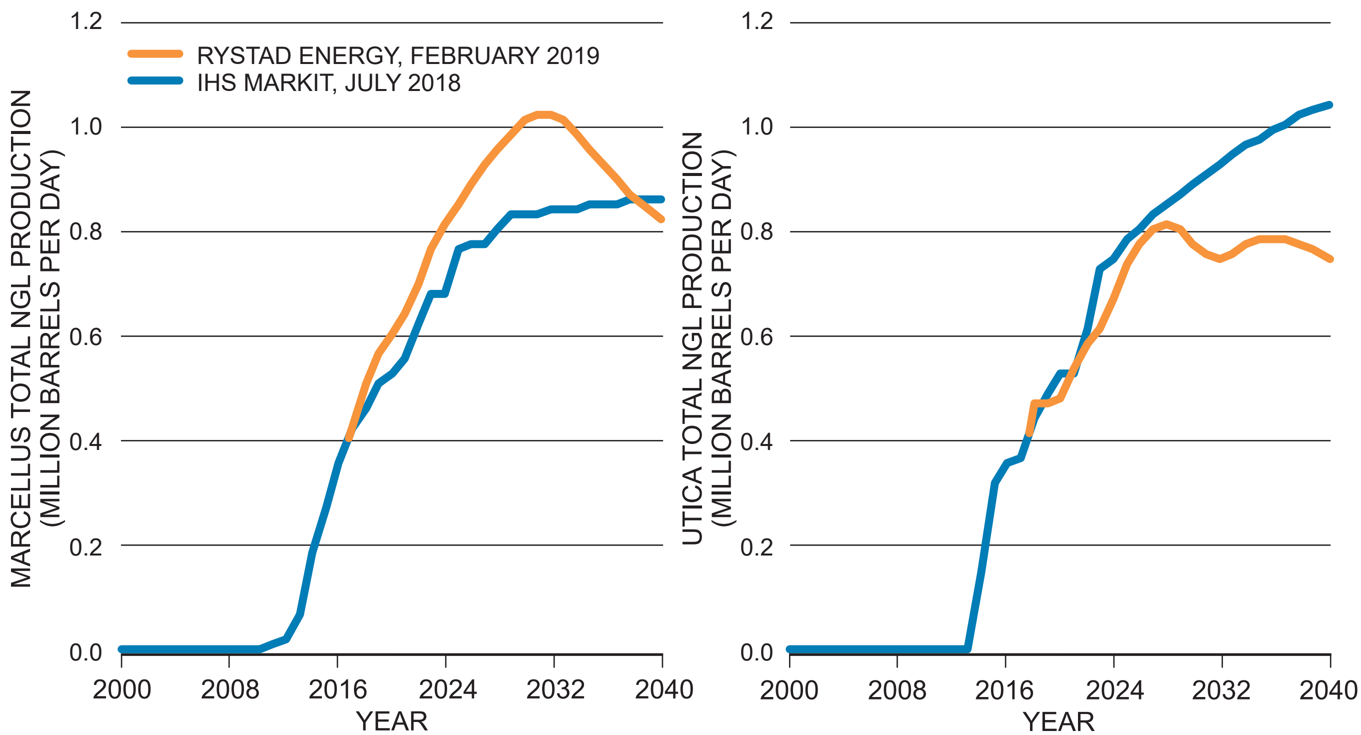
b. Permian Basin NGL Production

Available Permian Basin forecasts also anticipate NGL supply growth to roughly double 2018 production until at least the 2030s (Figure 1-22). As is the case elsewhere, this growth comes as a result of operators targeting crude oil and, to a lesser extent, liquids-rich natural gas.

Although the EIA does not break out Permian Basin NGL production, the Southwest region is a reasonable proxy for the Permian, and the EIA shows significant NGL production growth in the Southwest (Figure 1-23).

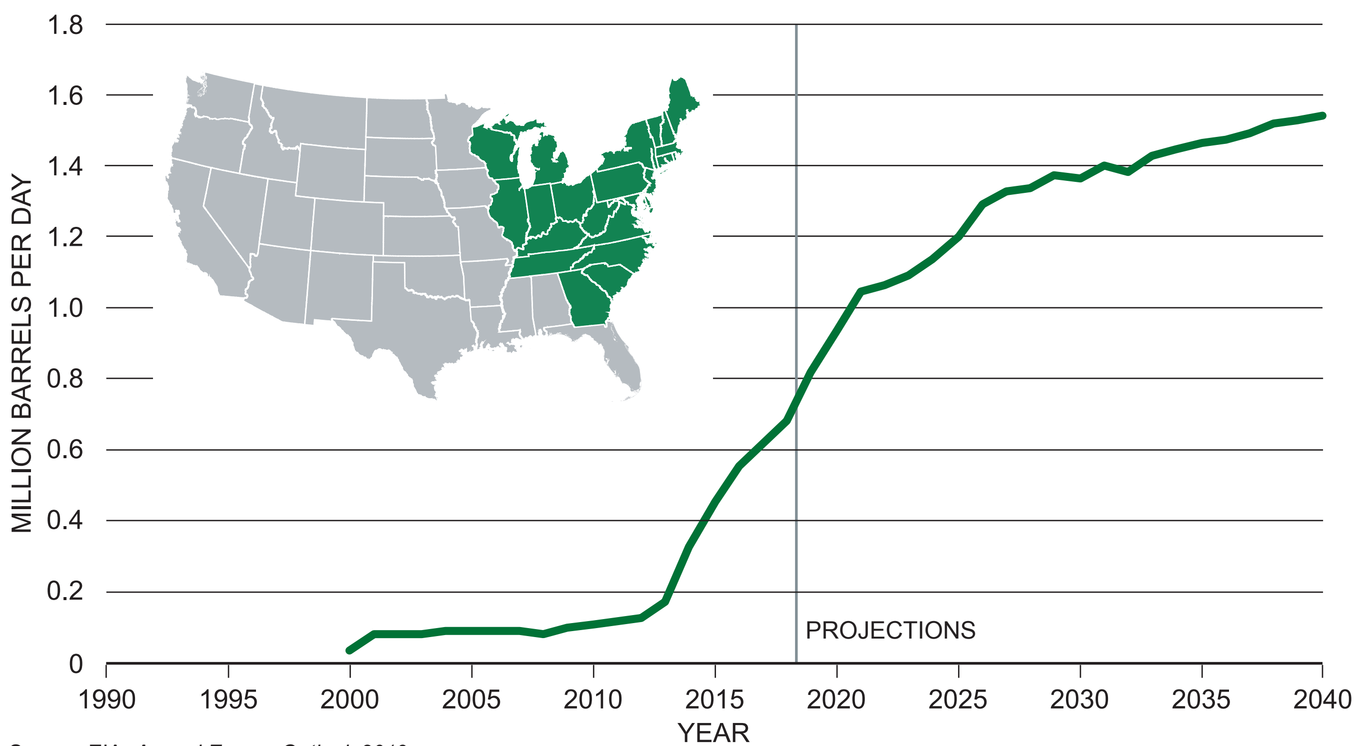
18 BTU Analytics, Long Term Gas Outlook, https://btuanalytics.com/products/long-term-gas-outlook/ (accessed November 13, 2019).

19 U.S. Energy Information Administration, *Annual Energy Outlook 2019*, p. 62, https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.



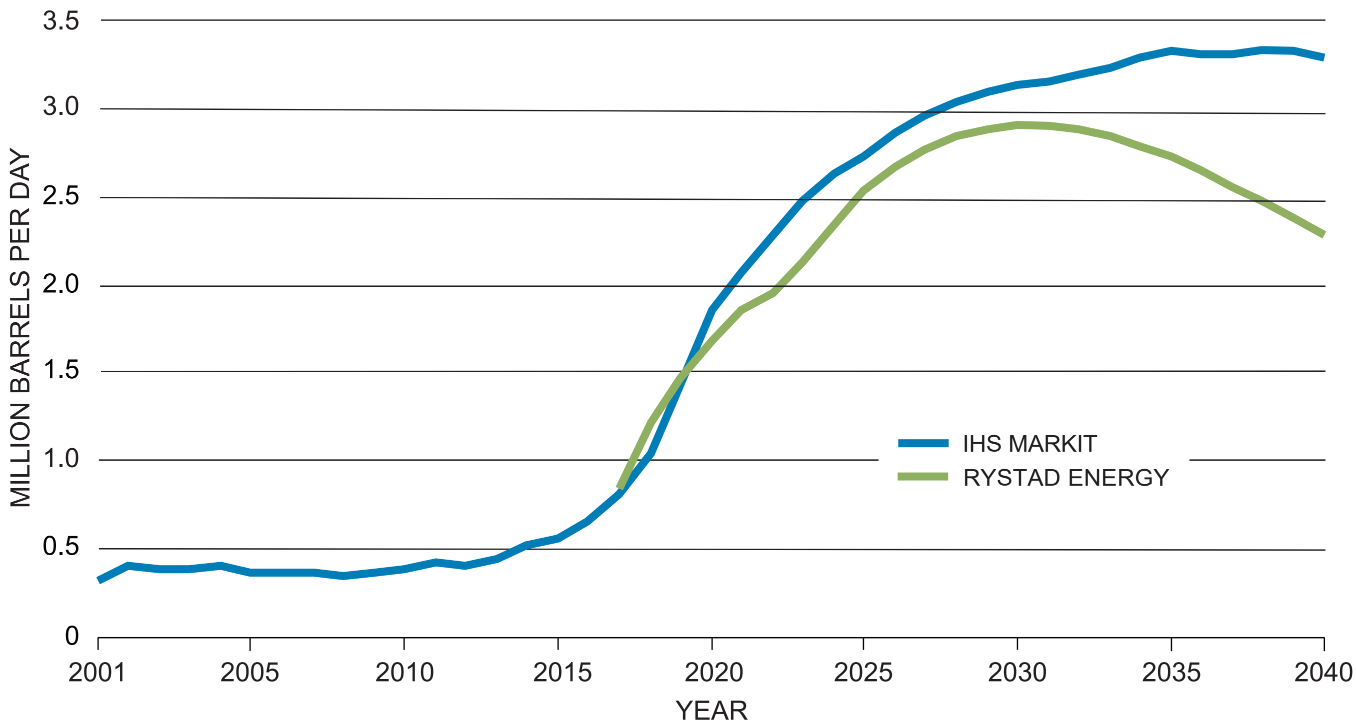
Sources: IHS Markit and Rystad Energy.

Figure 1-20. *Marcellus and Utica Expected to Be Sources of Long-Term NGL Production Growth*



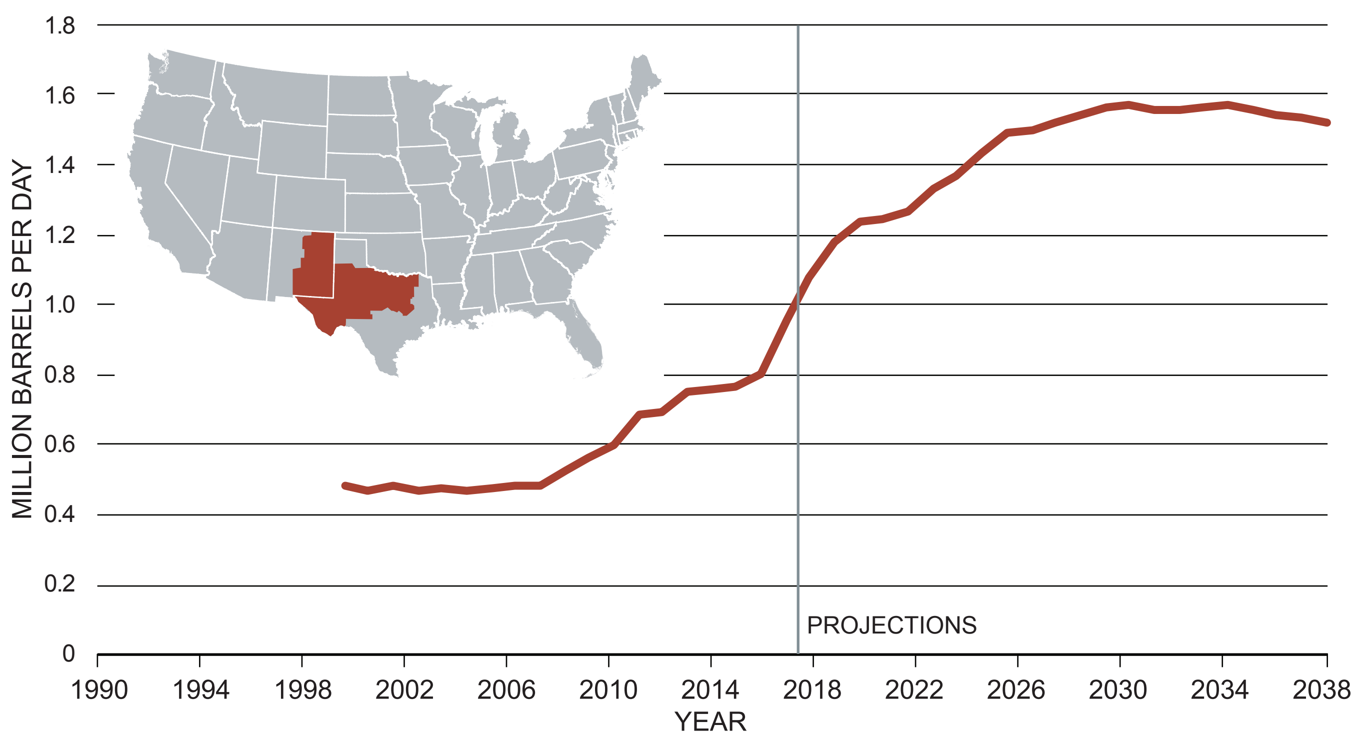
Source: EIA, *Annual Energy Outlook 2019*.

Figure 1-21. *EIA East Reference Case NGL Production*



Sources: IHS Markit and Rystad Energy.

Figure 1-22. *Permian Basin NGL Output Expected to Continue Rising through the 2020s*



Source: EIA, Annual Energy Outlook 2019.

Figure 1-23. *EIA Southwest Reference Case NGL Production*

Like the Marcellus and Utica, developers have significantly expanded NGL infrastructure in the Permian Basin to handle both the recent increase in Permian Basin NGL production and to get ahead of anticipated continued NGL production growth. According to RBN Energy,[20] "25 new Permian natural gas processing plants are expected to add about 5.0 BCF/D of new processing capacity, with more plant projects likely to be announced in the coming months."

Currently, there is approximately 1.7 MMB/D of NGL takeaway capacity out of the Permian Basin (Figure 1-24), but some of that capacity is used to transport NGLs from other areas through the Permian Basin and is not available for Permian Basin NGL production.

c. Other Basin-Level NGL Production

Today the Marcellus and Utica of the Appalachian Basin, and the Permian Basin comprise just under 40% of total national NGL production in available projections, a proportion expected to grow to between just under half to just above 60%, depending on the forecast. While significant, the Marcellus, Utica, and Permian are not the only important NGL production basins in the United States. Forecasts expect continued NGL production growth from the Bakken, Eagle Ford, STACK/SCOOP, Woodford, Niobrara, and, depending on the forecast, the Barnett.[21]

Publicly available infrastructure information is more limited for these areas, but growing NGL production will require more natural gas processing plants, NGL fractionators, and NGL transportation infrastructure, both Y-grade and for purity NGL products. Y-grade, also called mixed NGLs, or raw make, is an unfractionated blend of the various pure products that make up the NGL product family. A Y-grade stream is typically produced by a natural gas processing plant and transported by pipeline to a central fractionation facility to be split into purity products.

20 RBN Energy, "With a Permian Well, They Cried More, More, More," September 2017, https://rbnenergy.com/sites/default/files/static_pages/rbn_permian_ngl_dd_preview_20170913.pdf.

21 The SCOOP/STACK and Woodford plays are in Oklahoma.

III. DEMAND

A. Summary

Petroleum liquids and natural gas are the top two sources of U.S. primary energy consumption. Even in low-carbon scenarios discussed in this chapter, they remain the top two sources of primary energy consumption through at least 2040.

Forecasts show U.S. petroleum liquids demand as stable or slightly reduced due to increased engine efficiency and alternative fuel vehicles' market share increase with the exception of the IEA Sustainable Development Scenario, which shows a substantial reduction of liquids demand in the transportation sector. But there is a shift within the liquids demand mix as gasoline consumption decreases and distillates are forecast to remain stable or increase through 2040 as economic growth and air travel increase. Assuming minimal change in the current capacity, processing configurations, and utilization of U.S. refineries, net exports of refined products will increase.

U.S. natural gas demand has significantly increased in recent decades and is expected to continue this increase through 2040, driven in part by demand for natural gas in the electric power sector. The demand has been driven largely by abundant, inexpensive North American supply due to advances in shale extraction techniques. Low natural gas prices have supported fuel substitution in the power sector, easing the retirement of coal, oil, and nuclear power plants.

In the low-carbon scenarios evaluated, the largest energy sources continue to be oil and natural gas through at least 2040. IEA SDS, the most stringent scenario presented, predicts coal demand is reduced 84% to 87%, oil demand is reduced 42% to 47%, and natural gas demand is reduced 29% to 30% by 2040. In the carbon tax scenarios considered, the tax does little to reduce demand for oil-based transportation fuels.

B. Outlooks Reviewed

U.S. crude oil, refined product, and natural gas demand has evolved and grown since the mid-1800s, when crude oil was first commercially

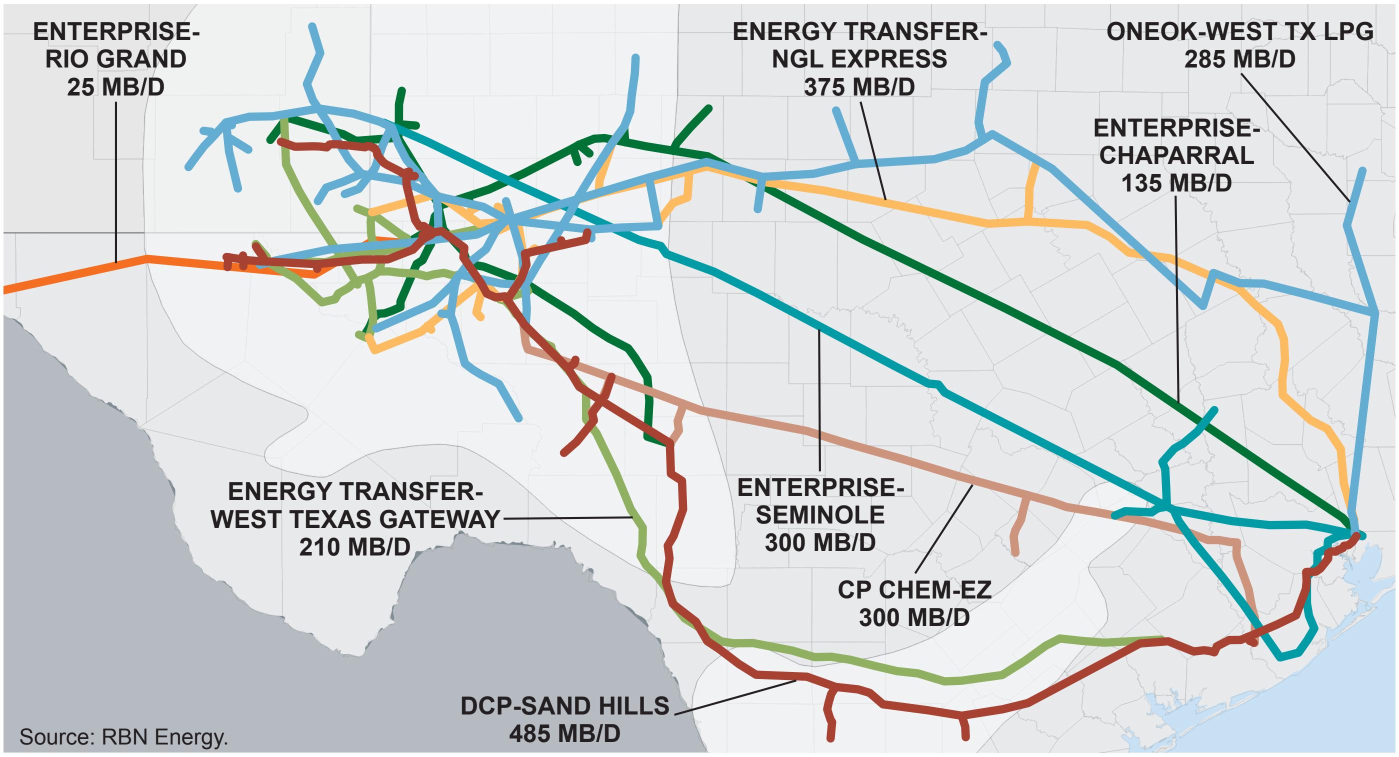


Figure 1-24. NGL Pipelines out of the Permian Basin

utilized. Most outlooks reviewed for this study show forthcoming changes in the consumption patterns for these commodities, with some experiencing strong growth while others decline.

For this study, no independent projections of demand were developed. Rather, publicly available projections from various third-party institutions were compared to facilitate a discussion on a range of potential outcomes, including outcomes in low-carbon policy scenarios. Petroleum commodity demand is driven by a variety of factors such as GDP growth, economic cycles, population growth, government infrastructure budgets, and pricing. Some of these assumptions have been noted in the descriptions of the projections detailed next. The level of growth is also influenced by government policy. The U.S. oil and natural gas industry is heavily regulated due to historical and future concerns over safety, energy security, and the environment. Some examples of major regulations include the Corporate Average Fuel Economy (CAFE) standards, which set minimum fleet average fuel economy (miles per gallon) requirements; the Renewable Fuel Standard, which mandates a minimum amount of renewable fuels that must be blended into transportation fuels; and Low Carbon Fuel Standards and other greenhouse gas regulations that are currently at the state level.

The various projections utilized in this review have varying assumptions on these key drivers. Notably, the assumptions and drivers of the projections made by the various groups have not been questioned or restated in this analysis. The analysis purely focuses on the respective outlooks for the fuels produced by the forecasting organizations.

The following outlooks are included in the forthcoming discussion:

- **EIA *Annual Energy Outlook 2019***
  - **Reference Case:** Assumes current laws and regulations remain unchanged. GDP grows at 1.9% annually and Brent crude

oil reaches $108/barrel in 2018 dollars by 2050. Increases in fuel economy standards cause a 26% decline in gasoline consumption between 2018 and 2050 and diesel consumption growth stagnates.

  - **High Oil Price Case:** Assumes Brent crude oil reaches $211/ barrel in 2018 dollars by 2050.
  - **Low Oil Price Case:** Assumes Brent crude oil reaches $50/barrel in 2018 dollars by 2050.

- **IEA *World Energy Outlook 2018***
  - **Current Policies Scenario:** Captures global policies as of mid-2018 and assumes laws and regulations do not change over time. Utilized in the discussion on carbon scenarios.
  - **New Policies Scenario:** Incorporates existing energy policies as well as an assessment of the results likely to stem from the implementation of announced policy intentions. These policies include the Nationally Determined Contributions countries agreed to under the Paris Agreement. U.S. GDP growth is assumed to be 2.0% annually. IEA crude oil price reaches $112/ barrel in 2017 dollars by 2040.
  - **Sustainable Development Scenario:** The IEA SDS is fully aligned with the Paris Agreement, which seeks to limit global average temperature rise to less than 2°C, and outlines an integrated approach to achieving (1) internationally agreed objectives on climate change as laid out in the Paris Agreement. This assumes global greenhouse gas emissions peak by 2020 and then decline rapidly, with net-zero emissions by 2070; (2) dramatic reductions in health impacts due to energy-related air pollution; and (3) universal access to modern energy by 2030. IEA crude oil price reaches $64/barrel in 2017 dollars by 2040.

- **IHS Markit 2019 Rivalry Scenario:** The IHS Markit oil and natural gas demand outlooks in the Rivalry scenario are part of a detailed global energy demand, supply, and market outlook. Global market context is a critical influence on U.S. trends. Rivalry posits an intense competition for energy market share—an energy "rivalry." Suppliers of oil, natural gas, coal, nuclear power, and renewable energy compete to preserve traditional markets or dethrone incumbents. Oil prices are generally moderate, but volatile. Global oil demand grows until it hits a plateau in the latter half of the 2030s. In the United States, a combination of market forces and commercially driven innovation plays a primary role in transforming the personal transportation trends, especially in large cities. Demand for refined products declines gradually in the early 2020s owing to higher fuel economy standards for cars and light trucks, as well as heavy-duty fuel economy standards. The expansion of new mobility services helps drive demand for electric vehicles. Sales of gasoline-only light duty vehicles in 2040 are almost 80% lower than in 2018. U.S. natural gas demand in Rivalry generally rises through 2040. Natural gas-fired power plants increasingly dominate power generation, as environmental constraints result in large renewable capacity additions (wind and solar) and a growing number of coal plant retirements. Increasing renewable generation also requires backup from natural gas.

- **Wood Mackenzie 2019:** Wood Mackenzie's demand projections assume that a more efficient, hydrocarbon-led economy is on the horizon. GDP expands by just under 2% through 2040, weighted toward services. This, combined with the build out of renewables in the power sector, higher efficiency rates for the internal combustion engine, and modern heating and lighting solutions, pushes energy intensity ~40% lower by 2040. In contrast to other markets (e.g. Europe, Canada), this is achieved in a carbon policy light environment, where a federal carbon tax of $2/metric ton (tonne) in the power sector is included from 2028, building to approximately $30/tonne by 2040. A low-cost resource base supports hydrocarbon demand, with gas and oil accounting for the majority of the energy mix. The world's largest gas producer will be its largest consumer—fueling a globally competitive industrial base, meeting peak power demand, and filling a critical gap as coal, nuclear decline. Oil demand peaks around 2025 in the United States—roughly 10 years earlier than Wood Mackenzie's global forecast—but it will be key to meeting transport, heating, and industrial demand.

- **BP 2019 Energy Outlook, Evolving Transition Scenario:** U.S. primary energy consumption plateaus, with no overall growth between 2017 and 2040. Oil consumption declines by 1% per year, while natural gas and renewable consumption grows at 1.1% and 4.9% per year, respectively. Improvements in vehicle efficiency cause energy use in transport to fall by 0.7% per year from 2017 to 2040.

- **Federal Aviation Administration Outlook:** Utilized for jet fuel consumption only.

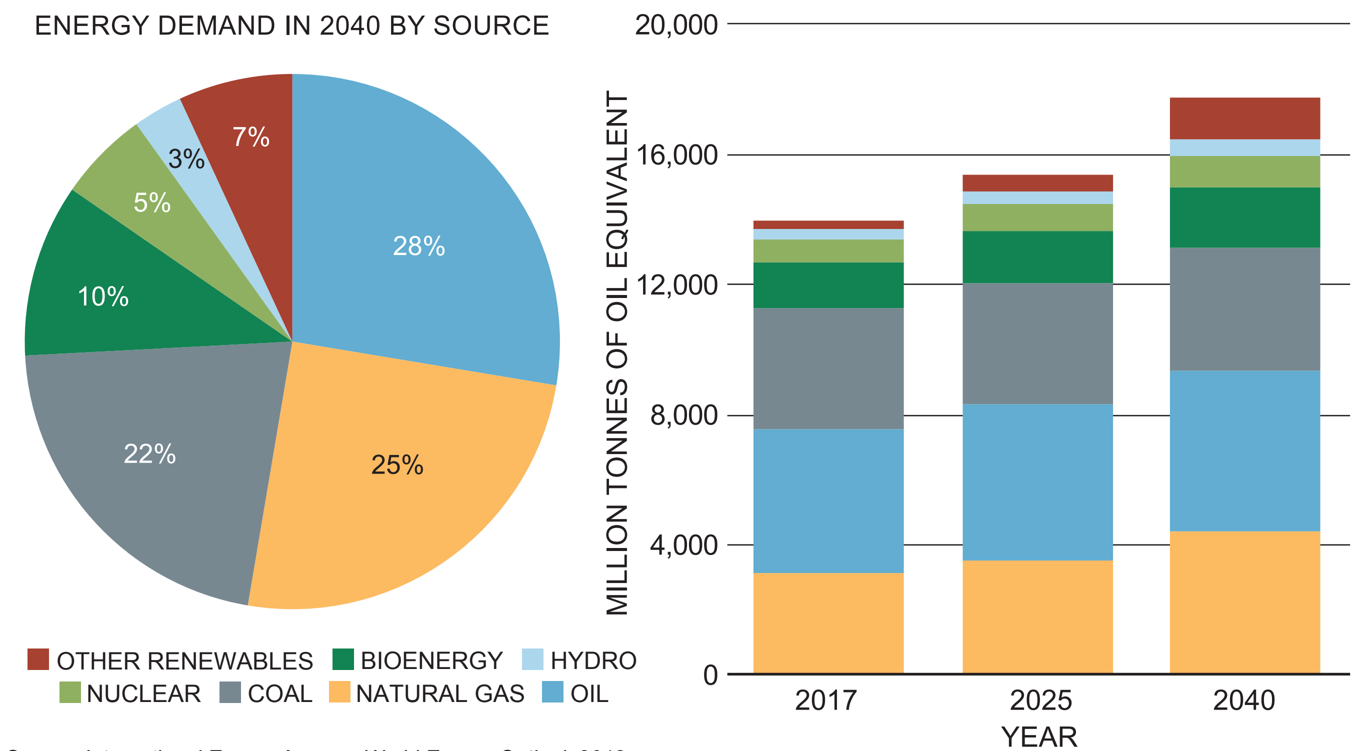
- **Rhodium Group and Columbia University's Center on Global Energy Policy** report, *Energy and Environmental Implications of a Carbon Tax in the United States,* provides two economy-wide domestic carbon tax scenarios as well as projection of business-as-usual: A $50/tonne carbon dioxide equivalent (CO_2e) tax that rises at an approximately 2% real rate annually beginning in 2020; a $73/tonne CO_2e tax that rises at an approximately 1.5% real rate annually beginning in 2020; and a reference case based on reference case projections from the EIA's 2017 AEO. The tax scenarios assume the tax applies to domestic CO_2 emissions that occur from the combustion or consumption of fossil fuels as well as methane emissions that occur during the production of oil and natural gas. The tax is applied in the model to each fuel just after the wholesale transaction occurs. For imported fuels, the tax applies after the fuel is imported. This analysis assumes that the carbon tax revenue is recycled back into the U.S. economy and is not used to support specific policies that could accelerate emission reductions.

C. World Energy Demand Growing

While this report focuses on the U.S. oil and natural gas industry, it is important to understand supply and demand dynamics globally, since the United States has increasingly become a supplier of commodities to the world. As shown in Figure 1-25, in the 2018 World Energy Outlook (WEO) New Policies Scenario, the IEA forecasts that the world is going to require an additional 3,741 million tons of oil equivalent (Mtoe) of energy between 2017 and 2040, a 27% increase over the 13,972 Mtoe of energy consumed in 2017. Of this forecast growth, 48% will come from natural gas and oil. In fact, natural gas will provide the largest source of energy growth, slightly outpacing renewables growth, with oil being the third largest source of energy growth. Compared to 2017 world demand levels, natural gas demand will grow by 43% and oil demand will grow by 10%. Despite this rapid pace of growth, due to growth in renewables and emission free sources of energy, the combination of natural gas and oil will make up a slightly lower percentage of total demand in 2040, with the proportion of total energy falling from 54% in 2017 to 53% in 2040. Emission free sources of energy provide 15% of the total demand by 2040.

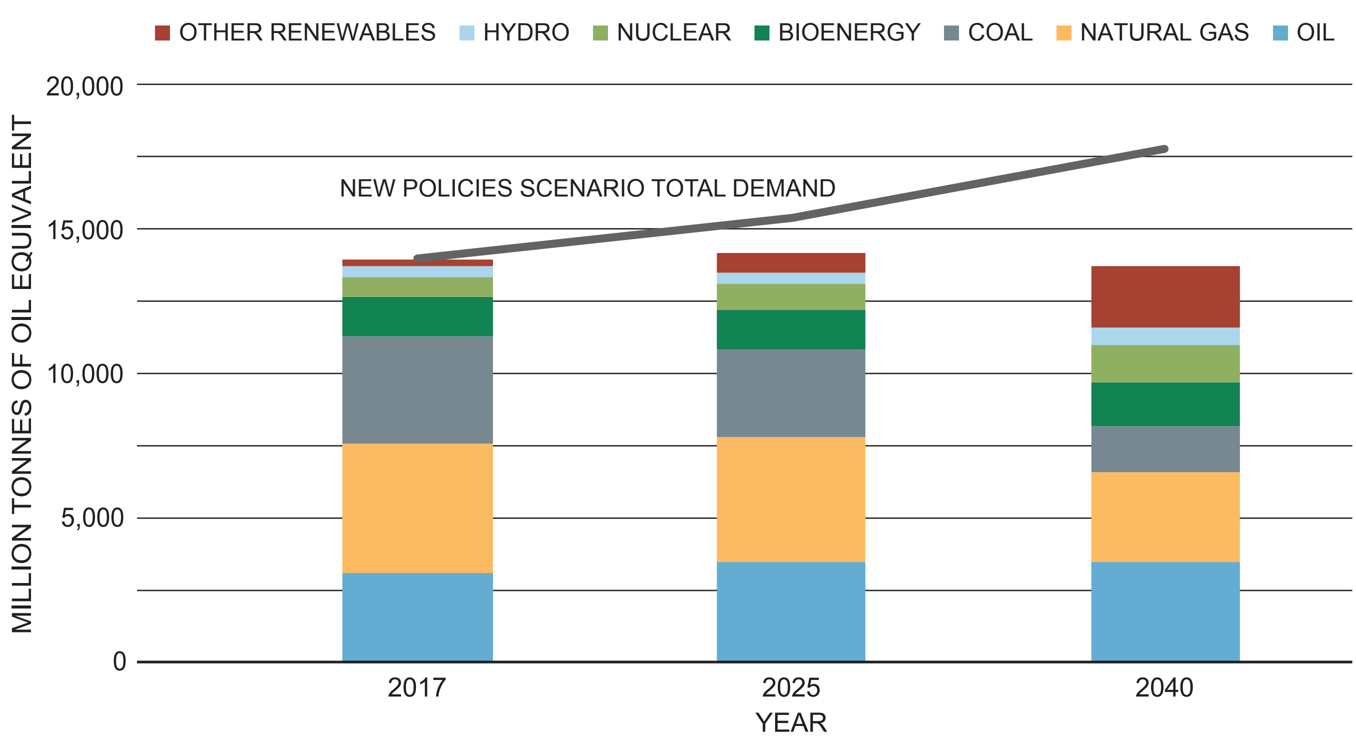
This projection directionally aligns with EIA's 2017 International Energy Outlook Reference Case that projects total world demand for energy will grow by 25% through 2040. The EIA forecasts that natural gas will be the largest growing source of energy, with demand growing by 41% over 2017 levels. The EIA also forecasts that there will be an increasing need for oil, as this energy source grows by 15%, allowing it to remain the single largest source of energy, providing 31% of all the energy consumed in 2040, which is slightly higher than the 28% that is forecast in the IEA New Policies Scenario, previously.

Even in a carbon-constrained scenario, demand for natural gas and oil will remain robust. The IEA SDS shown in Figure 1-26 forecasts such a situation. Compared to the New Policies Scenario, a major transformation of the global energy system takes place over the outlook time period. Due to energy efficiency initiatives, total demand for energy only increases by 1% from 2017 to 2025, and declines marginally thereafter, dropping by a net 2% by 2040. Coupled with this relatively lower demand for energy, a transition to renewable energy, nuclear power, and bioenergy offset a 705 Mtoe reduction in coal demand through 2025. Over this same time period, natural gas demand increases by 11%, so oil and natural gas actually increase their combined proportion of total energy demand from 54% in 2017 to 55% in 2025. Beyond 2025, continued transition to lower emission energy sources replaces additional demand for oil and coal, but demand for natural gas remains constant, making it the single largest source of energy by 2040. Despite a net 949 Mtoe reduction



Source: International Energy Agency, *World Energy Outlook 2018*.

Figure 1-25. *World Energy Demand per the IEA New Policies Scenario*



Source: International Energy Agency, *World Energy Outlook 2018*.

Figure 1-26. *IEA WEO 2018 Global Demand by Source, Sustainable Development Scenario* in demand for oil and natural gas by 2040, these energy sources still comprise 48% of the global energy system, compared to 29% from emission free sources.

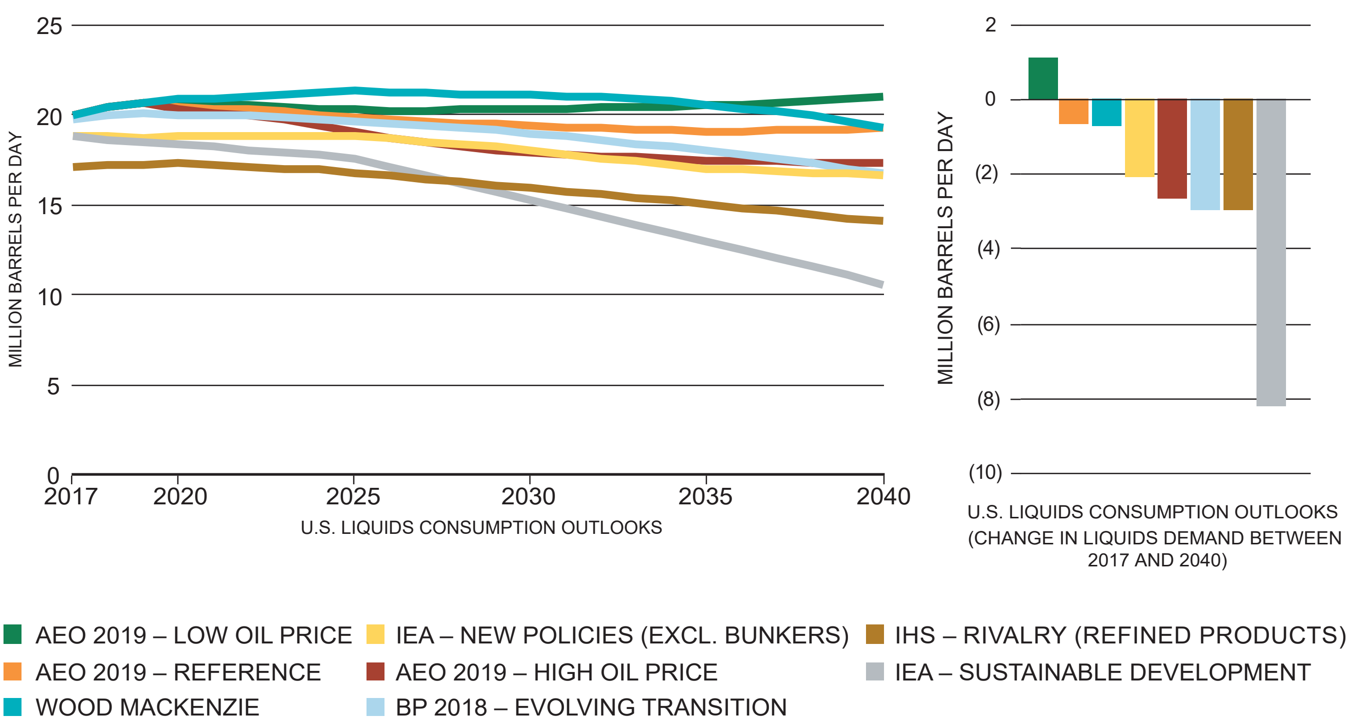
The United States as the leading producer of energy in the world will continue to play a large role in international trade. Increasingly, that role will be as a net exporter of natural gas, light crude oils, and finished products (gasoline, diesel, ethane, propane, etc.)

D. U.S. Crude Oil and Refined Products Consumption

The general view from all the forecasts reviewed is that, in total, U.S. liquids demand will decrease moderately between 2017 and 2040 (Figure 1-27). Of the projections reviewed, the only scenario that shows an increase in refined product demand is the EIA Low Oil Price scenario. In that case, total liquids demand increases approximately 1 MMB/D over the period. Under a high oil price, the reduction in refined product demand is projected to be more pronounced. The EIA High Oil Price case shows a reduction in U.S. liquids demand of more than 2.5 MMB/D. Policies that limit carbon emissions can also impact demand. While the carbon tax scenarios examined for this chapter project limited impact on demand for refined products, the more stringent policies modeled by the IEA in its SDS predict demand for traditional transportation fuels will be cut by more than 50% by 2040, when compared to a scenario that models no change in current policies.

The outlooks on U.S. liquids consumption shown in Figure 1-27 are not all on the same basis.[22] For example, some of the outlooks do not start at the same liquids-consumption level in 2017, which would be a historical data point. This is due to the exclusion of certain product categories from data, such as bunker fuel in the IEA New Policies

22 The forecasts in Figure 1-27 measure three different groups of liquids. Some measure all liquids, two exclude bunker fuels, and one is finished products only. Due to these various measures, as well as differences in each forecasting group's methodologies, there are differences of opinion on the 2017 historical U.S. consumption. The vintages of the forecasts have been included in the labels of the series.



Sources: EIA *Annual Energy Outlook 2019*, IHS Markit, IEA *World Energy Outlook 2019*, Wood Mackenzie, and BP *Energy Outlook 2019*.

Figure 1-27. *Total Liquids Demand Curves from Various Sources*

Scenario. In addition, the IHS Rivalry Scenario is for refined products only.

For individual refined transportation fuels, the projections generally show flat to declining demand, with most of the reduction in demand in the gasoline market. The exception to this trend is jet fuel, which increases an average of 2% annually over the period. While there is an increase of renewable energies in the mix, there is not a significant increase in the penetration of renewables into the transportation fuels markets over the period under current policy outlooks.

1. Crude Oil Demand for Refineries

The EIA forecast shows a modest net growth in refinery capacity of 500,000 B/D over the period, assumed to be in Petroleum Administration for Defense District (PADD) 3. Assuming regional aggregate refinery capacity and yields remain at current levels, or only experience small growth, movements of refined products between U.S. regions would decrease, and net exports of refined products would increase. The evolving dynamics for gasoline demand will dramatically change the net import/export balance for that fuel. Although a portion of the naphtha yield (a component used to make gasoline) can be channeled to make diesel and jet fuel, the net effect of declining gasoline demand in the United States will be a requirement for increased exports of gasoline to international markets to maintain those high crude oil runs.

It is noted that the Northeast is highly dependent on the U.S. Gulf Coast refining complex and relies on two main products pipelines, Colonial and Plantation, that carry product from PADD 3 up the entire Eastern seaboard to New York. These two pipelines are seasonally at capacity, and PADD 1 refining only contributes 1 MMB/D locally versus a regional 5.5 MMB/D of consumption. Therefore, the East Coast will remain dependent on waterborne imports of refined products to meet the demand balance.

As noted previously, jet fuel demand continues to increase, and there is a significant concern that many major airports are served either wholly by truck, or by a single pipeline designed originally for much lower volumes, thus the jet fuel supply chain is vulnerable and unprepared for the next two decades of growth.

Refineries are sophisticated industrial facilities that turn crude oil into refined products, such as gasoline, jet fuel, and diesel, among other things. In 2018, the United States had 135 refineries with 18.6 MMB/D of operable refinery capacity and operated at 93.2% utilization.[23]

The crude oil feedstock processed in these facilities is sourced from both the domestic producing basins reviewed in the supply section of this chapter as well as from international sources.[24] While domestic crude oil production has increased dramatically since the late 2000s, the United States does not produce enough crude oil, either in volume or quality, to meet the requirements of the installed refining capacity. The relationship between oil quality and refinery output is described in the text box titled "Vignette: Crude Oil Quality." The production growth in the United States has been driven by domestic shale oil plays, which has predominantly been of the light (>35° API) and sweet (<0.5% sulfur) quality. This production growth has helped to reduce imports of similar quality crude oils but has hit processing and logistical constraints within the refining system, limiting further increased processing.

In the United States, most of the crude oil required to feed these facilities flows through an expansive pipeline network due to geographic differences between domestic production/import locations and refinery locations (Figure 1-28). However, this pipeline network is most extensive in the central part of the country, enabling movements of domestically produced crude oil to centrally located refineries within the region or export ports along the U.S. Gulf Coast.

Notably, the U.S. East Coast (commonly referred to as PADD 1) does not have pipeline connectivity to any domestically produced crude oil. This is a

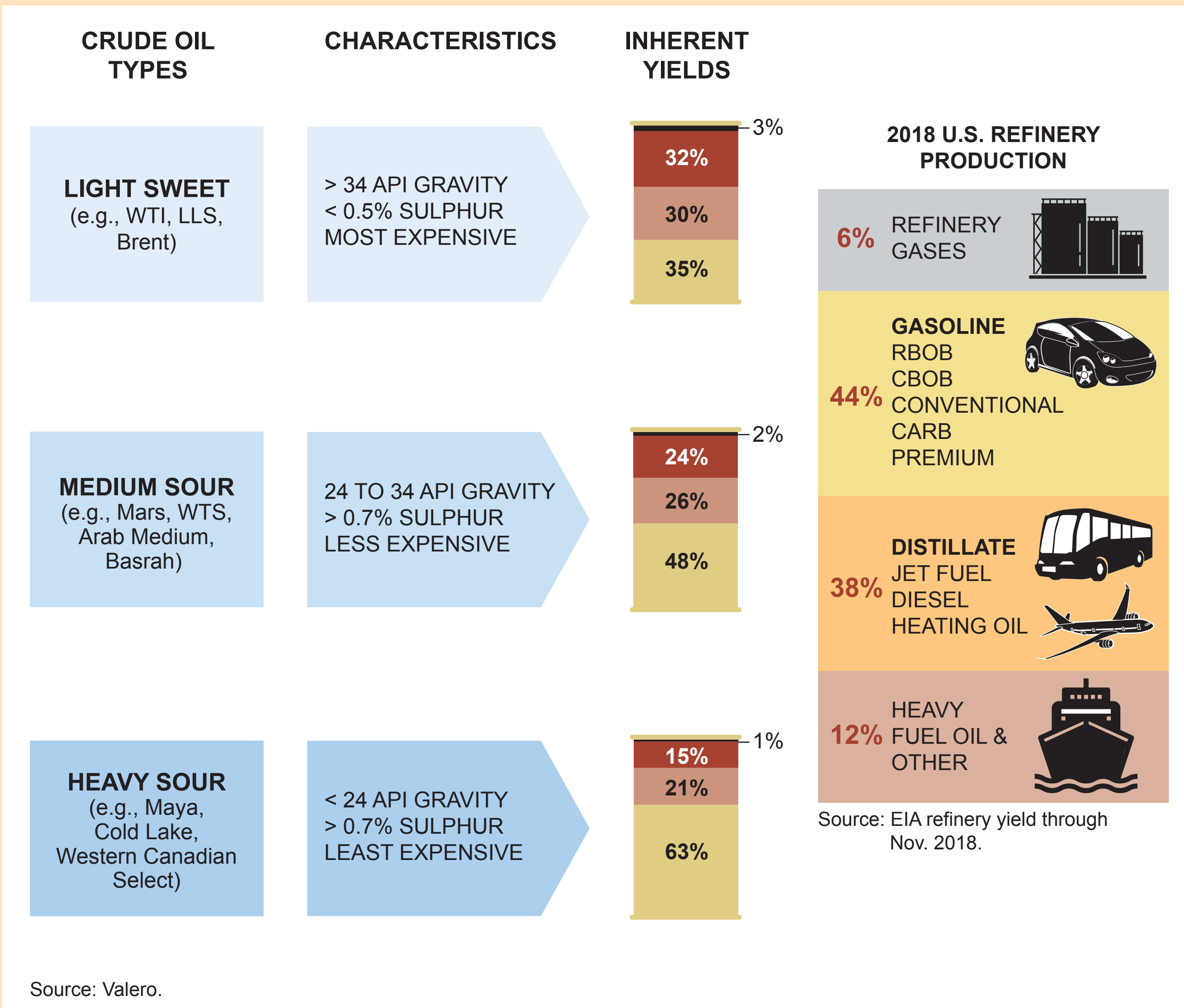
23 U.S. Energy Information Administration, Petroleum & Other Liquids, "Refinery Utilization and Capacity," https://www.eia.gov/dnav/pet/pet_pnp_unc_dcu_nus_a.htm (accessed October 24, 2019).

24 Crude oil accounts for approximately 91% of total inputs to the U.S. refining system, with the balance largely comprising unfinished feedstocks.

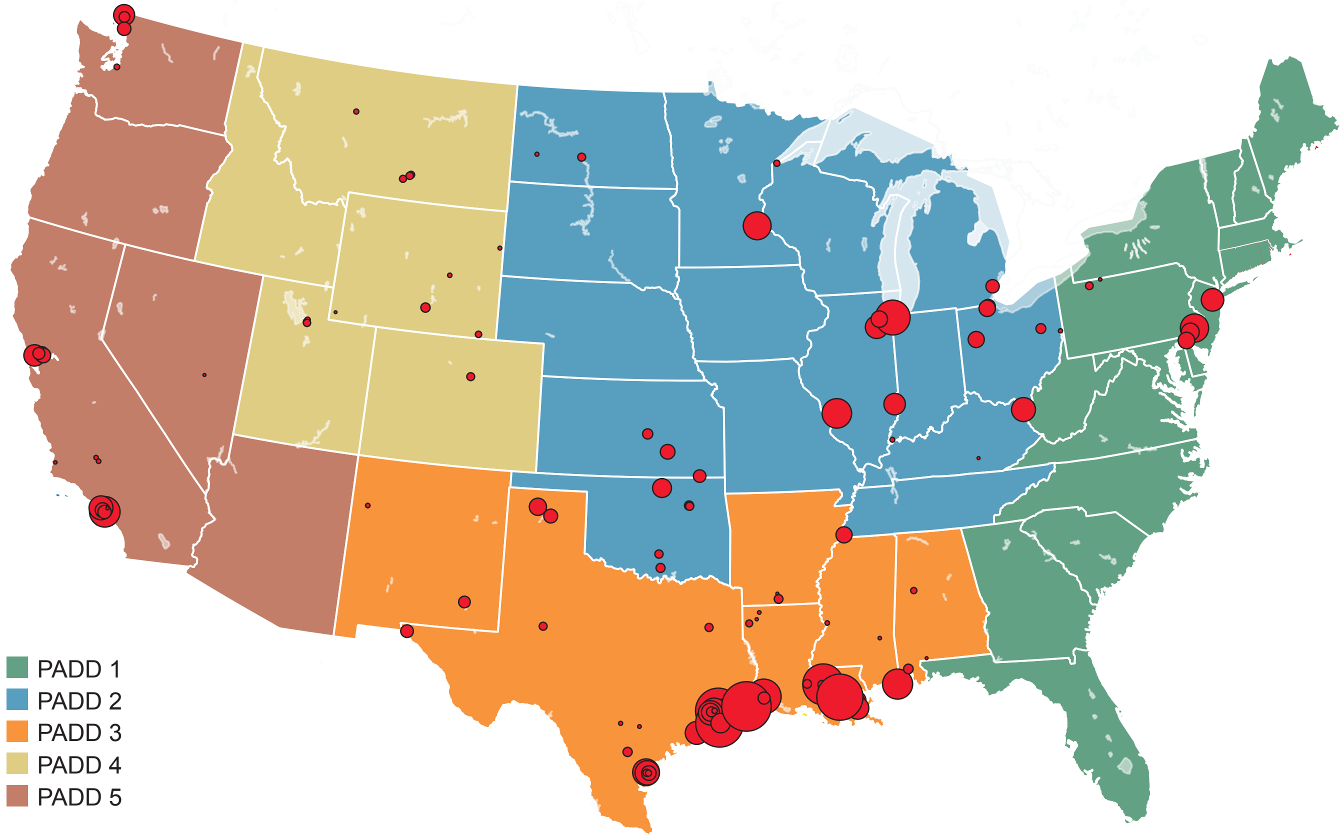
VIGNETTE: CRUDE OIL QUALITY

Crude oil quality varies between producing regions and potentially between wells in the same region. While there are a variety of quality characteristics important to refiners, most crude oils are described in terms of their API gravity and sulfur content. API gravity is an inverse measure of a petroleum liquid's density relative to that of water. A light crude oil has a high API gravity (more than 35°) while a heavy crude oil would have a low API gravity (less than 24°). Sulfur content of crude oil is typically described by the terms "sweet" (less than 0.5% sulfur) and "sour" (greater than 0.5% sulfur).

Refineries are designed and configured to process a mix of crude oils that blend into a certain quality range. Heavy sour crude oils produce a higher yield of heavy fuel oil, while light sweet crude oils produce a higher yield of gasoline and diesel fuels. Refineries that have added bottoms upgrading units, such as cokers, have the ability to use a heavy sour feedstock since they can upgrade the heavy fuel oil into more valuable refined products. The figure below illustrates the inherent yields of crude oils with different characteristics.



Yields from Various Crude Oil Types



Source: EIA, U.S. States, U.S. Energy Mapping System (with modifications for PADD boundaries and shipping routes).

Figure 1-28. *U.S. Crude Oil Production Regions and Refineries*

structural disadvantage for refiners in the region that wish to access domestic crude oil sources since the feedstock must move via alternative, and generally more expensive, methods, such as rail or Jones Act marine vessels.[25] Similarly, the U.S. West Coast (commonly referred to as PADD 5) also does not have pipeline connectivity to the major production regions in the country. While California does produce crude oil in the San Joaquin Valley, the quantity and quality produced is not enough to satisfy the refiner consumption in that region. Similar to the East Coast, alternative forms of delivery through either rail or Jones Act vessel must be utilized to receive domestically produced crude oil. Figure 1-29 summarizes the share of domestic versus imported crude oils processed by U.S. refineries in 2018.

Of the outlooks utilized in this study, only the EIA's 2019 AEO provided detail on expected crude oil runs in U.S. refineries. Refinery capacity is not projected to increase significantly, with the EIA only including 500,000 B/D of capacity expansion through 2040. This amount of capacity addition would be below the 127,000 B/D added on average over the past 20 years.[26] This is important to highlight because it caps the incremental amounts of domestic shale crude oil production that can be processed in the United States without price incentives, configuration changes, or increased logistical connectivity. Based on trends in production highlighted in the supply section of this chapter, limited refinery capacity additions, and the current configuration of the refineries, the United States is expected to continue to import a portion of the crude oil required for domestic refinery feedstock and crude oil

25 See topic paper associated with this NPC study that describes the Jones Act: "The Merchant Marine Act of 1920."

26 U.S. Energy Information Administration, Petroleum & Other Liquids, "U.S. Refinery Operable Atmospheric Crude Oil Distillation Capacity," https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=8_NA_8D0_NUS_4&f=A (accessed October 24, 2019).

exports should continue to grow with increasing production.

Finding: Assuming minimal change in the current capacity, processing configurations, and utilization of U.S. refineries, net exports of refined products will increase.

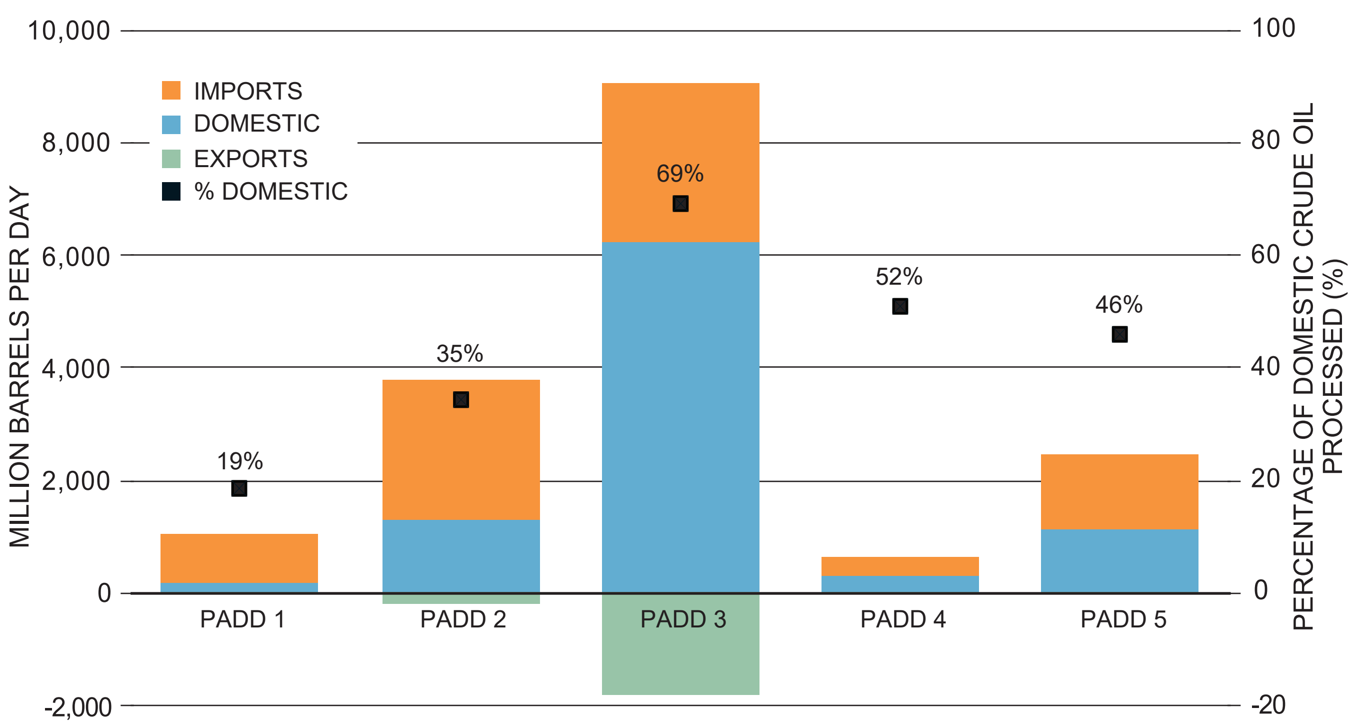
Finding: Due to the increase in U.S. crude oil production, crude oil imports have declined but have not been completely displaced. Despite domestic crude oil production growth forecasts, imports will continue in the United States due to (1) quality requirements of U.S. refineries and (2) locational discrepancies between production regions and certain refining regions.

The quality of the increased domestic production is not expected to be compatible with the current U.S. refinery configuration and, therefore, will not displace imports completely. Due to the configuration and high complexity of the U.S. refining complex, particularly in PADD 3, the U.S. Gulf Coast, and PADD 2, the Midwest, there will still be an appetite for heavy, sour barrels to be imported, and domestic sweet crude oil to be increasingly exported as production grows.

2. Refined Products

Refineries produce numerous finished, specialty, and intermediate products from their feedstocks, all of which have to be transported through some form of logistical infrastructure to their next point of consumption. While liquids consumption will be discussed in the overall aggregate context, the scope of analysis has been narrowed for individual refined products to transportation fuels such as gasoline, jet fuel, diesel, residual fuel oil, and renewable fuels such as ethanol, biodiesel, and biojet. These refined products made up more than 88% of the refined products consumed in the United States in 2018.[27]

27 U.S. Energy Information Administration, Petroleum & Other Liquids, "Supply and Disposition," listings for Finished Motor Gasoline, Kerosene-Type Jet Fuel, Distillate Fuel Oil, and Residual Fuel Oil supply, https://www.eia.gov/dnav/pet/pet_sum_snd_d_nus_mbblpd_a_cur.htm (accessed October 24, 2019).



Source: EIA, Petroleum & Other Liquids, "Refinery Receipts of Crude Oil by Method of Transportation, Foreign and Domestic."

Figure 1-29. *2018 Share of Domestic and Foreign Crude Oil Processed in Refineries by PADD*

Due to varying ways that historical and projected data are reported by agencies, the following analysis will be viewed from the country, PADD, and census region levels. A census region map with a PADD boundary overlay has been provided for reference in Figure 1-30.

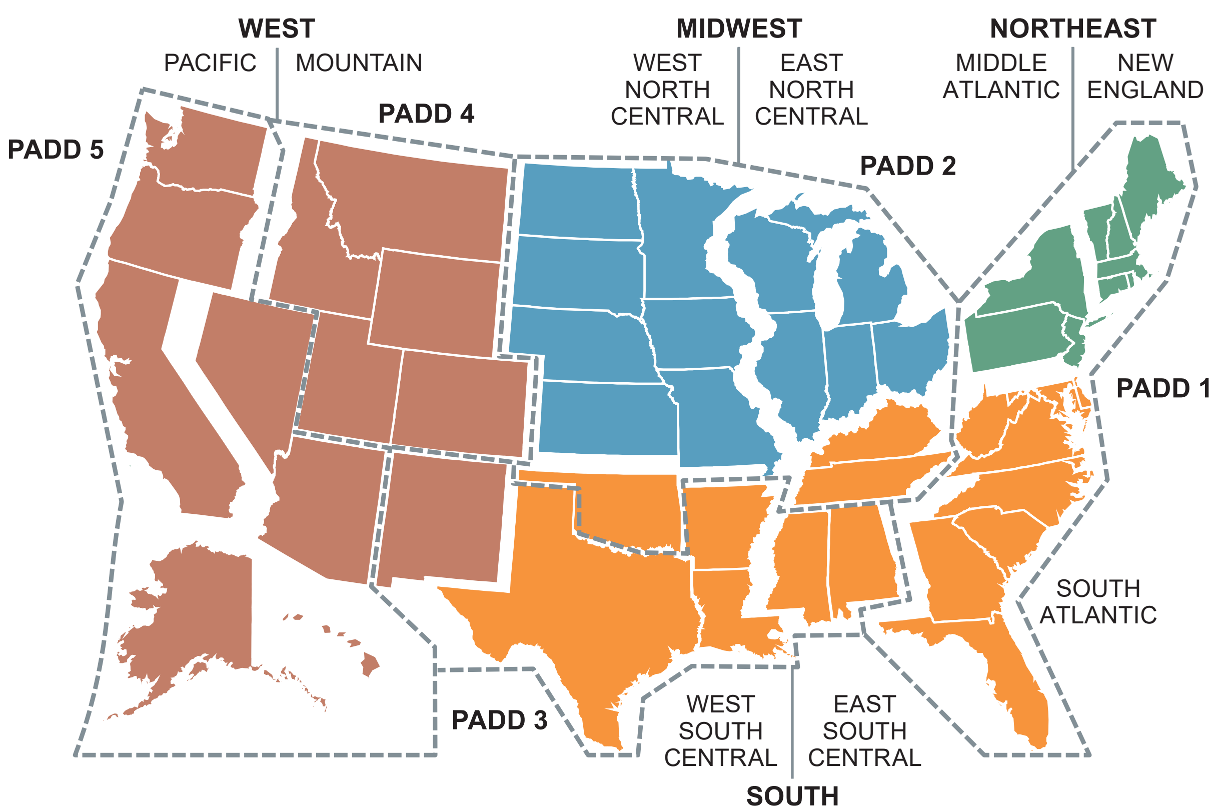
a. Gasoline, Including Ethanol

U.S. finished gasoline consumption, which includes ethanol blended, increased from 5.8 MMB/D in 1970 to 9.3 MMB/D in 2018, representing a 1.0% compound annual growth rate (Figure 1-31). Ethanol currently comprises slightly more than 10% of the gasoline pool, leaving 90% of the gasoline to be supplied by refineries.

PADD 1 is the largest consuming region, with 36% of U.S. consumption in 2017, followed by PADDs 2 and 5 (Figure 1-32). Since 2011, gasoline demand growth has been primarily in PADD 3, followed by PADD 1c, a subsection of PADD 1 that covers the lower Eastern seaboard, from West Virginia to Florida.

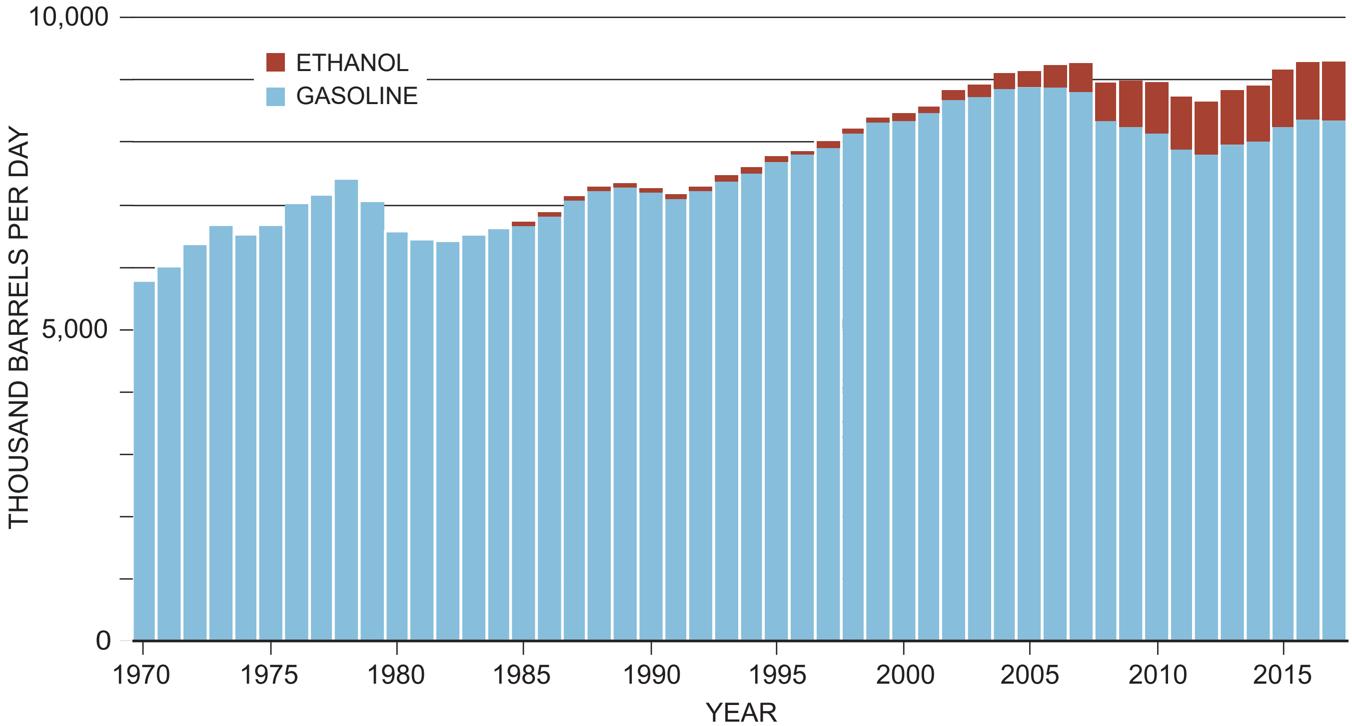
There are strong logistical linkages between the PADDs for efficient movements of gasoline from their producing regions to consumption regions. The majority of these movements in the United States take place via pipelines. Note that ethanol is blended at fuel distribution terminals, commonly called “racks,” and therefore uses alternative transportation means, typically by rail or truck, to reach its final destination. Only gasoline produced from crude oil sources is moved by the current U.S. refined product pipeline system. Figure 1-33 shows major refined product pipeline systems in the United States that help facilitate the movements between regions. These pipelines are relevant for gasoline, diesel, and jet fuel movements in the country.

Figure 1-34 shows the relationship between sources of gasoline by PADD compared to uses by PADD. In 2017, PADD 1 produced 598,000 B/D of gasoline from local refineries, received 1.8 MMB/D of gasoline from other PADDs (primarily PADD 3), imported another 552,000 B/D of gasoline, and blended 334,000 B/D of ethanol to meet the



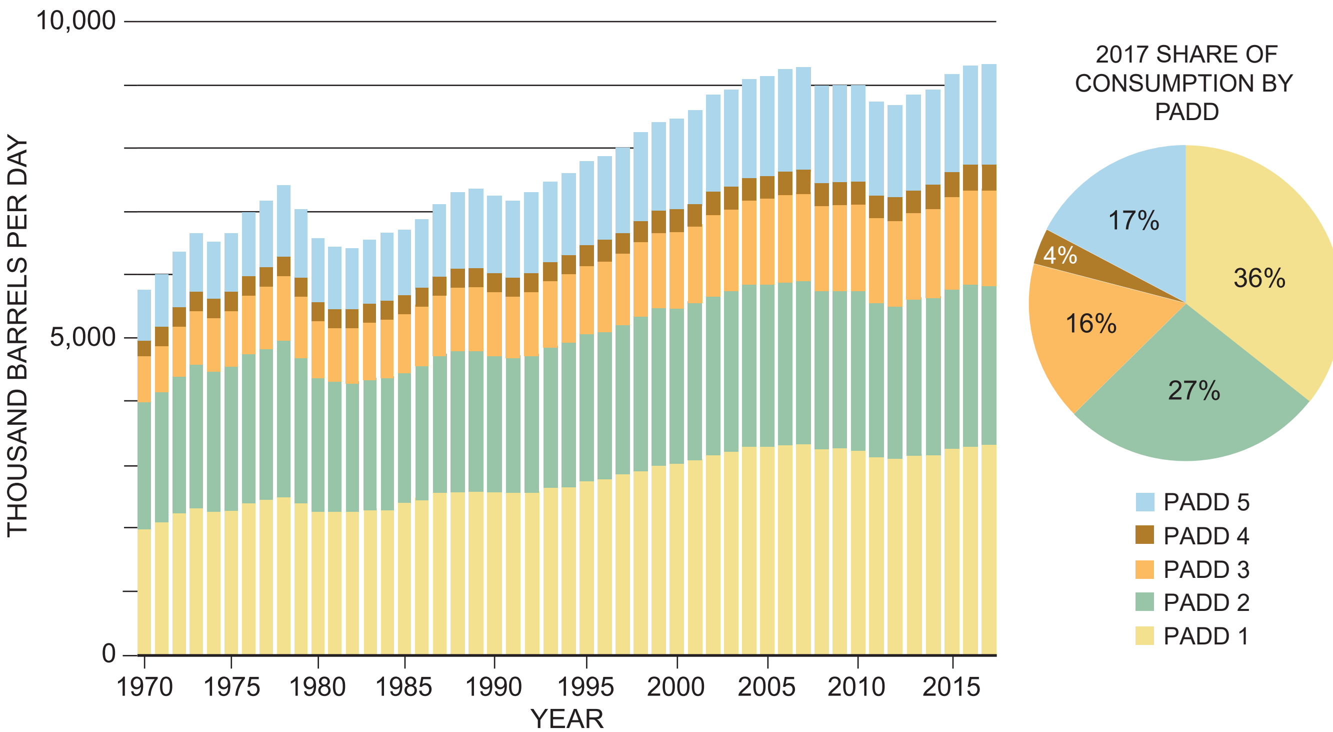
Source: EIA, Maps, Oil and Gas.

Figure 1-30. *Census Region Map with PADD Boundary Overlay*



Source: EIA, Petroleum & Other Liquids, Product Supplied by Product.

Figure 1-31. *U.S. Gasoline Consumption*

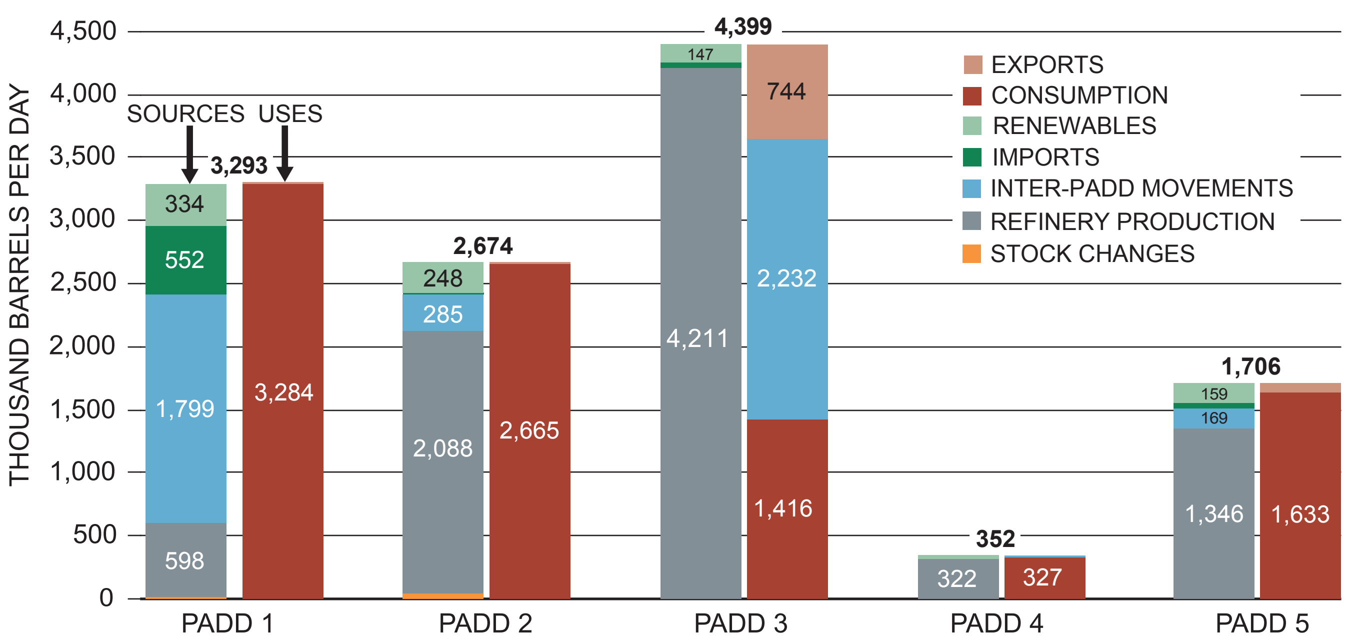


Source: EIA, Petroleum & Other Liquids, Product Supplied by Area.

Figure 1-32. *Historical Gasoline Consumption by PADD*
(includes ethanol blended into gasoline)

Source: Airlines for America.

Figure 1-33. *Major U.S. Products Pipelines Carrying Jet Fuel*



Note: Gasoline includes finished gasoline and blending components. Stock change is calculated to balance sources and uses.
"Product Supplied" is assumed to be "Consumption."
Source: EIA Petroleum & Other Liquids data and Baker & O'Brien Analysis.

Figure 1-34. *Sources and Uses of Gasoline in the United States in 2017*

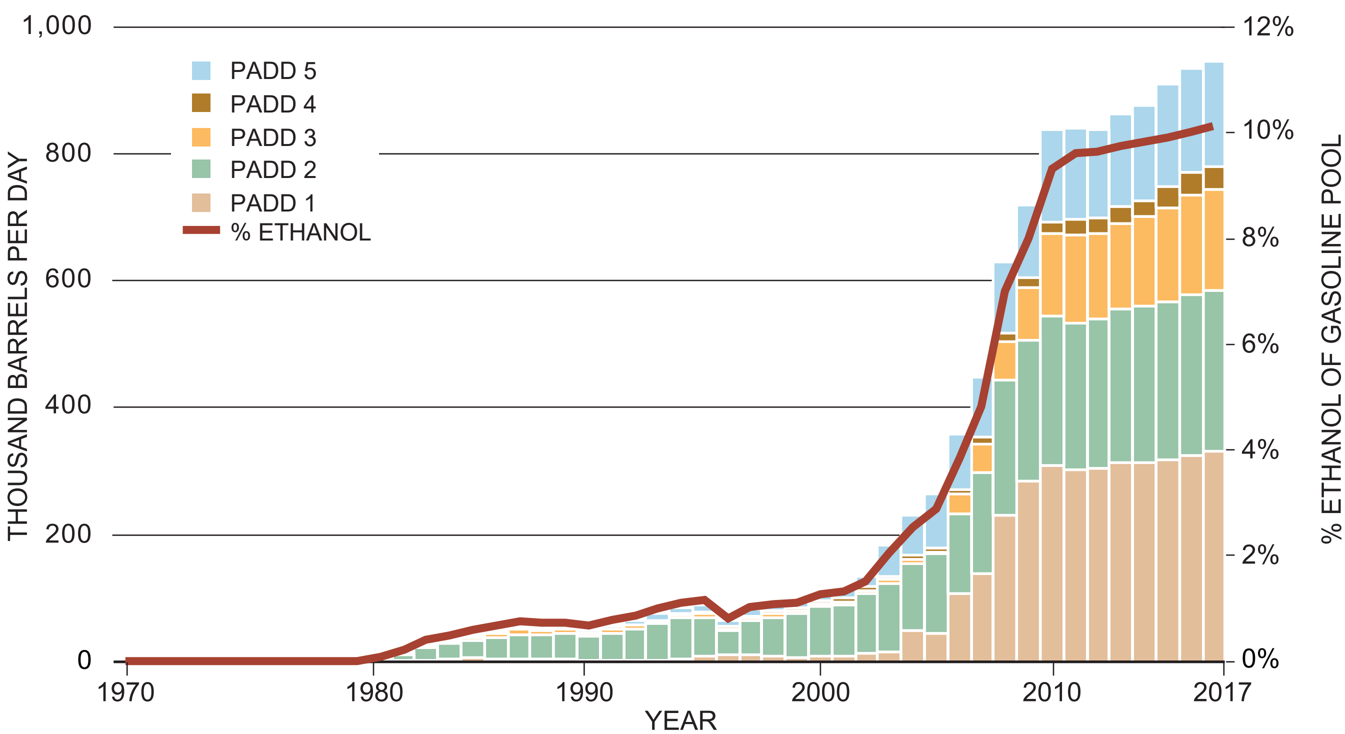
3.3 MMB/D finished gasoline demand. In contrast, PADD 3 produced 4.2 MMB/D of gasoline blendstocks, blended 147,000 B/D of ethanol, and imported a small amount. However, PADD 3 only consumed 1.4 MMB/D while shipping 2.2 MMB/D to other PADDs and exporting 744,000 B/D. This dynamic as it relates to projections of gasoline consumption in 2040 will be discussed later in this section.

Renewable fuels, such as ethanol, biodiesel, and renewable diesel have become increasingly important components of the transportation fuel mix through mandates required under the Renewable Fuel Standard and incentives provided by Low Carbon Fuel Standard (LCFS) programs.

Ethanol consumption grew at a staggering pace between 2005 and 2009, driven by the elimination of MTBE and passage of the Renewable Fuel Standard, eventually comprising approximately 10% of the gasoline pool (Figure 1-35). However, while the overall quantity of production has grown since 2009, the percentage of the gasoline pool has not increased appreciably over 10%.

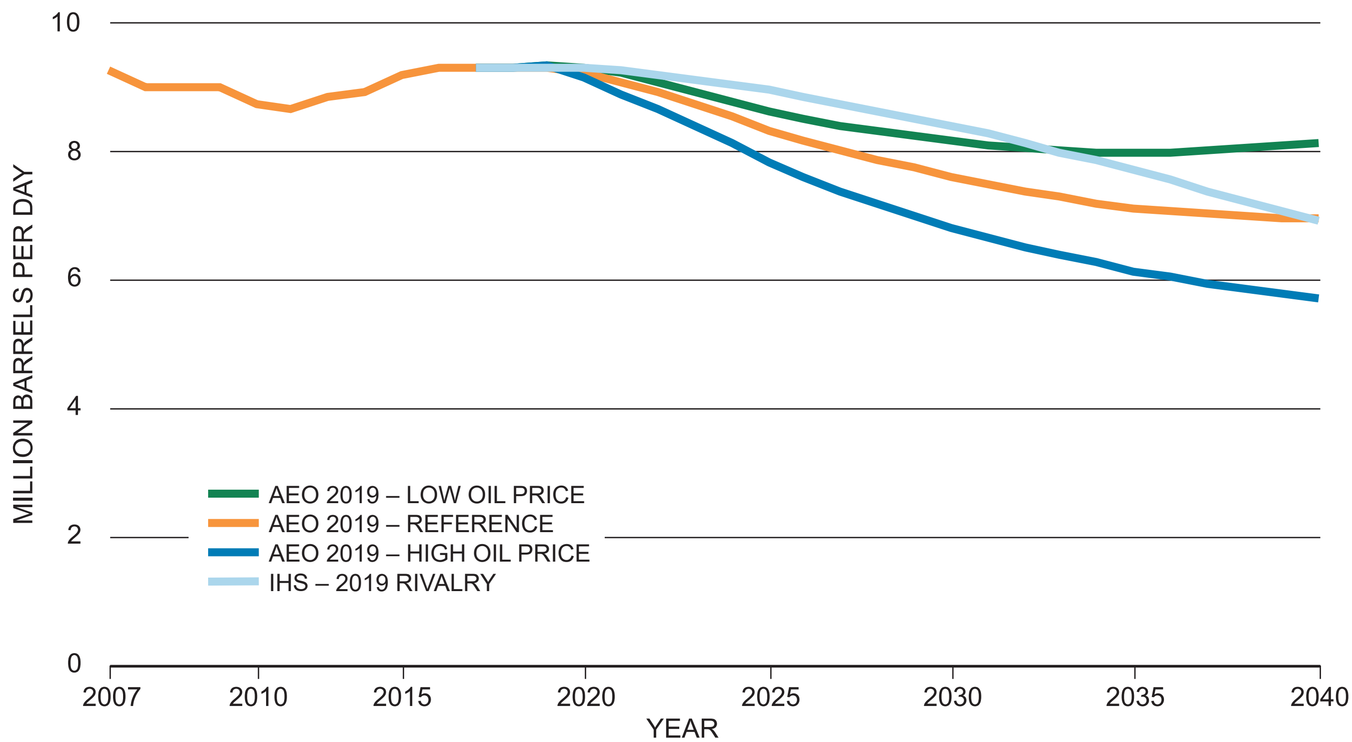
The EIA's AEO 2019 and IHS Markit's 2019 Rivalry scenarios were utilized to analyze a gasoline consumption outlook (Figure 1-36). Detailed information was not available by refined product stream from the other projections. None of the scenarios reviewed in this analysis include a projection of increasing consumption of gasoline in the United States. These projections note that due to increasing transportation sector fuel economy and increasing penetration of alternative fuel vehicles, overall fleet efficiency improves.

The only outlook provider with detailed information at the regional level was the EIA's AEO 2019. The decline in gasoline consumption in EIA's AEO 2019 projection is seen in all regions around the country. For consumption projections, the EIA uses census regions rather than PADDs. Table 1-2 shows Baker & O'Brien's estimate of refinery gasoline production by census region, compared to the EIA's AEO 2019 Reference Case projection of gasoline consumption in 2017 and 2040. Census region gasoline net balance, refinery production minus net gasoline consumption (gasoline consumption minus ethanol), is calculated.



Source: EIA, Petroleum & Other Liquids data.

Figure 1-35. U.S. Ethanol Consumption



Source: EIA, *Annual Energy Outlook 2019*, and IHS Markit.

Figure 1-36. *Gasoline Demand Forecasts*

Million Barrels per Day	Refinery Production Baker & O'Brien Est.	Consumption EIA AEO 2019 Ref.		Net Consumption Assumes 10% Ethanol		Net Balance	
Census Region	**2017**	**2017**	**2040**	**2017**	**2040**	**2017**	**2040**
New England	0.00	0.42	0.31	0.38	0.28	(0.38)	(0.28)
Middle Atlantic	0.60	0.96	0.67	0.86	0.60	(0.26)	(0.00)
East North Central	1.10	1.34	0.98	1.21	0.88	(0.11)	0.22
West North Central	0.44	0.71	0.55	0.64	0.50	(0.20)	(0.06)
South Atlantic	0.00	1.92	1.51	1.73	1.36	(1.73)	(1.36)
East South Central	0.32	0.66	0.47	0.59	0.42	(0.27)	(0.10)
West South Central	4.30	1.30	1.06	1.17	0.95	3.13	3.35
Mountain	0.39	0.67	0.60	0.60	0.54	(0.21)	(0.15)
Pacific	1.30	1.33	0.81	1.20	0.73	0.10	0.57
Totals	**8.45**	**9.31**	**6.96**	**8.38**	**6.26**	**0.07**	**2.19**

Source: EIA, *Annual Energy Outlook 2019*, and Baker & O'Brien.

Table 1-2. *Regional Gasoline Supply and Demand Balances*

Assuming refinery capacity, utilization, and production capabilities do not change, the projected reduction in gasoline consumption will impact the flows and placement of gasoline and/or gasoline component barrels around the country. It is not possible to name the most likely scenario in certain regions due to the interplay of refining, pipeline, and export economics. Notably in Table 1-2, the East North Central Region (highlighted) moves from a situation where the region is slightly short on gasoline production (regional consumption is slightly higher than refinery production) to long on gasoline production, requiring product to find a demand center outside the region. Similarly, the Mid-Atlantic and West North Central regions could move into a balanced situation. Overall, with gasoline consumption projected to decline, exports may increase and/or refinery utilization and yields may shift.

Finding: U.S. liquids consumption (refined products and biofuels) is projected to decline between 2017 and 2040 under most scenarios.

Demand reduction is most prominent in the gasoline market.

The infrastructure implications could include increased export capabilities, particularly along the U.S. Gulf Coast and potentially the U.S. West Coast. In addition, certain areas where product used to flow by pipeline or barge into the region could see those movements reduced or reversed.

b. Distillate

Distillate consumption includes diesel and heating oil used for on-road transportation fuels, home heating oil, and some smaller industrial and commercial sector uses. Distillate consumption in the United States has grown between 1970 and 2017; however, there have been periods of decline in consumption such as the early 1980s and after the major recession in 2008. As of 2017, PADDs 1 and 2 both accounted for 30% of U.S. distillate consumption (Figure 1-37).

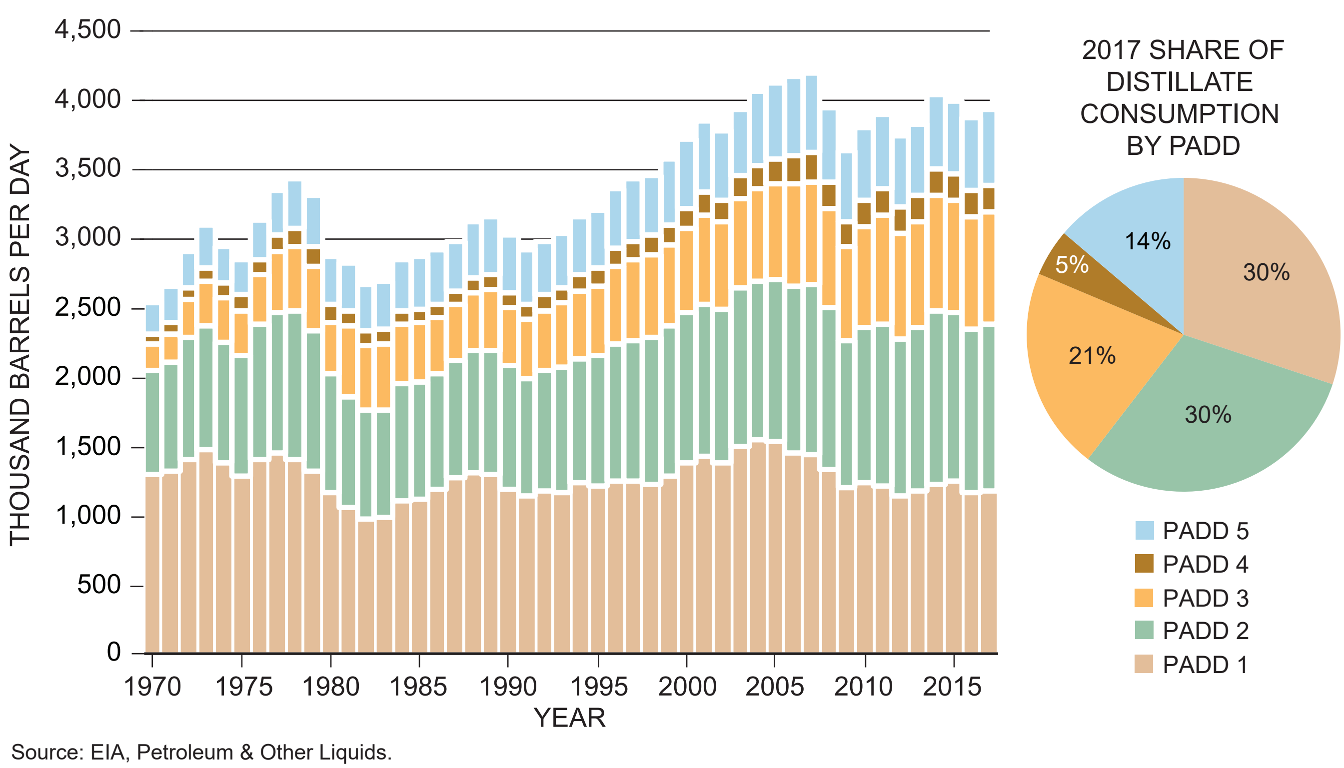
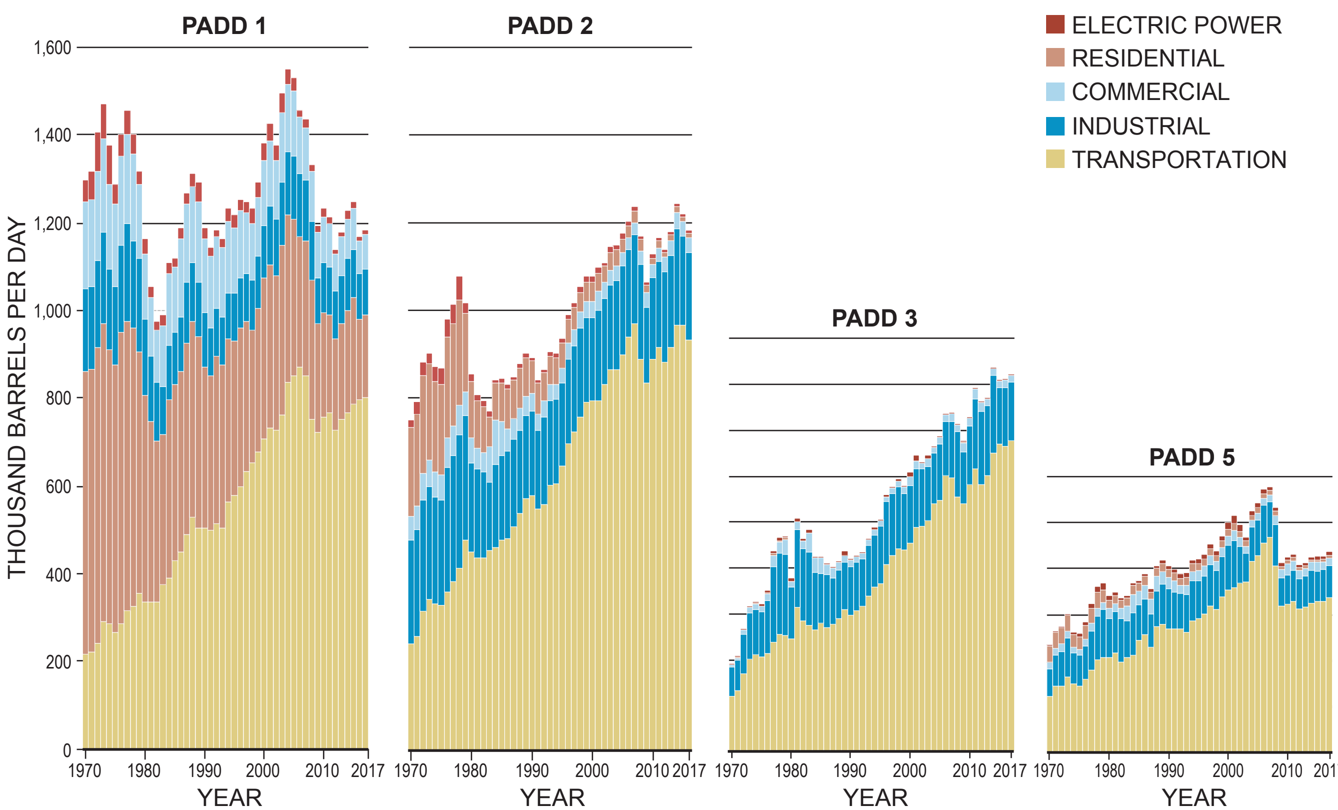


Figure 1-37. *Historical Distillate Consumption by PADD*

Given the varying uses for distillate, segregating consumption by sector provides some interesting insights. Figure 1-38 shows distillate use by sector across the four largest PADDs. PADD 4 shows a similar trend to the other four but is not shown for ease of presentation. Distillate use in the form of diesel for transportation use has grown across all PADDs since 1970 (transportation). However, the overall growth trend has not been as robust due to the reduction in heating oil usage in PADDs 1 and 2 (residential). This reduction in heating oil demand has largely been due to conversions of home heating fuel sources to other cheaper and cleaner alternatives, such as natural gas. Recently, oil-to-natural gas conversions in certain regions, such as the Northeast, have been limited due to natural gas pipeline constraint issues.

The pipeline and waterborne infrastructure that connects the PADDs is important to the distillate market to bridge the gap between production and consumption in regions. Figure 1-39 shows sources and uses of distillate by PADD in 2017. For example, PADD 1 produced 324,000 B/D of diesel at local refineries, received 743,000 B/D from other PADDs (primarily PADD 3), and imported the remainder to meet its 2017 consumption requirements. In contrast, PADD 3 produced 2.8 MMB/D while only requiring 787,000 B/D for consumption. The remainder was shipped to other PADDs or exported to international locations.

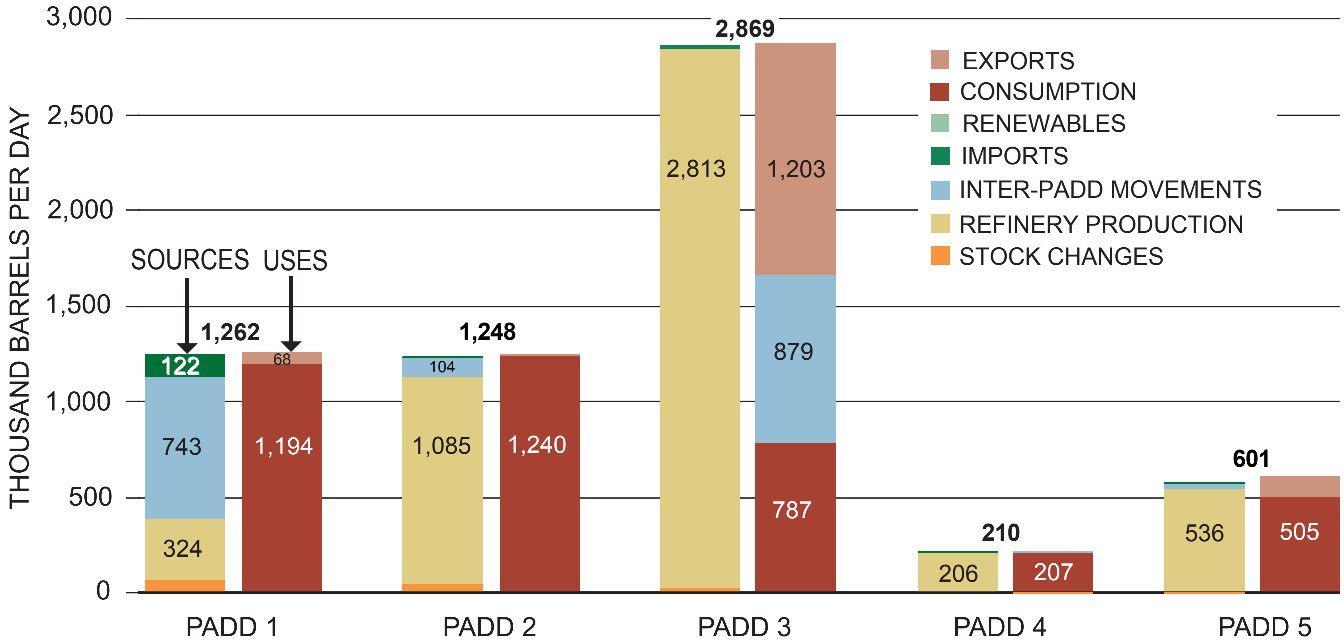
Similar to ethanol blending, biodiesel and renewable diesel blending has increased over the last few years (Figure 1-40). According to the EIA, biodiesel and renewable diesel combined represented approximately 4% of the distillate consumed in the United States in 2017. Production of biodiesel and renewable diesel is currently incentivized by U.S. policy as they qualify for two major renewable fuel programs in the United States: the nationwide Renewable Fuel Standard and California's LCFS. Consumption of biodiesel and renewable diesel is encouraged via tax credits. Most recently, the



Note: PADD 4 is not shown due to low consumption levels.

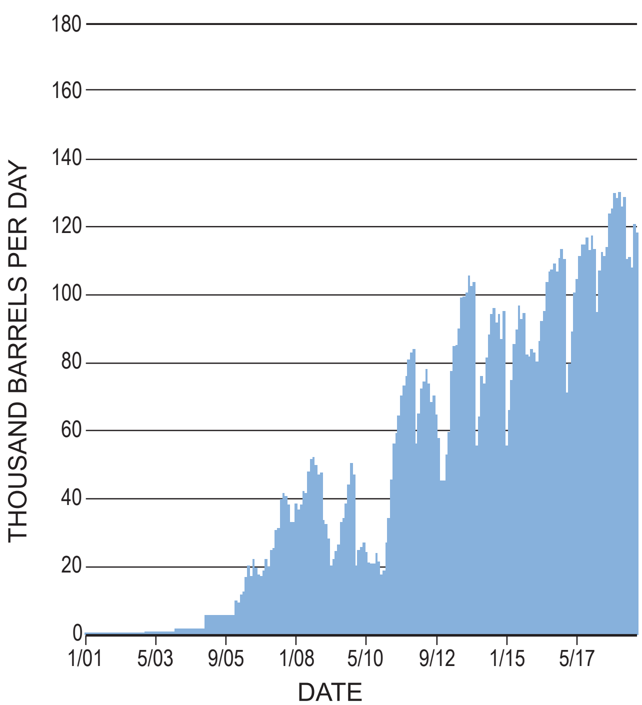
Source: EIA, Petroleum & Other Liquids, Sales of Distillate Fuel Oil by End Use, by Area.

Figure 1-38. *Diesel Demand by Sector*



Note: Stock change is calculated to balance sources and uses. "Product Supplied" is assumed to be "Consumption."
Source: EIA, Petroleum & Other Liquids data, and Baker & O'Brien Analysis.

Figure 1-39. *Sources and Uses of Distillate in 2017*



Source: EIA, *Monthly Energy Review*, August 2019, Renewable Fuels Overview.

Figure 1-40. *U.S. Biodiesel Production*

proposed Biodiesel Tax Credit Extension Act would restore a $1.01 per gallon biofuel producer credit and a $1 per gallon tax credit for biodiesel that expired at the end of 2017.

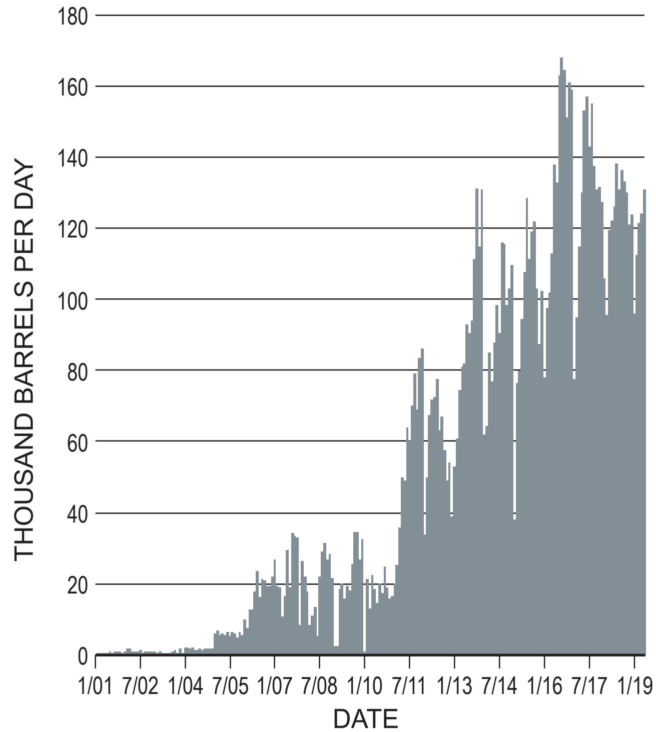
Both biodiesel and renewable diesel fuels are alternative fuels produced from refining vegetable oils or animal fats. Biodiesel is blended with petroleum diesel up to 5% or 20% by volume (referred to as B5 and B20, respectively). Renewable diesel is a drop-in fuel—meaning that it meets specifications for use in existing infrastructure and diesel engines—and is not subject to any blending limitations. Renewable diesel is chemically similar to petroleum diesel and is nearly identical in its performance characteristics.

Biomass-based diesel fuels have additional advantages over other renewable fuels, such as ethanol used in gasoline blending, because of their relatively high energy content and low-carbon intensity, which allow them to qualify for higher credit values in both renewable fuel programs.

The market for renewable diesel (Figure 1-41) has grown significantly in recent years, particularly in California. The fuel surpassed ethanol as the largest generator of LCFS credits in the first two-quarters of 2019, indicating that the pull toward renewable diesel will remain strong.

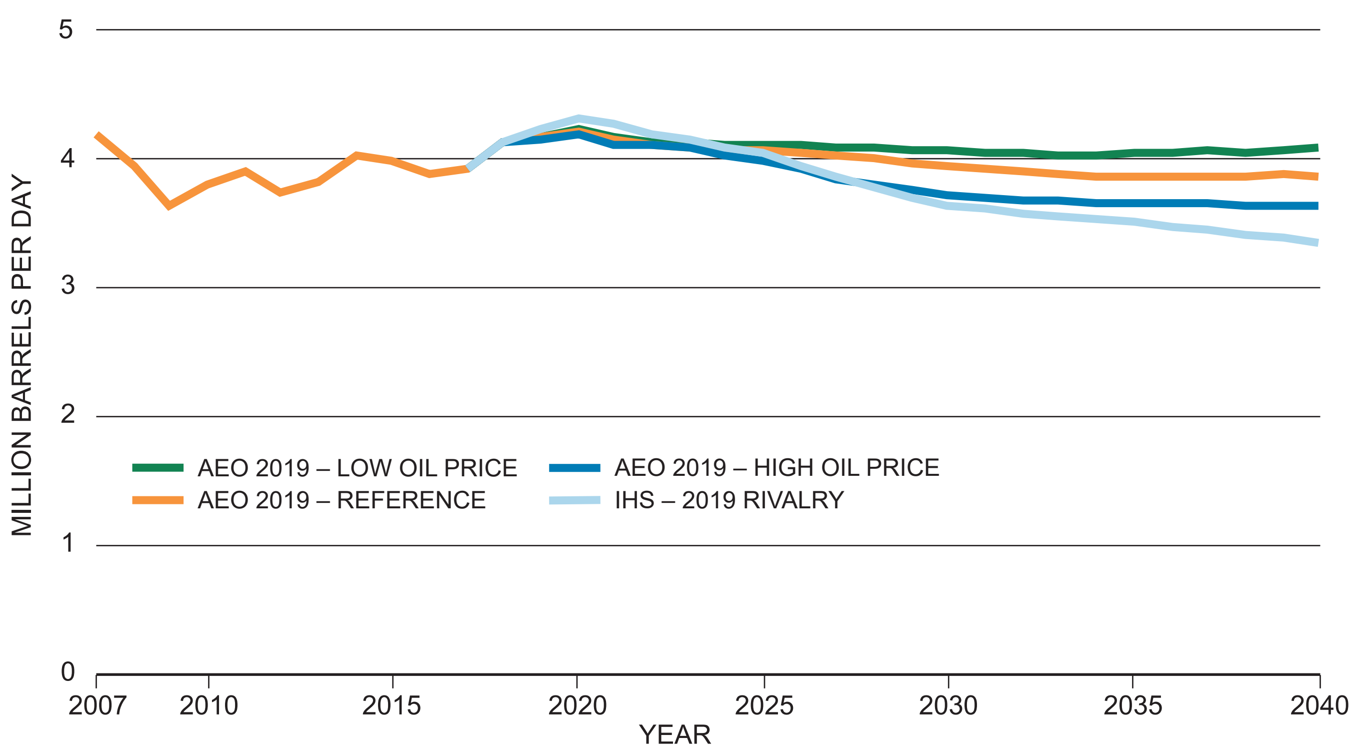
The EIA's AEO 2019 and IHS Markit's 2019 Rivalry scenarios were utilized to analyze the distillate consumption outlook. Detailed information was not available by refined product stream from the other projections. Figure 1-42 compares the Reference case, Low Oil Price case and High Oil Price case, as well as IHS Markit's 2019 Rivalry Scenario. The Reference case projects a slight reduction in consumption through 2040, while the Low Oil Price case would maintain similar consumption levels to those seen in 2018.

The EIA's AEO 2019 was utilized to analyze the distillate consumption outlook by region due to lack of detailed information provided from other projections by refined product stream regionally.



Source: EIA, *Monthly Energy Review*, August 2019, Renewable Fuels Overview.

Figure 1-41. *Historical Biodiesel Consumption*



Source: EIA *Annual Energy Outlook 2019* and IHS Markit.

Figure 1-42. *U.S. Distillate Demand Forecast (Outlooks include biodiesel and renewable diesel blended.)*

Table 1-3 shows the EIA's AEO 2019 Reference Case projection of distillate consumption, including biodiesel blended, by region, from 2017 to 2040. The New England and Mid-Atlantic regions are projected to experience the largest declines in consumption. However, other regions such as the West South Central, Mountain, and Pacific are projected to have a slight increase in consumption by 2040.

Given that the EIA does not project distillate consumption to be considerably different in 2040 compared to 2017, impacts to infrastructure will be limited if viewed in isolation to the impacts from gasoline declines. Regions that were already oversupplied in 2017 by refiners, such as the East North Central, West South Atlantic, and Pacific, continue to be oversupplied in 2040 in the EIA's scenario. No regions are projected to flip from short diesel to being long diesel, such as what was seen in the gasoline scenario. Without dramatic swings in consumption, refinery production, or biodiesel and renewable diesel blending, diesel imports and exports would appear to stay stable through 2040.

c. *Jet Fuel*

Jet fuel consumption is driven by use in the commercial airline and military sectors. Figure 1-43 shows historical consumption for jet fuel in the United States. Historical consumption has been impacted by external influences such as reach of network, advent of low-cost carriers, military action, economic conditions, oil price, and events such as Severe Acute Respiratory Syndrome (SARS) outbreak or September 11, 2001. The figure shows consumption by PADD as well as some of these drivers of demand, broken into two categories: (1) "Desire to Fly" and (2) economic/oil price.

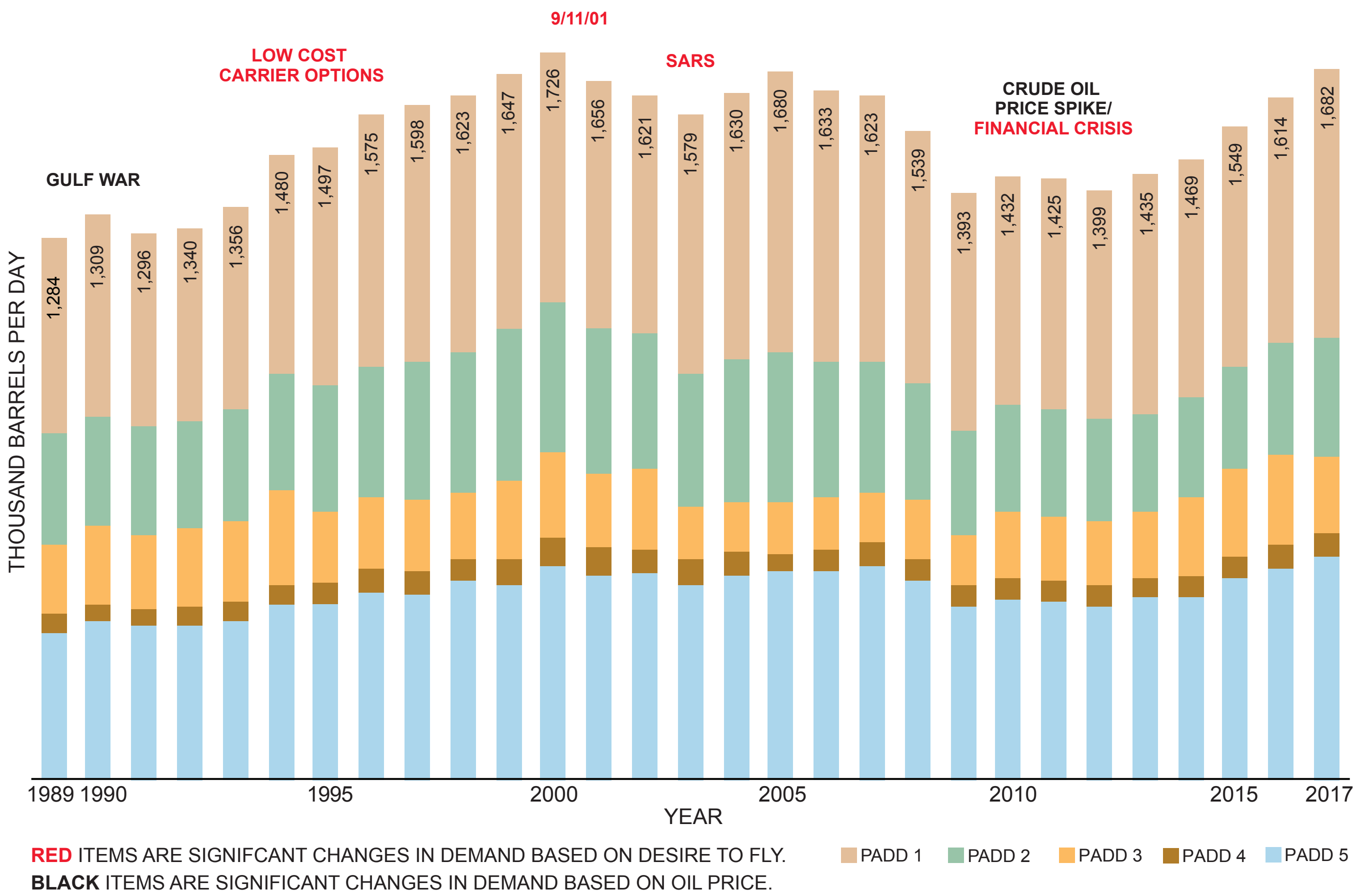
Jet fuel supply utilizes multiple modes of transport, including pipelines, trucks, marine vessels, and rail. Due to the historical lack of investment in jet fuel infrastructure, the continued growth in demand is giving rise to certain airport specific issues, such as lack of pipeline capacity to key airports (e.g., San Francisco [SFO]) and significant increases in trucking (e.g., Austin, Texas [AUS]).

Another associated issue is the lack of investment in additional jet fuel storage capacity at many major airports. Increased demand reduces the inventory on-hand to a matter of days, so these airports are reliant on continued operation of (in many cases) a single pipeline supply. Any service interruption on that pipeline would have a serious impact on airline operations in a very short time.

Million Barrels per Day	Refinery Production Baker & O'Brien Est.	Consumption EIA AEO 2019 Ref.		Net Consumption Assumes 4% Bio/Renewable		Net Balance	
Census Region	**2017**	**2017**	**2040**	**2017**	**2040**	**2017**	**2040**
New England	0.00	0.19	0.14	0.18	0.13	(0.18)	(0.13)
Middle Atlantic	0.32	0.42	0.36	0.40	0.35	(0.08)	(0.03)
East North Central	0.55	0.54	0.51	0.52	0.49	0.03	0.06
West North Central	0.28	0.41	0.41	0.39	0.39	(0.11)	(0.11)
South Atlantic	0.00	0.59	0.59	0.57	0.57	(0.57)	(0.57)
East South Central	0.18	0.29	0.29	0.28	0.28	(0.10)	(0.10)
West South Central	2.80	0.72	0.75	0.69	0.72	2.11	2.08
Mountain	0.26	0.33	0.36	0.32	0.35	(0.06)	(0.09)
Pacific	0.60	0.43	0.47	0.41	0.45	0.19	0.15
Totals	**4.99**	**3.92**	**3.88**	**3.76**	**3.72**	**1.23**	**1.27**

Source: EIA, *Annual Energy Outlook 2019,* and Baker & O'Brien.

Table 1-3. *Regional Distillate Supply and Demand Balances*



Source: EIA, Petroleum & Other Liquids.

Figure 1-43. *U.S. Product Supplied of Kerosene-Type Jet Fuel*

The EIA AEO 2019 Reference Case and Federal Aviation Administration (FAA) projections were utilized to analyze potential consumption outlooks. While jet fuel is one of the smallest categories of transportation fuels, it has one of the most aggressive growth profiles of all the petroleum products at greater than 2% per year in the United States, and as much as 4% per year globally. In reality, volatility in demand can be considerable in just a single year, and even more so at an individual airport. For example, the demand at San Francisco Airport grew more than 12% from 2017 to 2018 almost entirely due to the introduction of the ultra-large Airbus 380 aircraft.

Figure 1-44 shows the EIA demand forecast through 2040 compared to the FAA's passenger growth forecast, which has a similar trajectory. The FAA uses available seat miles which accounts for aircraft size and distance flown, thus having a very high correlation (~99%) to fuel consumption. What the FAA's forecast would not capture is improvements in aircraft fuel efficiency. This is likely the difference between the FAA and EIA forecasts.

Each generation of aircraft has a good record of being considerably more fuel efficient than the previous generation. The improvement can be greater than 30% in a single decade. At issue, however, is that airlines keep airplanes in their fleet for an average of 25 to 30 years (these happen to be the depreciable lives of Boeing and Airbus aircraft). Thus, if it takes 30 years to turn over an entire fleet to the more efficient planes, the realized efficiency gain is closer to 1% per year.

One important variable that may not be considered enough in the consumption forecasts available is next generation aircraft that fly at considerably higher speeds (i.e., supersonic). These aircraft could consume substantially more jet fuel than current fleets.

The analysis shown in Figure 1-45 that aircraft (and engine) technology will mitigate but not solve the growth in demand and the associated stress on jet fuel's supply infrastructure.

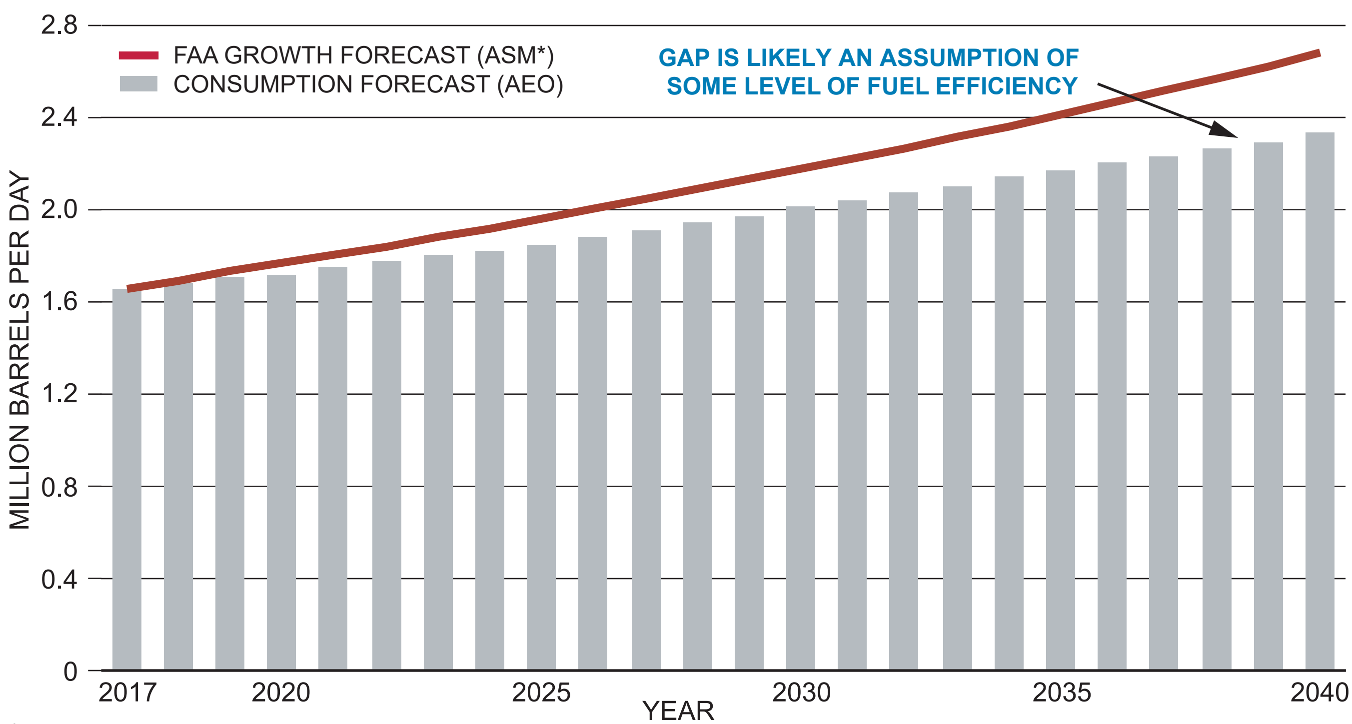
Some of the projected growth in demand will be supplied by nonfossil based renewable jet fuel, termed sustainable aviation jet fuel. This industry is in its infancy, with total global current production less than four million gallons per year according to the Commercial Aviation Alternative Fuels Initiative. A separate topic paper on biojet has been included in this report. Use of renewables by airlines will be further stimulated by the regulations being promulgated by the UN's International Civil Aviation Organization, under the title Carbon Offsetting and Reduction Scheme for International Aviation. This requires airlines to achieve carbon neutral growth by 2020. Furthermore, airlines have agreed to collectively cut net CO_2 emissions by 50% by 2050 compared to 2005 levels.

Predictions of the future amounts of renewable jet fuel being consumed is extremely difficult. Broad range indications vary anywhere between 2% by 2025 to 30% by 2030. Considerable investments would be needed to get to these levels.

d. Residual Fuel Oil

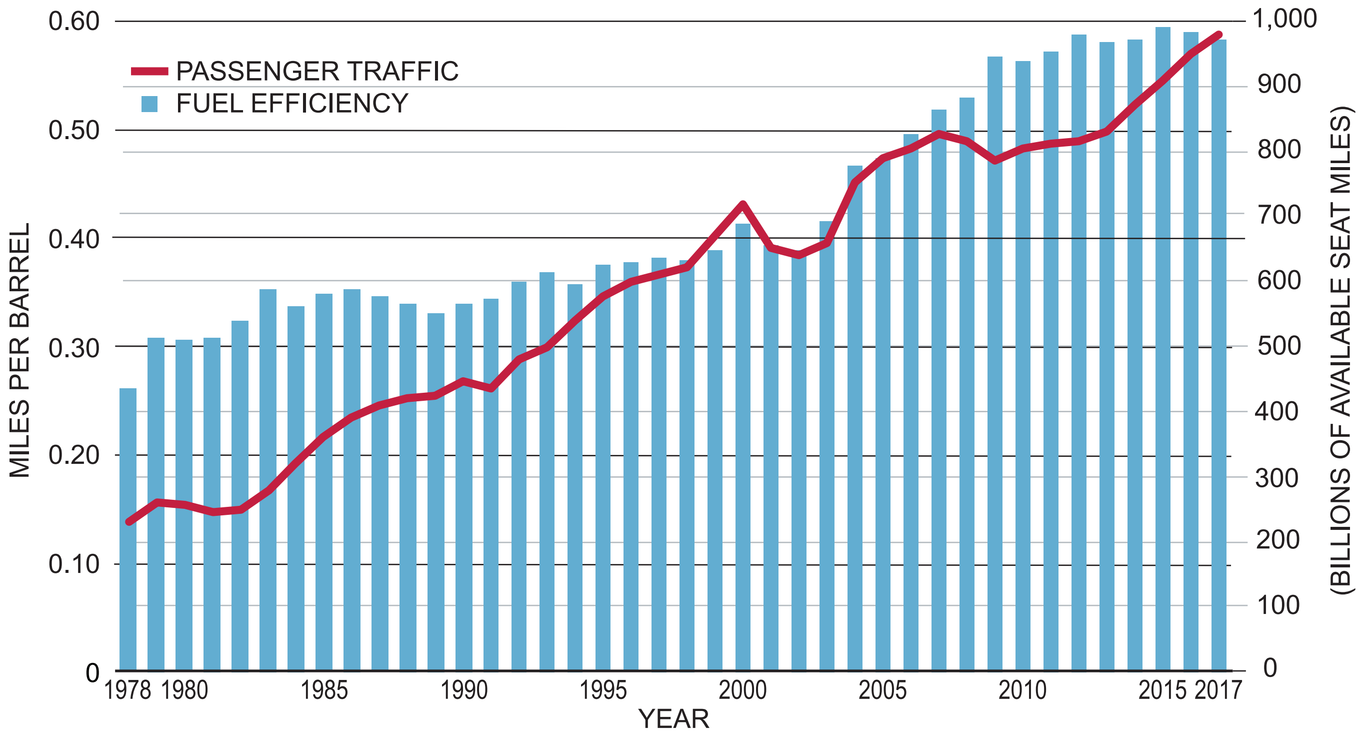
Residual fuel oil is a byproduct produced by a refinery that is left over from the crude oil after the rest has been converted to finished products. Residual oil fuel consumption has declined dramatically in the United States since the 1970s (Figure 1-46). Correspondingly, most refineries have invested in secondary conversion units, such as cokers, to upgrade this stream into higher-value finished products such as gasoline and diesel.

The reduction in residual fuel oil consumption has primarily been driven by a reduction of use in the electric power industry and the industrial



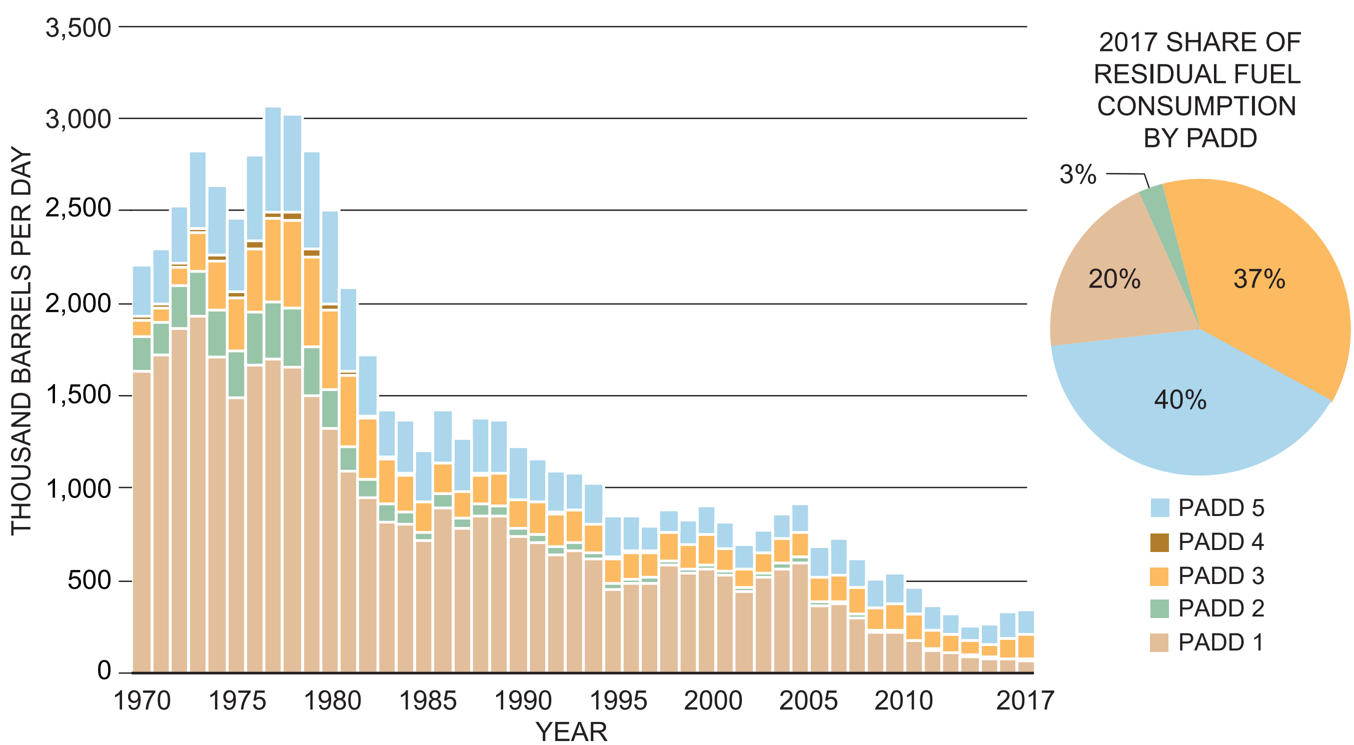
* Available seat miles.
Source: EIA *Annual Energy Outlook 2018,* and Federal Aviation Administration.

Figure 1-44. *Jet Fuel Demand Forecast*



Source: EIA *Annual Energy Outlook 2018*, and Federal Aviation Administration.

Figure 1-45. *Jet Fuel Efficiency Does Not Keep Up with Demand*



Source: EIA, Petroleum & Other Liquids.

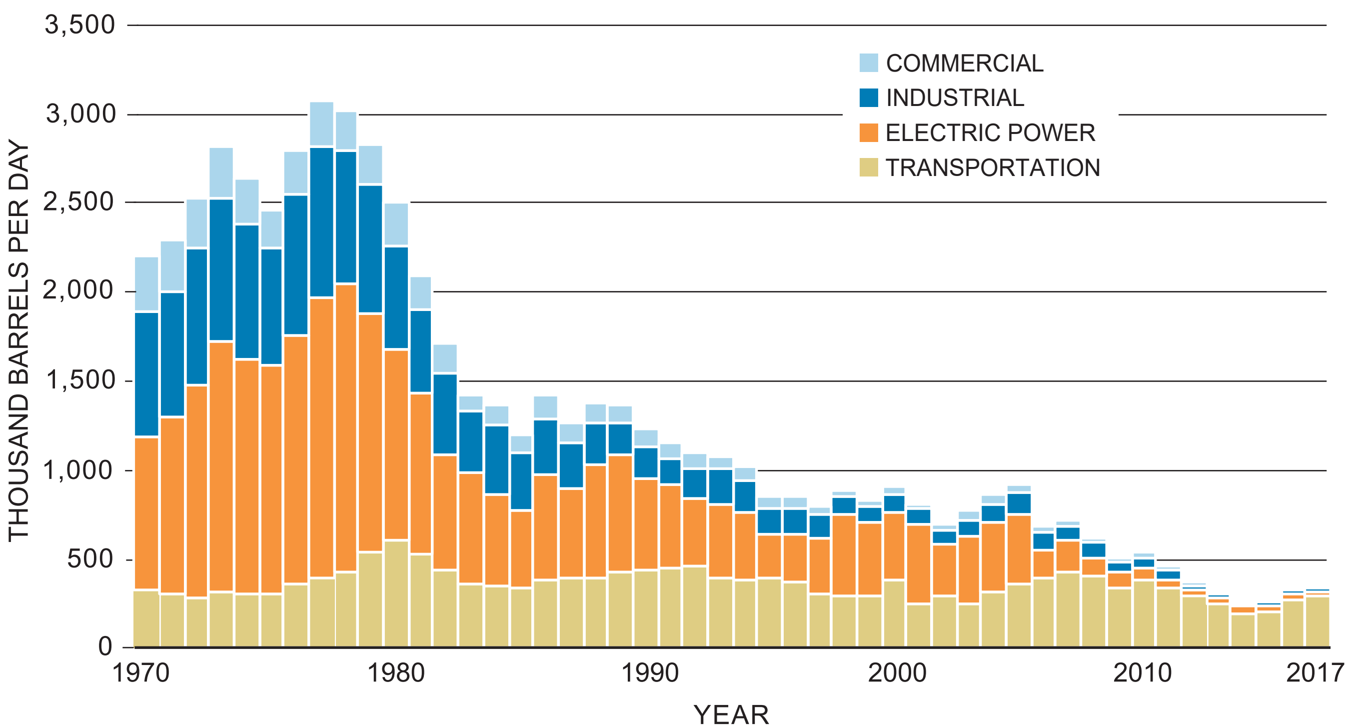
Figure 1-46. *U.S. Residual Fuel Oil Consumption by PADD* sector, as these sectors have moved to cleaner and more cost-effective fuels such as natural gas (Figure 1-47). The remaining markets for RFO-type material are primarily asphalt (road paving and roofing) and bunkers (ship fuel). The shipping sector consumption of residual fuel oil has remained relatively stable; however, this sector will potentially see a dramatic change in fuels in 2020 with the start of new sulfur content rules imposed by International Maritime Organization (IMO) 2020; IMO is a specialized agency of the United Nations.

Effective January 1, 2020, marine vessel fuel oil (bunker fuel) will not be allowed to exceed 0.5% sulfur. The specification is currently 3.5%, so it is home to a large part of the residual fuel oil blendstock from refining. After the regulation is in force, the majority of this product will have to find a new end use or be upgraded to meet the new specifications.

IMO regulations to reduce sulfur oxides (SOx) emissions from ships first came into force in 2005, under Annex VI of the International Convention for the Prevention of Pollution from Ships (known as the MARPOL Convention). Since then, the limits on sulfur oxides have been progressively tightened. IMO 2020 refers to a further reduction in the sulfur specifications, but with a significant step-change down from 3.5% to 0.5%. Ship owners have until January 1, 2020, to decide on how they are going to be compliant with the international standard. Options for compliance include purchasing ultra-low sulfur fuel oil, investing in scrubber technology, or utilizing alternative fuels such as LNG.

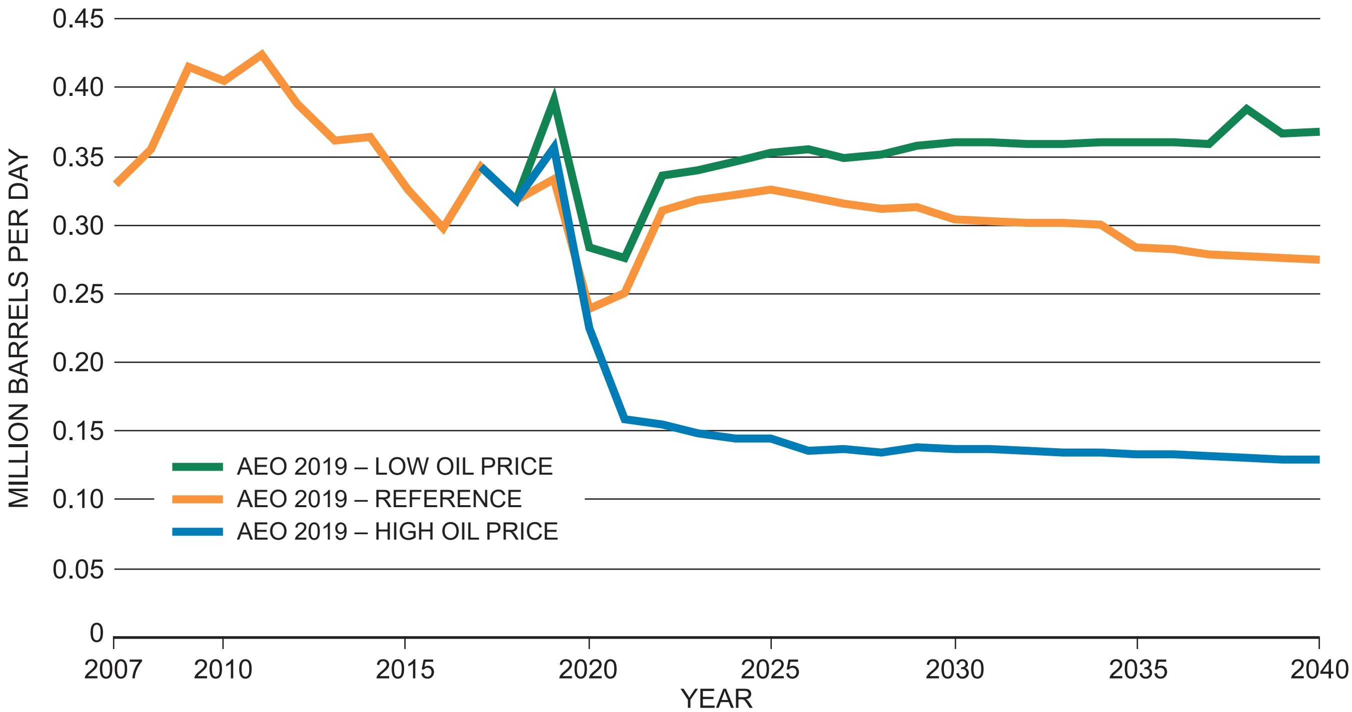
Figure 1-48 shows a comparison of the Reference case, Low Oil Price case, and High Oil Price case from the EIA's AEO 2019. The Reference case projects a slight reduction in consumption through 2040, while the Low Oil Price case would maintain similar consumption levels to those seen in 2018 and the High Oil Price case would result in a drastic reduction.

The EIA's AEO 2019 Reference Case was utilized to analyze the residual fuel oil consumption



Source: EIA, Petroleum & Other Liquids.

Figure 1-47. *U.S. Residual Fuel Oil Consumption by Sector*



Source: EIA, *Annual Energy Outlook 2019*, Projection Tables for Side Cases: Petroleum & Other Liquids Supply and Disposition.

Figure 1-48. *Residual Fuel Oil Consumption Projections*

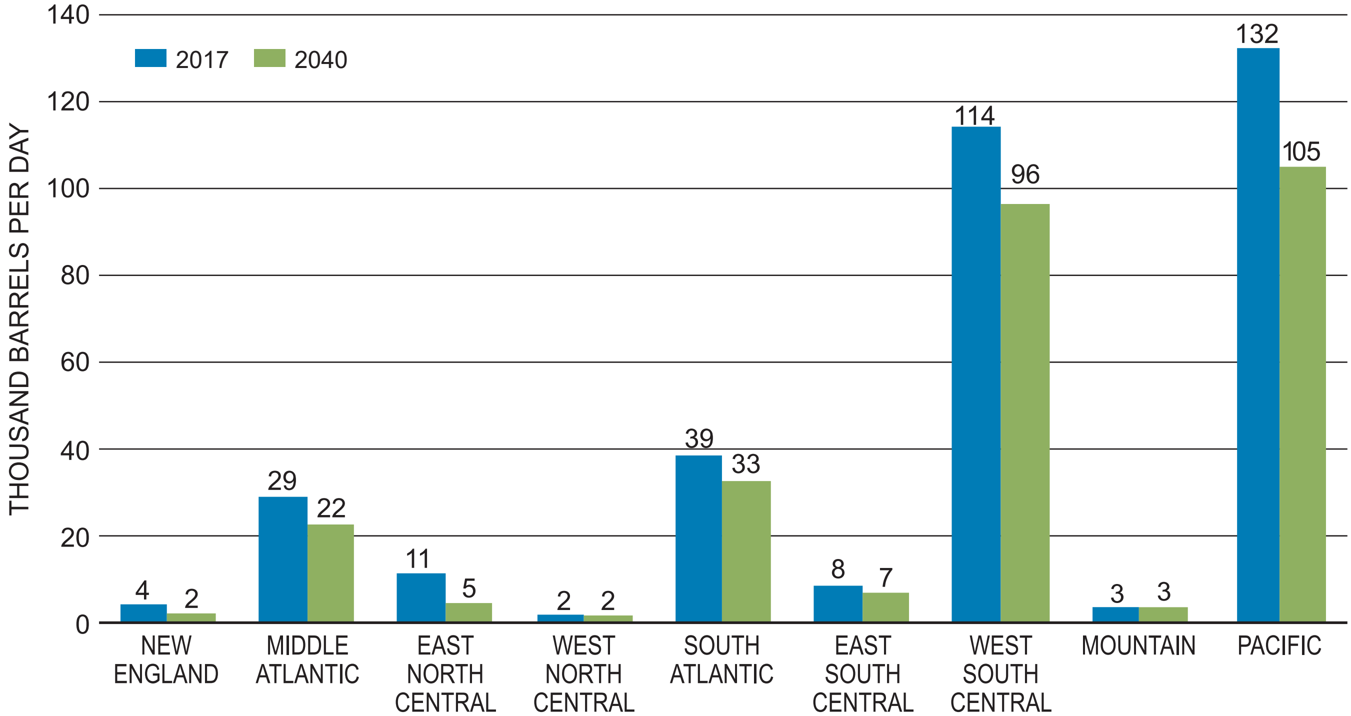
outlook by region due to lack of detailed information provided from other projections by refined product stream. Figure 1-49 shows the EIA's AEO 2019 Reference Case projection of residual fuel oil consumption, including by region. Given that the primary sector for consumption of residual fuel oil is in the shipping industry, the largest changes in consumption are seen in the coastal regions along the East Coast (Mid-Atlantic, South Atlantic), Gulf Coast (West South Central), and West Coast (Pacific).

The EIA's Reference Case projects decreasing consumption of residual fuel oil in all PADDs in the United States. Residual fuel oil is not carried by interstate pipelines, but rather by rail, truck, and barge. Therefore, the reduction in consumption will need to be met through altered refinery configuration or exports along the coast.

E. Natural Gas

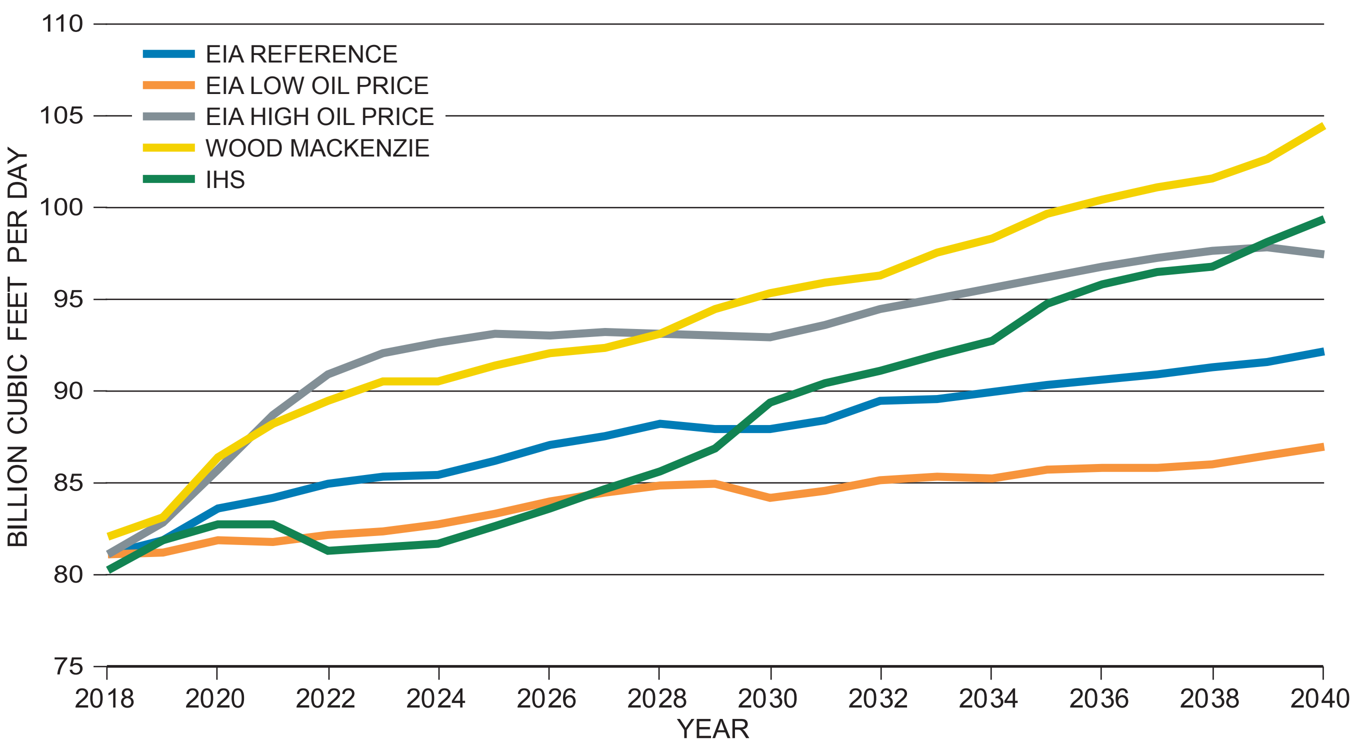
Whereas the demand forecast for refined products is flat to declining through 2040, natural gas demand is projected to significantly increase over the period as abundant, inexpensive supplies due to shale extraction techniques contribute to the transition from coal. Figure 1-50 shows demand growth from a subset of the forecasts. This is driven, in part, by demand for natural gas in the electric power sector. Natural gas-fired generators can quickly ramp up, allowing natural gas to complement intermittent energy sources such as wind and solar and ensure electricity demand is met, when renewable energy sources are not available. This is exemplified in California, which has a high usage of solar and wind generation. Natural gas plays an important role in meeting the state's electric power demand, including during early morning and evening hours when solar resources are not available. It should be noted that battery installations to store energy produced from these renewable sources are increasingly being incorporated as the primary backup, which will dampen the natural gas demand growth over time.

In contrast to liquids consumption, all outlooks reviewed for U.S. natural gas demand shown in Figure 1-50, show strong growth. The most



Source: EIA, *Annual Energy Outlook 2019*, AEO 2019 Reference Case Supplemental Tables, Regional Energy Consumption.

Figure 1-49. *Residual Fuel Oil Demand by Census Region*



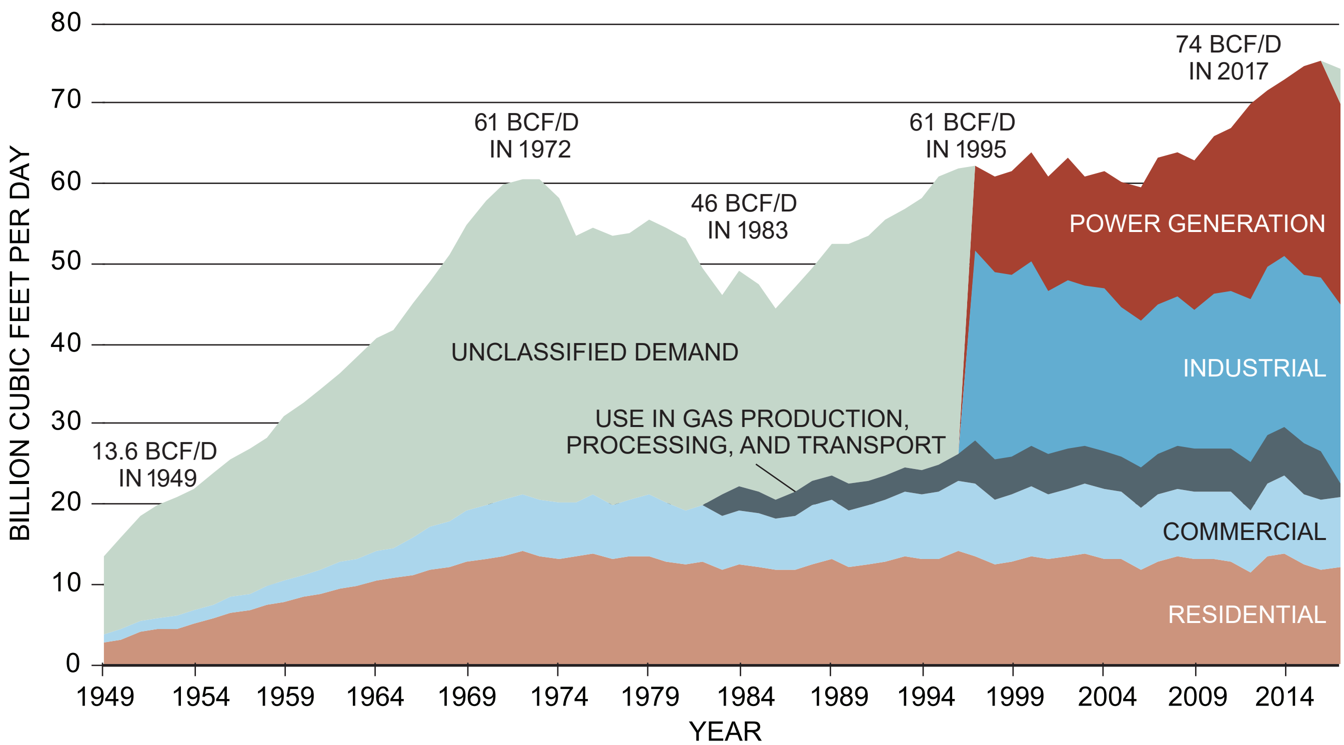
Sources: EIA *Annual Energy Outlook 2019*, Wood Mackenzie Q1 2019, and IHS Markit.

Figure 1-50. *U.S. Natural Gas Demand: Forecast Comparisons* aggressive demand growth forecast is from Wood Mackenzie, with demand increasing by more than 20 BCF/D. However, even the EIA's AEO 2019 Low Oil Price projection has demand growing by more than 5 BCF/D between 2018 and 2040. The wide range of domestic demand is primarily dependent on three main factors: fuel switching in the power sector, industrial demand for natural gas, and use of natural gas in the energy sector. As low-cost shale gas has been produced, power producers have built new, more efficient combined-cycle gas turbine (CCGT) power plants to take advantage of the fuel.

Figure 1-51 illustrates changes in demand over the past several decades by end-use category. The recent increase in U.S. natural gas demand has been driven largely by abundant, inexpensive North American supply and its increased use for power generation in place of coal, oil, and nuclear power plants.

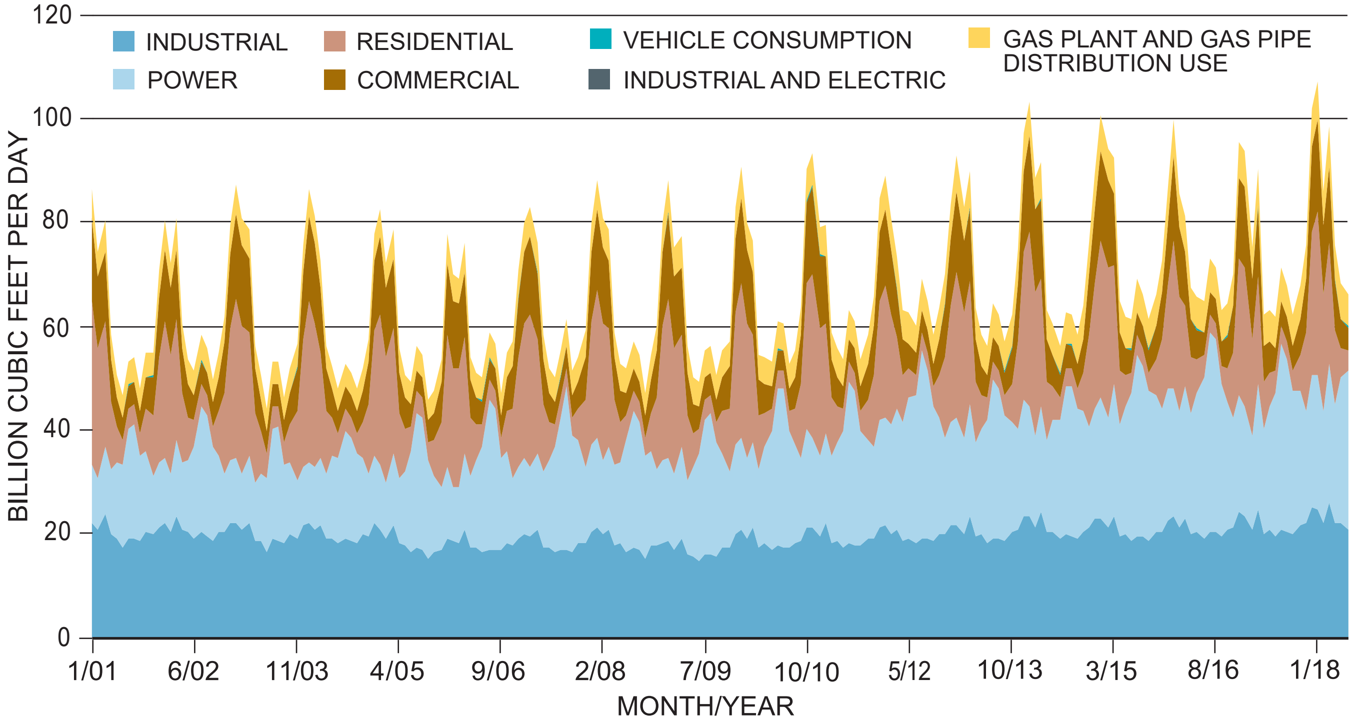
Natural gas demand in the United States is highly cyclical, peaking during the winter months when residential and commercial demand for heating is at its highest. To a lesser extent, the power sector is countercyclical, with higher demand for natural gas-fired power during warm summer months when used for air conditioning (Figure 1-52).

Historically, demand for natural gas is seasonally cyclic which can be problematic in regions without adequate infrastructure. Residential and commercial demand typically grows slowly as new homes and businesses are connected to distribution networks. Industrial users likewise have a fairly consistent demand pattern, with large-scale plants consuming fairly steady volumes of natural gas; demand growth is consistent when new natural gas-fueled industrial facilities are brought online. The main exception is power, where natural gas-fired power plants have historically served as peaking plants, quick to start when electricity demand exceeds supply from baseload capacity. As natural gas prices have fallen, the pattern has changed, with natural gas-fired power plants increasingly used for base loads.



Source: EIA Natural Gas data, "Natural Gas Consumption by End Use."

Figure 1-51. *Natural Gas Demand by Sector*



Source: EIA, Natural Gas, "Natural Gas Consumption by End Use."

Figure 1-52. *U.S. Natural Gas Demand by Sector (monthly), 2001 to 2018*

Finding: U.S. natural gas demand is projected to increase through 2040 with growth driven primarily by the electric power sector.

1. Demand for Natural Gas in the Power Sector

Demand for natural gas in the power sector has seen the most growth over the last decade (Figure 1-53). Growth has come as a function of long-term stable prices that, at times, leave natural gas-fired power less expensive than coal-fired power. In 2018, natural gas was the single largest domestic generation source, comprising 34% of total U.S. generation and 44% of total U.S. capacity. Coal, which was the dominant domestic generating source until 2016,[28] comprised the second largest share of generation and capacity in 2018.

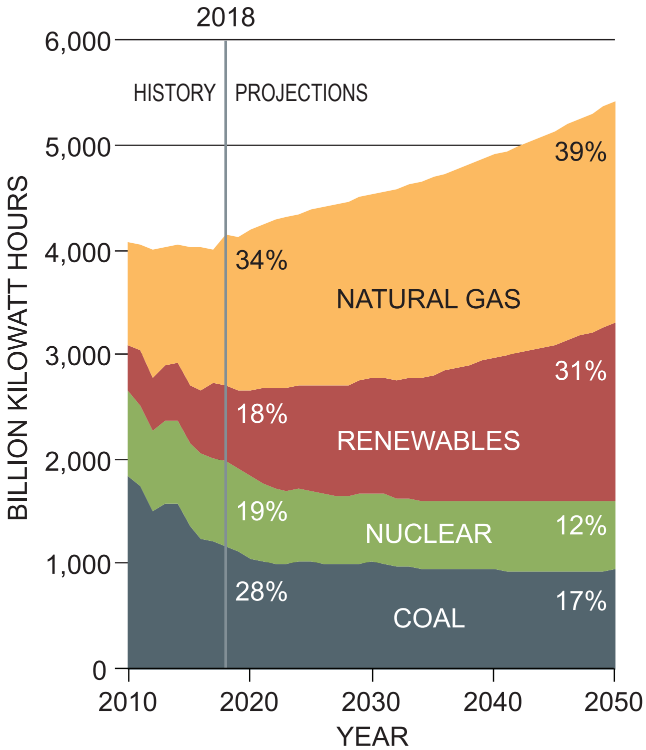
In addition to the high utilization of traditional "gas peaking" plants, new, more efficient CCGT plants have increasingly been built. More than 60% of the electric generating capacity installed in 2018 was fueled by natural gas, with almost all of this new capacity in the form of CCGT.[29] These capacity additions have added new generating capacity to the system and replaced units that are no longer economic. Between 2008 and 2017, coal plants made up almost half of all utility-scale power plant retirements. Another 26% of retirements came from primarily older, less efficient natural gas steam turbine units.[30] This trend is projected to continue in 2019 as shown in Figure 1-54, with 4.5 gigawatt (GW) of coal-fired capacity and 2.2 GW of natural gas-fired capacity expected to be retired.[31]

28 Natural gas first displaced coal as the primary electricity fuel on a monthly basis in April 2015 and on an annual basis in 2016. Source: U.S. Energy Information Administration, *Electric Power Monthly*, Table 1.1. Net Generation by Energy Source: Total (All Sectors), 2009-July 2019, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_1_01 (accessed October 24, 2019).

29 U.S. Energy Information Administration, Today in Energy, March 11, 2019, https://www.eia.gov/todayinenergy/detail.php?id=38632.

30 U.S. Energy Information Administration, Today in Energy, December 19, 2018, https://www.eia.gov/todayinenergy/detail.php?id=37814.

31 This is far less than the 13.7 GW of coal that retired in 2018, the second highest year for coal retirements. U.S. Energy Information Administration, Today in Energy, January 10, 2019, https://www.eia.gov/todayinenergy/detail.php?id=37952.



Source: EIA *Annual Energy Outlook* 2019 Reference Case.

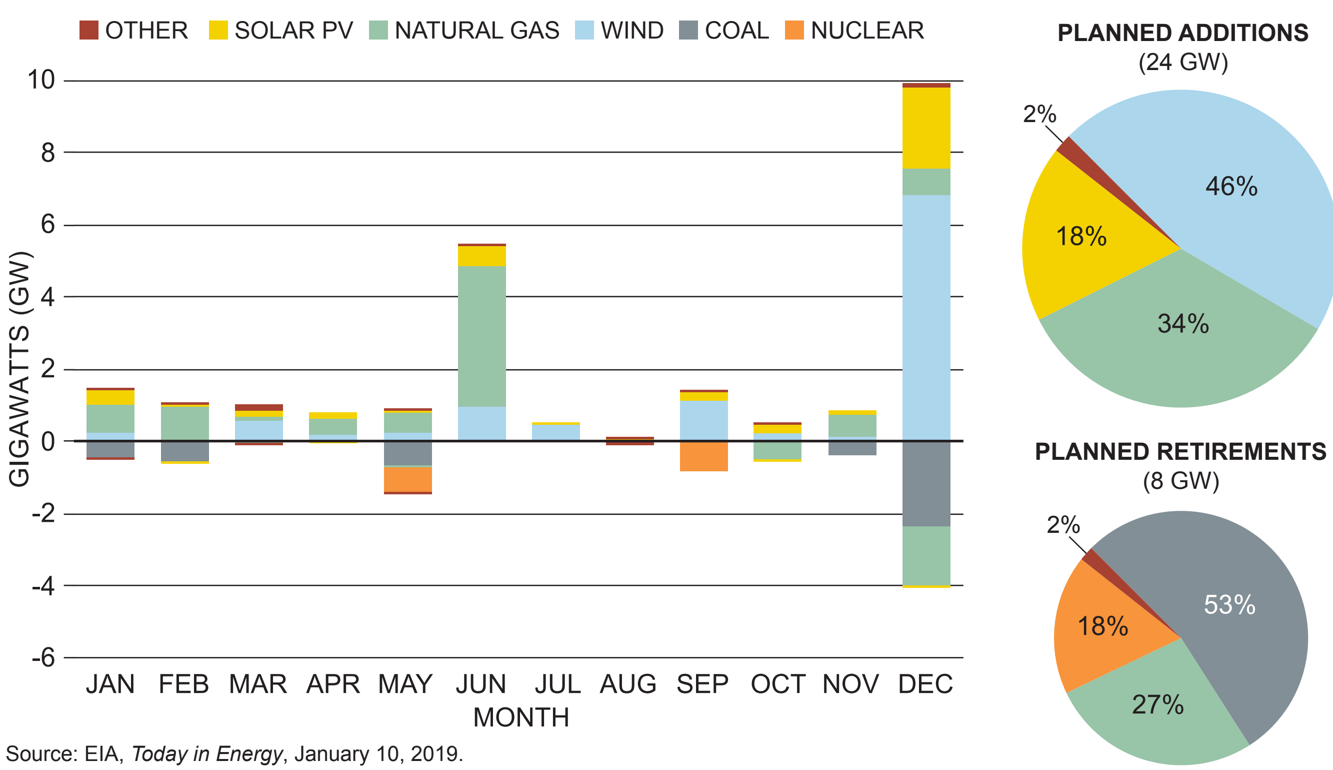
Figure 1-53. *U.S. Electrical Generation Capacity by Fuel*

The increasing utilization of natural gas, wind, and solar generators in the power sector has led to decreased power sector CO_2 emissions. According to an EIA analysis shown in Figure 1-55, between 2005 and 2017 power sector CO_2 emissions declined a total of 3,855 million tonnes, with 2,360 million tonnes attributed to the shift from coal to natural gas, and 1,494 million tonnes attributed to the increase in noncarbon generation sources, such as wind and solar.[32]

Another study by Carbon Brief (a UK-based website covering environment and energy policies)[33] showed that overall CO_2 emissions were 14% lower in 2016 than their 2005 peak, and the largest driver for this was coal to natural gas switching in the power sector, which accounted for 33% of that

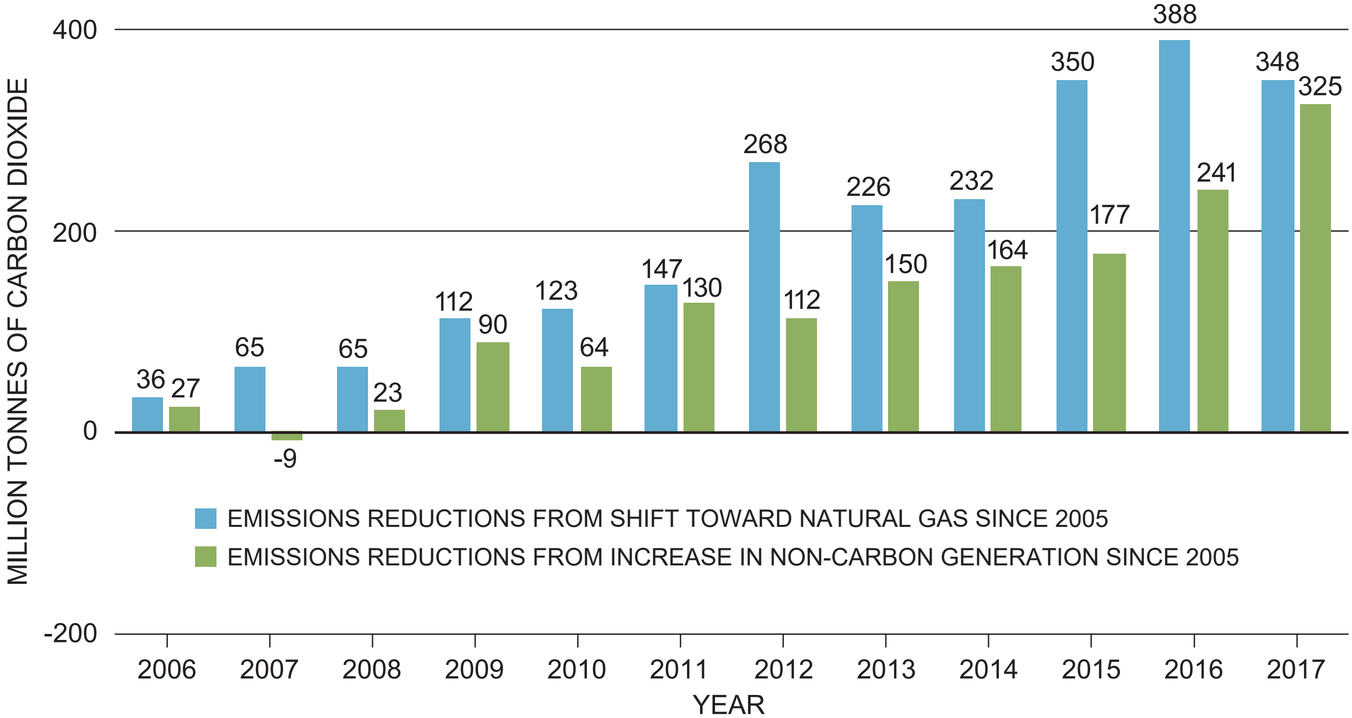
32 U.S. Energy Information Administration, Environment, "U.S. Energy Related Carbon Dioxide Emissions, 2017," https://www.eia.gov/environment/emissions/carbon/.

33 Zeke Hausfather, *Analysis: Why US carbon emissions have fallen 14% since 2005,* Carbon Brief, August 15, 2017, https://www.carbonbrief.org/analysis-why-us-carbon-emissions-have-fallen-14-since-2005.



Source: EIA, *Today in Energy*, January 10, 2019.

Figure 1-54. *2019 Planned Capacity Additions and Scheduled Capacity Retirements*



Source: EIA, *Monthly Energy Review*, August 2018.

Figure 1-55. *Electric Generation CO_2 Savings from Changes in the Fuel Mix since 2005*

reduction. Changes in transport emissions from fewer miles-per-capita, more efficient vehicles, and less air travel emissions account for another 15% of the reduction.

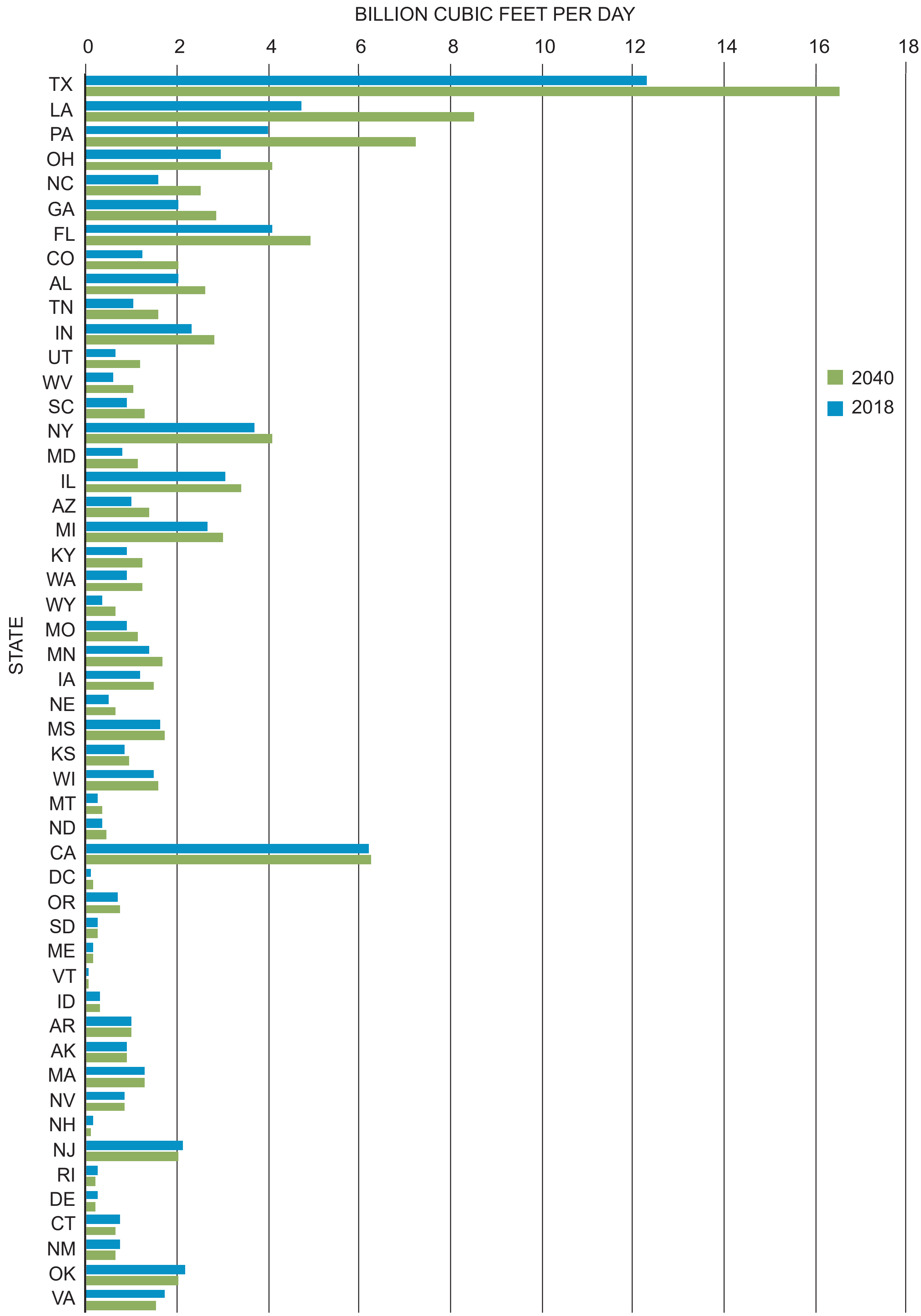
Finding: Increased natural gas use replacing coal to generate electricity has been the single largest contributor to reducing U.S. CO_2 emissions—by 15% since 2005.

2. Natural Gas Demand by State

Natural gas demand is not evenly spread throughout the United States. Figure 1-56 shows the top three states consume approximately 30% of the nation's natural gas—with relatively steady demand for the last 20 years. Texas (~11 BCF/D) and Louisiana (~3.5 to 4.5 BCF/D) dominate natural gas consumption with large industrial centers in each state. California's residential/commercial and large-scale industrial demand likewise require ~6 to 7 BCF/D of natural gas.

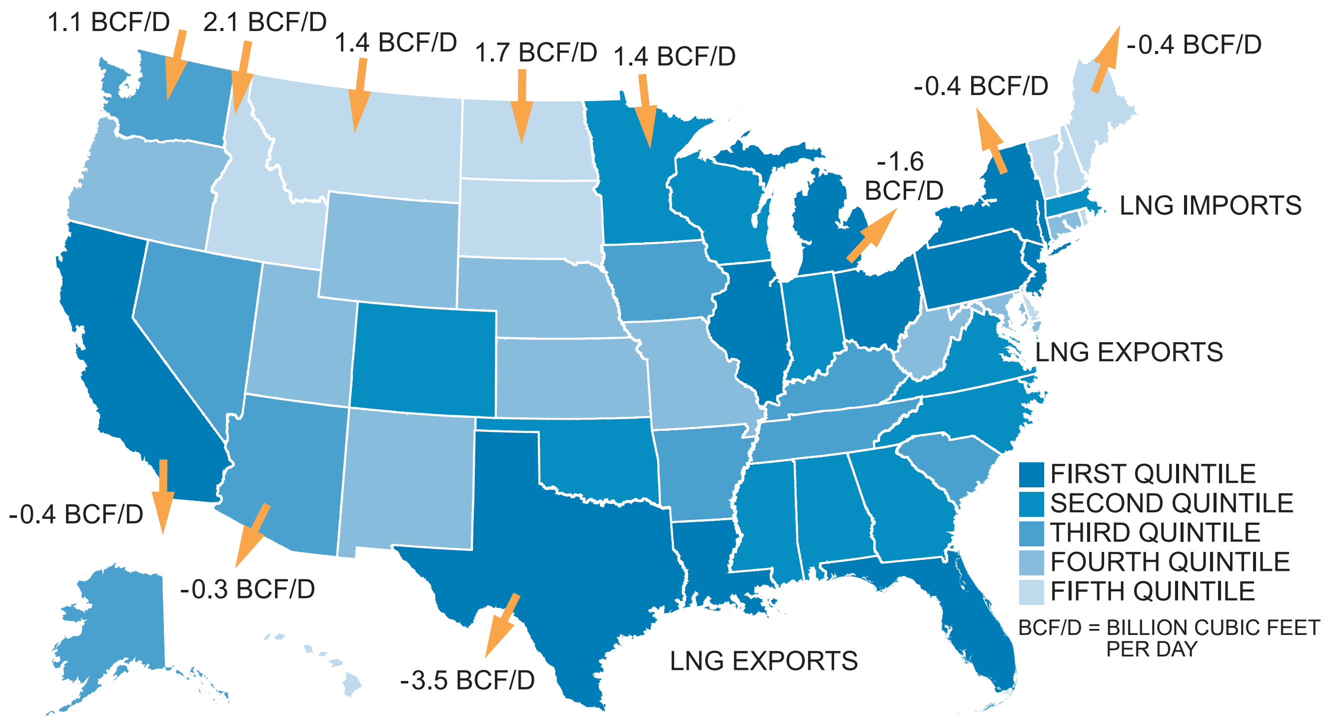
The shale revolution has been a catalyst in the switch to natural gas. Pennsylvania and Florida have both grown to be large-scale natural gas users, each adding ~2 BCF/D of demand from the late 2000s to 2016 (and are expected to continue rising). Demand in both states is being driven by the rising use of natural gas in the power sector as power plant fleets have transitioned from coal or oil to combined-cycle natural gas turbines. The natural gas pipeline grid continues to be modified and expanded to connect new shale basins to market, creating the opportunity for the low-cost, abundant fuel to reduce both power and heating costs.

The main exception to this changing demand dynamic along traditional pipeline routes (Figure 1-57) is New York, where pipeline expansion projects face opposition and power generators face market and structural impediments to entering into contracts necessary for pipeline capacity expansion. Inadequate new pipeline infrastructure leaves the New York and New England region bottlenecked. The impacts of this bottleneck



Sources: Wood Mackenzie Q1 2019 and EIA *Annual Energy Outlook 2019*, Supplemental tables for regional detail.

Figure 1-56. *Projected Change in Gas Demand by State*



Source: EIA, "Natural Gas Consumption by End Use;" and EIA, "Natural Gas U.S. Imports & Exports by State."

Figure 1-57. *North American Natural Gas Demand Intensity Map, including 2016 Demand and Net Pipeline Trade Flows*

during cold weather is discussed in the text box titled "Vignette: The Polar Vortex." Wholesale power prices are on average ~$30 per megawatt hour (MWh) nationally, though limited availability of natural gas at times (especially during cold weather when natural gas is required for heating) has led to wholesale prices as high as $107/MWh (January 2018) and an avoidable reliance on oil-fired and coal-fired power that also has the deleterious effect of higher-carbon emissions.

U.S. natural gas prices are typically referred to using Henry Hub as the indicative price index. After industry deregulation, Henry Hub prices gradually rose with spikes when production was shut in due to hurricanes and as oil prices rose in 2008 (Figure 1-58). The index developed a good correlation with international natural gas prices, but growing shale production led the Henry Hub price to fall in 2008, essentially delinking it from global markets. Henry Hub prices have since become range-bound by the availability of abundant, low-cost supply. This has provided the necessary stability for large-scale consumers to begin relying on natural gas more heavily.

Henry Hub is considered a benchmark indicator because it sits at the confluence of so many conventional and unconventional supply basins, but various hubs around the United States have seen a slightly different pattern of pricing evolve as pipeline networks have been debottlenecked or reversed to accommodate new supply regions. In areas where it is easier to build greenfield pipelines or repurpose existing pipelines, natural gas supply has been quickly connected. For example, most of the grid east of the Rockies is now largely suited to take supply from emerging production regions to demand centers, thus differentials between these hubs are essentially the cost of transportation. A major exception is the Northeast, where local- and state-level opposition has limited new pipeline investments that would close the gap between pricing hubs in shale-rich Appalachia and the Northeast.

VIGNETTE: THE POLAR VORTEX

The impacts of extreme cold weather events on natural gas supplies and the electricity markets illustrate the impacts of natural gas pipeline constraints, particularly in the Northeast and New England. The historic cold weather experienced in January 2014, referred to as the Polar Vortex, tested the performance of natural gas and electricity networks, stressing electric reliability and the functioning of the markets. U.S. daily natural gas demand reached an all time peak on January 7, which exceeded pipeline capacity, requiring record storage withdrawals. High demand during the Polar Vortex event stretched across the Southeast, Mid-Atlantic, and Northeast constraining numerous eastern gas pipelines from the Gulf Coast to the Northeast.

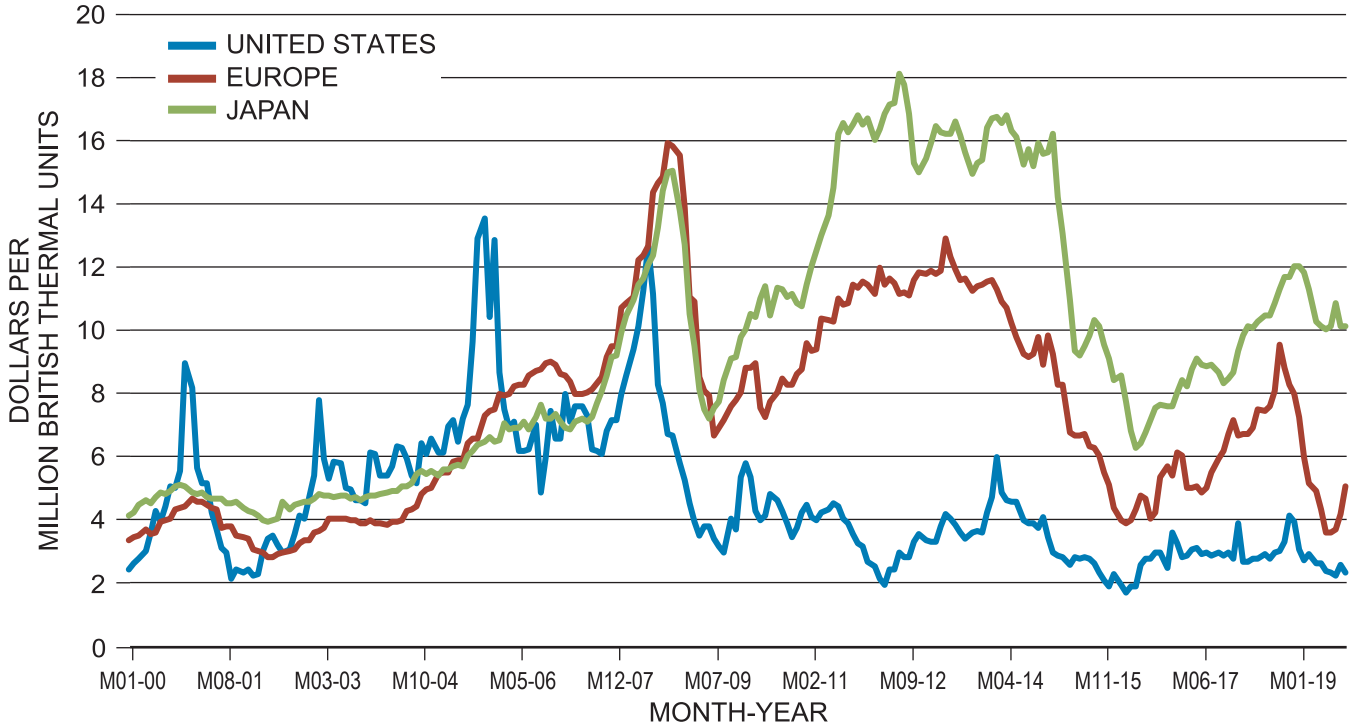
High demand and tight supplies caused spot market natural gas and electricity prices to skyrocket spiking at above $100/MMBTU across the eastern seaboard. Likewise, electricity prices in the organized energy markets across the region experienced sizeable price spikes, as electricity demand rose, and as the markets reflected the price of natural gas. Across the regional electricity markets, natural gas is the marginal fuel playing the lead role in establishing the real time price of electricity. The unprecedented high natural gas prices pushed hourly electricity prices to above $2,000/MWh in the PJM Interconnect, the regional transmission organization, and above $1,000/MWh in several other regional markets.

In areas prone to pipeline constraints during cold weather events, such as in New England, lack of natural gas deliverability results in natural gas-fired power plants being unable to obtain fuel, as pipeline supplies are used by firm shippers to meet heating demand. One consequence is increased operations by coal and oil-fired power plants, as high spot market natural gas prices place other forms of power generation in economic merit. Another result is reliance on imported LNG when demand outstrips the capacity of pipelines serving the region to meet the region's needs. While the rest of the country has been building export projects at former natural gas import locations, New England continues to import natural gas from abroad.

Numerous electricity market refinements have been made since the polar vortex event, including changes to the timing between the natural gas and electricity markets, and structures that allow power plants to better reflect their actual fuel supply costs in the real time electricity markets. Post-event data analysis demonstrates that pipelines that provided more scheduling opportunities and flexibility to shippers were better utilized than others.

Analysis also shows that customers who contracted for firm transportation capacity on natural gas pipelines generally managed to secure gas deliveries. It is well known that competitive power generators do not find it to be in their economic interests to contract with pipeline operators for firm capacity, and rely on interruptible deliveries, notwithstanding that power generation is the largest user of natural gas transported on the interstate pipeline system.

The consequences of bottlenecked systems in the Northeast have come in the form of relatively high energy costs for consumers and businesses, significant and worsening power grid reliability concerns as expressed by New England's Regional Transmission Organization (ISO-New England), and the need to rely on higher-carbon fuels for power generation during peak demand (e.g., oil-fired power), resulting in increased carbon emissions. Though these problems are apparent to varying degrees at different times, they were particularly acute during the Polar Vortex of 2014.



Source: The World Bank, Commodity Price Data: The Pink Sheet, United States (Henry Hub), Europe (TTF), Japan (LNG Import).

Figure 1-58. *Natural Gas Prices, 2000 to 2019*

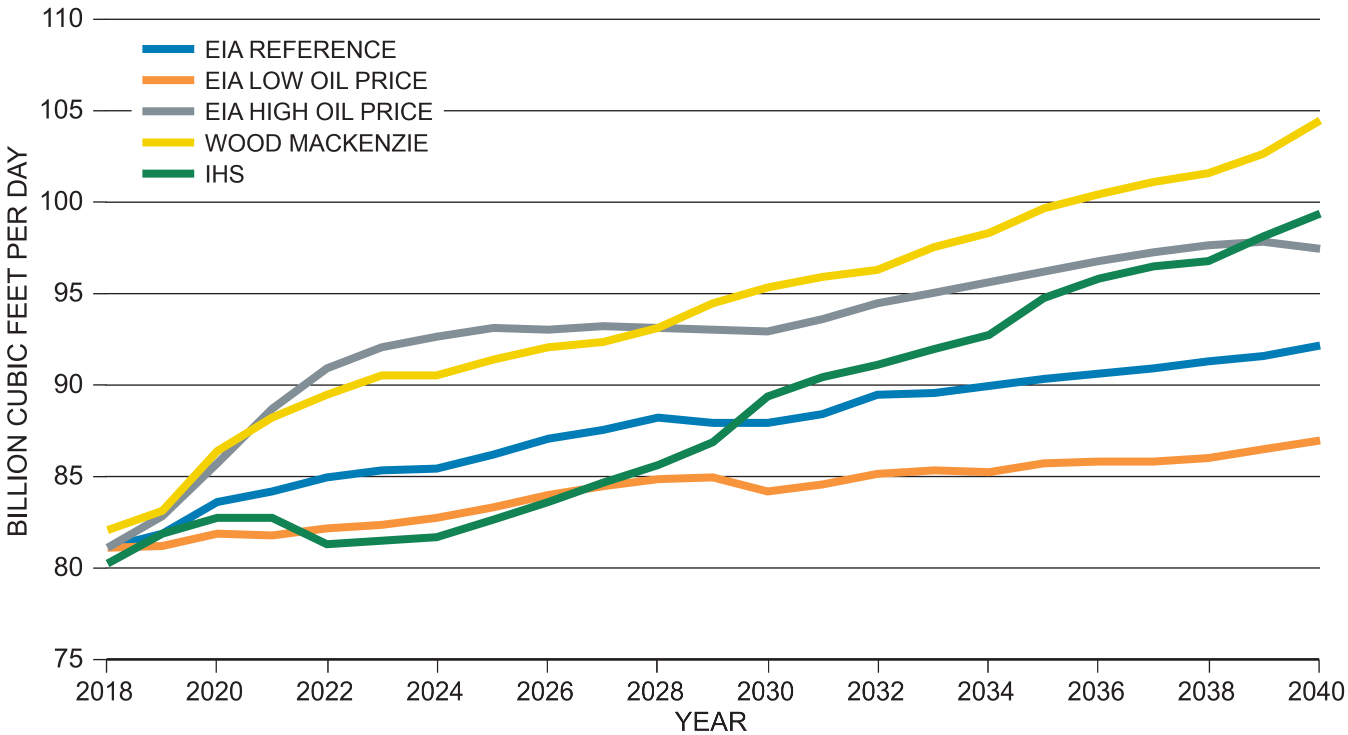
3. Outlook

U.S. natural gas demand is expected to continue rising with the sustained availability of reliable, abundant, and low-cost domestic supplies. Analysts predict continued stable natural gas prices, giving power producers, industrial users, and exporters the confidence to sign long-term agreements.

Domestic demand is forecasted to grow in every scenario analyzed for this report, with a wide range of future demand scenarios (Figure 1-59). Consulting group Wood Mackenzie forecasts the highest demand in 2040 of 104.5 BCF/D with HIS Markit estimating 99 BCF/D of demand. Of the three EIA scenarios analyzed, the Reference Case estimates 92.2 BCF/D and high and low oil price scenarios estimate a range between 87-97.4 BCF/D. Oil price assumptions impact these demand forecasts because a large part of forecasted natural gas production is associated with crude oil production and will only be produced if oil prices support drilling.

The wide range of domestic demand growth is primarily dependent on three main factors: fuel switching in the power sector, industrial demand for natural gas, and use of natural gas in the energy sector. As low-cost shale gas has been produced, power producers have built new, more efficient CCGT power plants to take advantage of the fuel.

Heat rate, a measure of power plant efficiency, is much lower in a CCGT plant than in coal—and due to technological improvements, efficiency is improving. The EIA estimates that the average heat rate for U.S. natural gas-fired power plant fleet has decreased from 8,403 BTU per kilowatt hour (KWh) in 2007 to 7,812 BTU per KWh in 2017—demonstrating a 7% improvement in efficiency. Conversely, the coal plant fleet has retained a consistent average of 10,442 BTU per KWh from 2007 to 2017. The combination of historically low natural gas prices and more efficient power production makes natural gas even more attractive than coal. Additionally, the lower-carbon profile of natural gas-fired generation has made the fuel



Sources: EIA *Annual Energy Outlook 2019*, Wood Mackenzie Q1 2019, and IHS Markit.

Figure 1-59. *U.S. Natural Gas Demand: Forecast Comparisons*

preferable in jurisdictions with greenhouse gas (GHG) reduction mandates. The major limit on the potential is access to supply—a problem much of the East Coast states have solved with new, large-scale pipeline infrastructure. As discussed, the outlier is the U.S. Northeast, particularly in New York, where market forces and opposition to new pipelines has limited the ability to access low-cost power despite the proximity of the Marcellus and Utica shale formation.

Natural gas consumption in other sectors is much more predictable. Industrial demand is largely increasing along the U.S. Gulf Coast, where new petrochemical plants are under construction to take advantage of the low-cost feedstock and the proximity to tidewater and international markets. Finally, the use of natural gas to produce oil and natural gas rises as production increases.

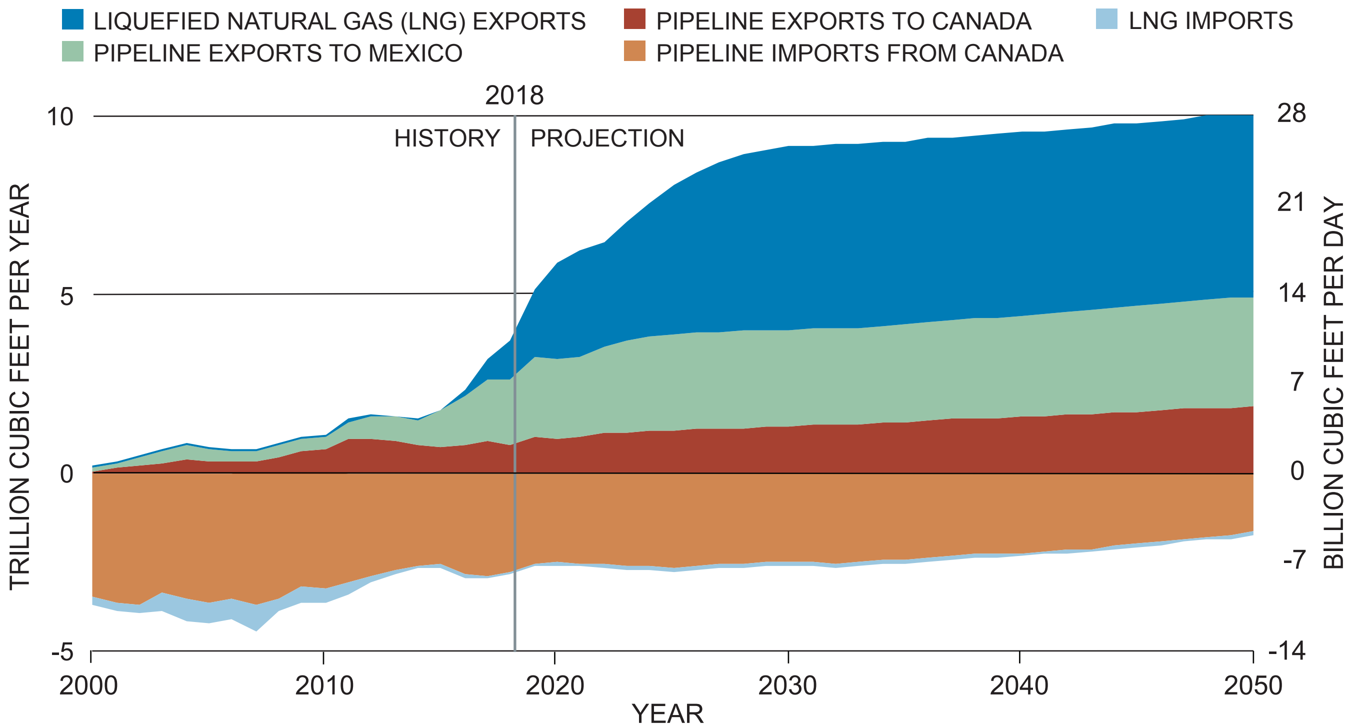
While strong demand growth is expected in the natural gas market, natural gas production growth is expected to outpace demand. Exports—both to Mexico via pipeline and as LNG to global markets—are expected to continue to grow as shown in the EIA AEO 2019 Reference projection in Figure 1-60. LNG is expected to be a large component of demand for U.S. natural gas: by 2040, of the ~104 BCF/D of supply, the IEA forecasts roughly 10% will be exported as LNG.

4. LNG Major Driver of Future Growth

The shift from expensive supply to abundant, low-cost natural gas production in the United States in the last decade has opened new opportunities to use natural gas. One major growing source of demand comes in the form of exports, both as LNG and via pipeline to Mexico and Canada (Figure 1-61).

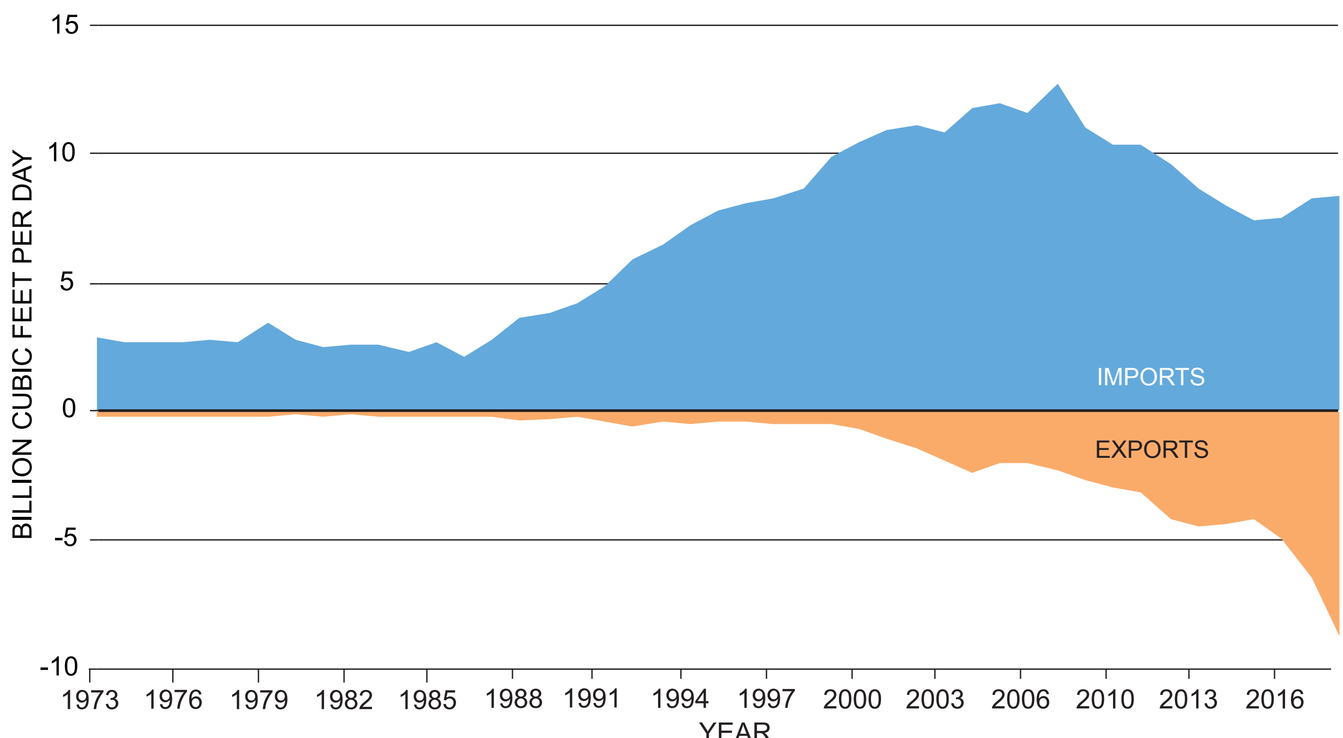
LNG is raw methane cooled to -260°F (-160°C) and shipped in this cryogenic state, allowing easier ocean transport. In 2017, 18 countries exported LNG and shipped the fuel to 36 importing markets.

In the 2018 World Energy Outlook, the IEA forecasts global natural gas trade to grow from



Source: EIA, *Annual Energy Outlook 2019.*

Figure 1-60. *Natural Gas Trade*



Source: EIA, *Today in Energy*, March 19, 2018.

Figure 1-61. *U.S. Natural Gas Trade, 1973 to 2017*

31 BCF/D in 2017 to 73.3 BCF/D in 2040. Historically, Japan and Korea have been the dominant LNG importers, though the IEA forecasts Chinese natural gas demand to grow to ~70 BCF/D by 2040, one-third of which will be imported as LNG. Collectively, other developing Asia Pacific markets have the ability to import another 15 BCF/D of LNG by 2040—up from a base of zero imports in 2017. Given that U.S. LNG will in some cases be replacing higher-carbon fuels, there is the potential for significant reductions in global GHG emissions because of increased exports.[34] With abundant feedstock and limited domestic demand, the United States is well positioned to contribute significantly to growing LNG trade.

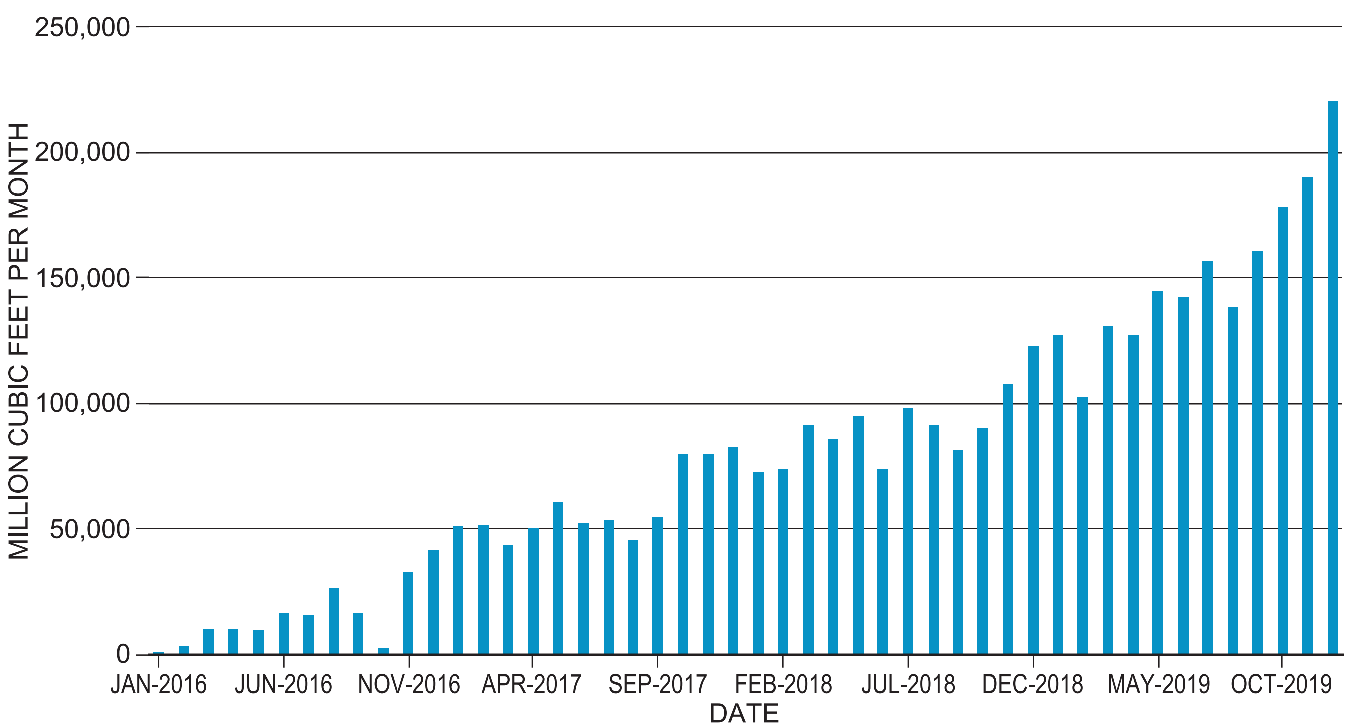
5. U.S. LNG Exports

In the early 2000s, the United States was expected to import natural gas from abroad to satisfy domestic demand by the late 2010s, and a number of companies had built LNG import terminals along the U.S. Gulf Coast and East Coast to answer that call. High natural gas prices incentivized producers to take another look at shale gas reserves and, with the combination of directional drilling and hydraulic fracturing, developed methods to produce natural gas from previously uneconomic plays. The shale revolution provided sufficient domestic production to supplant the need for imports, and terminal owners began eyeing opportunities to use these existing assets to export natural gas instead.

Cheniere Energy's Sabine Pass LNG was the first project to bring a liquefaction train online in January 2016. Since then, the project (located near the Texas-Louisiana border on the U.S. Gulf Coast) has added an additional three trains with a fifth scheduled for completion in 2019. Dominion Energy's Cove Point liquefaction plant (located on the Chesapeake Bay, south of Washington, DC) came on-stream in March 2018.

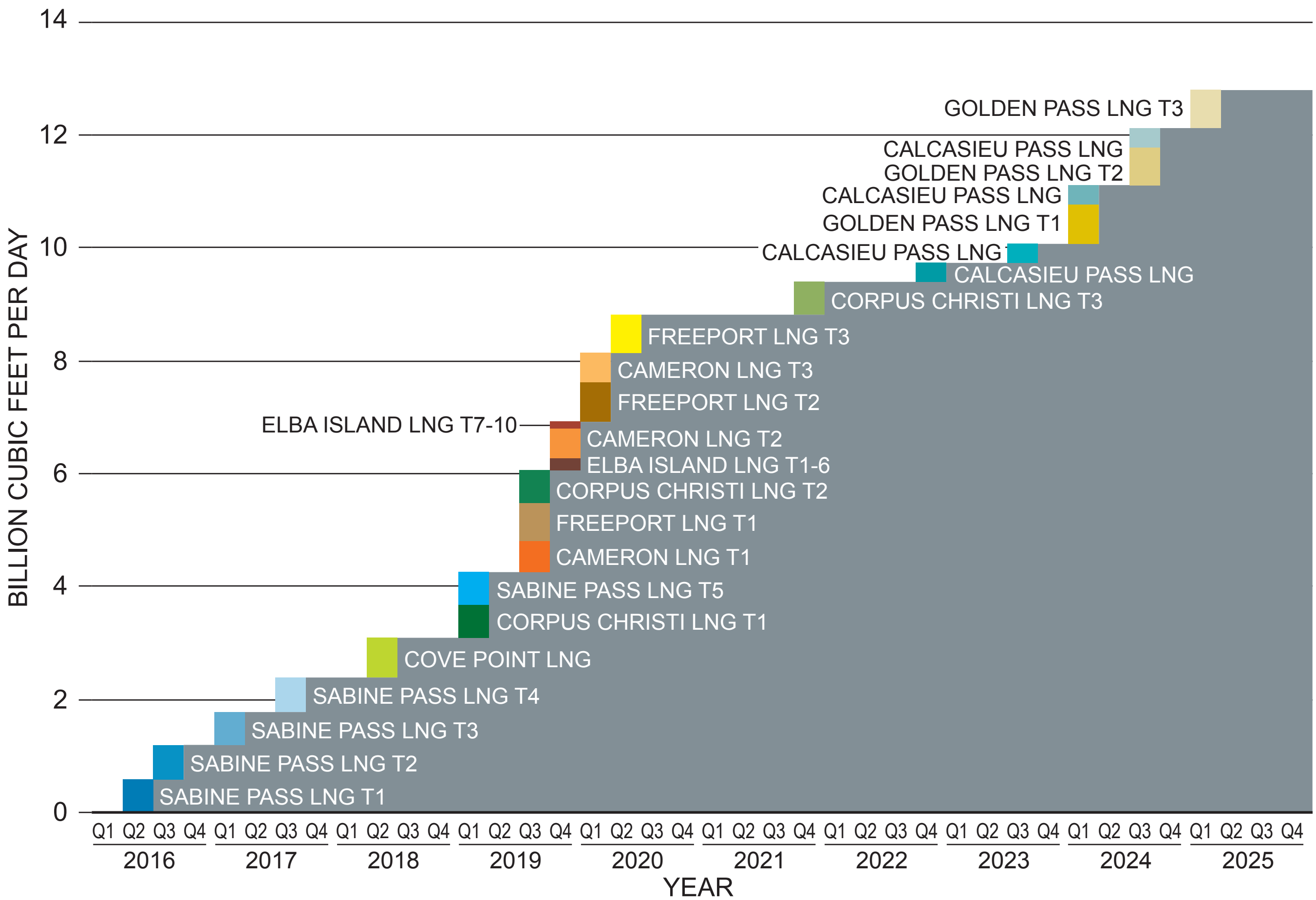
To date, roughly half of U.S. LNG exports shown in Figure 1-62 have been sent to Asia Pacific

34 International Energy Agency, "Natural Gas," https://www.iea.org/topics/naturalgas/ (accessed October 24, 2019).



Source: EIA, Natural Gas date, Liquefied U.S. Natural Gas Exports (Accessed March 31, 2020).

Figure 1-62. *U.S. LNG Exports, 2015 to 2018*



Source: EIA Database of U.S. LNG export facilities, Company Investor Presentations.

Figure 1-63. *Potential North American LNG Export Capacity by Project*

markets, with another third destined for Latin America. In Asia Pacific, LNG displaces higher-carbon fuel power generation. In Latin America, it is used to compliment hydropower generation during seasonal periods of drought.

By 2025, LNG plants currently operational or under construction in the United States (Figure 1-63) will create the opportunity to export ~11.5 BCF/D of natural gas supplies from 28 liquefaction trains at seven projects. Most of the projects have a capacity to liquefy 600 to 700 MMCF/D of natural gas, though Kinder Morgan's Elba Island LNG project comprises 10 small-scale trains that require ~30 MMCF/D of natural gas each.

The capacity currently under construction will make the United States the third largest LNG exporter in the world, behind Qatar and Australia. This is an astounding reversal when, just 10 years ago, the United States was expected to become one of the largest LNG importers by the late 2010s.

Another nearly three dozen projects, representing ~50 BCF/D of export capacity, have been proposed to be built around the United States. While it is unlikely that all of these projects will be built, several have the potential to arbitrage low-cost U.S. natural gas supplies to higher-priced foreign markets. Proposals include a wide variety of projects that vary in size from 40 MMCF/D to 900 BCF/D of export capacity. Technologies vary as well, including small-scale modular concepts, floating proposals, and large-scale expansions at existing terminals.

In addition to the U.S. Gulf Coast (where most projects have been proposed), proposed projects seek to export U.S. natural gas from the West Coast of the United States and Mexico and the East Coast of the United States and Canada.

F. NGLs and Petrochemicals

1. NGLs

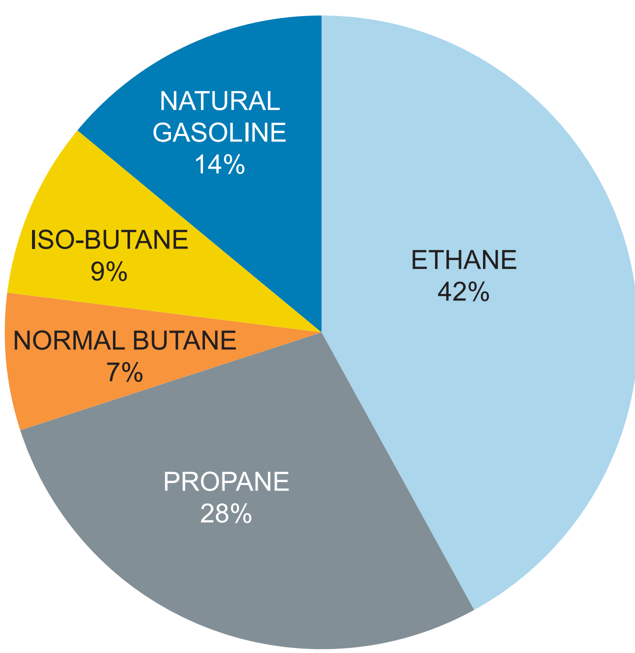
NGLs are composed of all hydrocarbons heavier than methane that are produced from natural gas wells (nonassociated gas) or from light gases separated from crude oil production (associated gas). In the late 1990s and early 2000s, due to declining oil and natural gas production, domestic supplies of NGLs were not adequate to meet demand, resulting in the United States being a net importer of propane, butane, and C5+ naphtha.

With the shale revolution, increased production of all NGLs has resulted in a role reversal, whereby the United States is now the largest exporter of ethane and propane globally. Furthermore, the sharp increase in NGL supply has resulted in a petrochemical investment boom, as advantaged feedstocks and competitively priced natural gas has encouraged more than $150 billion in new chemical/petrochemical investment projects since 2008.

The recovered NGL barrel, which typically contains ethane, propane, butane, and pentanes plus, is called Y-grade. The NGL barrel, or Y-grade, product is typically pumped via pipeline (some can be railed or trucked) to fractionation plants on the Gulf Coast (Mont Belvieu, TX; Freeport, TX; Corpus Christi, TX; or the Lower Mississippi River in Louisiana) to be separated into its individual components for further processing, sales, or export. Fractionation capacity also exists in Kansas (Conway), Oklahoma; Marcus Hook, PA; and in the Midwest. Just as the majority of petrochemical demand for NGL is centered on the TX/LA Gulf Coast, a majority of the NGL fractionation is also located in the same region.

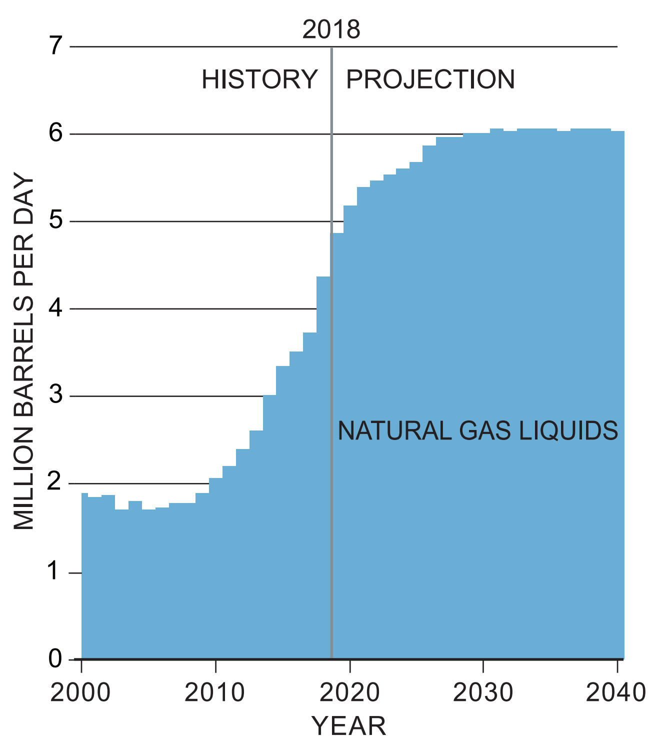
Figure 1-64 reflects the composition of a typical NGL barrel, but different producing regions and formations may see composition vary significantly.

NGPL production has grown dramatically with expanding crude oil and natural gas production in the United States. From a low of 1.7 MMB/D in 2005, production has more than doubled in 2018, exceeding 4.3 MMB/D (Figure 1-65). With



Sources: EIA *Annual Energy Outlook 2019* and Argus Consulting Services.

Figure 1-64. *Make Up of Natural Gas Liquid Barrel, Volume Percent*



Source: EIA, *Annual Energy Outlook 2019.*

Figure 1-65. *Total NGL Production* oil and natural gas production expected to continue to expand through 2025, NGPL production is expected to exceed 6.0 MMB/D by 2029 and then expand only marginally thereafter.

Ethane is normally the dominant NGL component recovered from raw natural gas or associated gas from crude oil production, typically around 42% by volume.

Ethane supplies from crude oil and natural gas production in the Midcontinent (Oklahoma, Kansas, North Dakota), Texas, Louisiana, and Mississippi/Alabama fields are recovered via Y-grade fractionation and processed into petrochemicals. In other regions such as the Rocky Mountains, ethane is typically left in the natural gas as market conditions and logistics discourage recovery. As new production regions such as the Bakken and Marcellus/Utica shales were developed, ethane produced in the raw shale gas was rejected, or left in the shale gas for domestic consumption, due to lack of infrastructure and lack of a local market demand. In some cases, particularly in the Bakken, associated gas was allowed to be flared (burned) with no recovery until pipelines and natural gas processing plants could be constructed and become operational. As local and state governments began to restrict flaring, investment followed.

In complexes where oil refineries are integrated with petrochemical complexes with steam crackers, the ethane from the refinery can also be separated from refinery natural gas streams and used for petrochemical production.

Today, U.S. ethane has three markets—domestic petrochemicals, exports to global petrochemical producers, and use as a fuel as a component of natural gas. Natural gas producers look at the value of ethane as fuel versus the market value of the ethane for petrochemicals (domestic or export) less their logistics costs to determine whether to recover the ethane or leave it in natural gas. Depending on the economics of recovery versus rejection, it is estimated that more than 400,000 B/D of recoverable ethane remains in the U.S. natural gas supply.

The majority of ethane for petrochemical use is in the production of ethylene via steam cracking, which is the building block for polyethylene plastic and other copolymers.

Even prior to the shale oil and natural gas revolution, the U.S. ethylene industry had capitalized on the available ethane from the domestic oil and natural gas industry, with more than 50% of all domestic ethylene production coming from ethane feedstock. But, growth of ethylene supply based on ethane feedstock was stymied as the available economic ethane supplies were depleted. As noted earlier, this constraint changed with the shale revolution, resulting in massive investments in petrochemical capacity to meet growing demand for plastics and various chemicals (see Figure 1-66). Note that Figure 1-68 does not account for rejected ethane, which either does not have a current outlet or is not yet economical to recover.

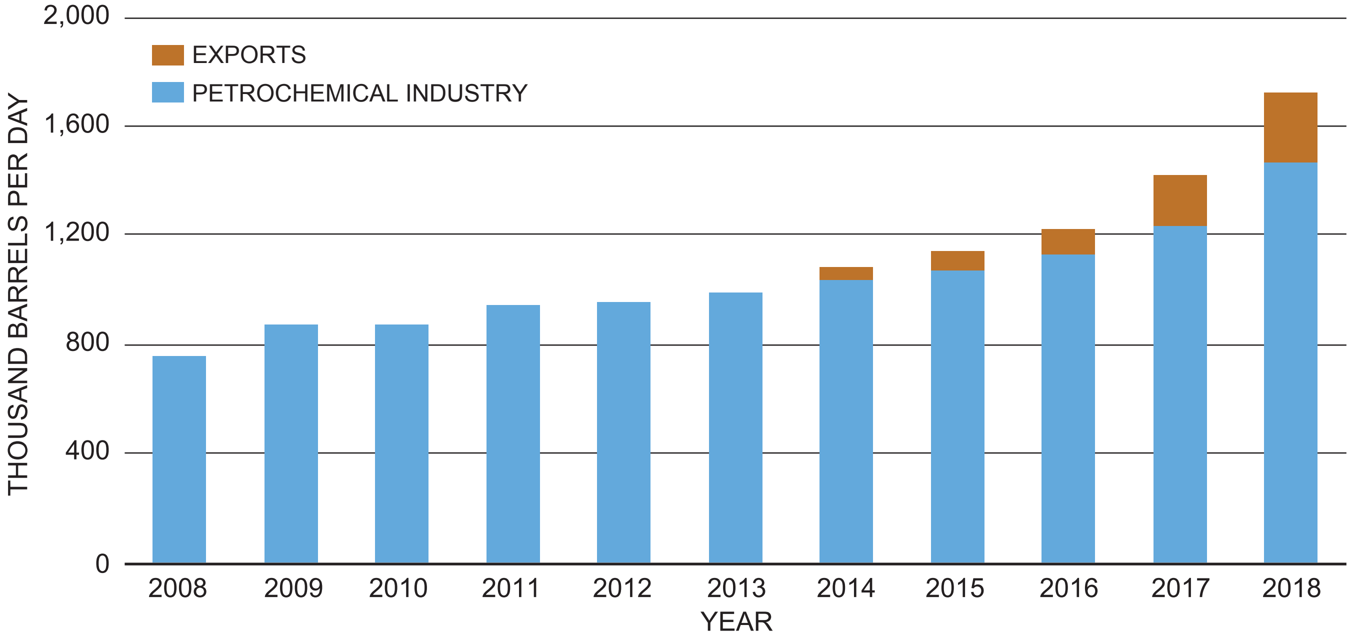
With the growth of ethane production and considering existing ethane export capacity located in North Dakota (pipeline to Canadian steam crackers), Ohio (pipeline to Canadian steam crackers), Marcus Hook (supplies ethane to Europe steam crackers), and Mont Belvieu (exports to Europe, Mexico, Brazil, and India), by the fourth quarter of 2018, the United States was the largest producer and exporter of ethane (Figure 1-67). Exports, diagrammed in Figure 1-67, reached more than 250,000 B/D on average in 2018.

As shown in Figure 1-68, EIA projects ethane production will continue to grow.

Propane is the most widely traded natural gas liquid in the world. The product has many end-use markets, including residential heating and cooking, commercial, agriculture, transportation, and as an industrial use that includes feedstock for petrochemical production (Figure 1-69).

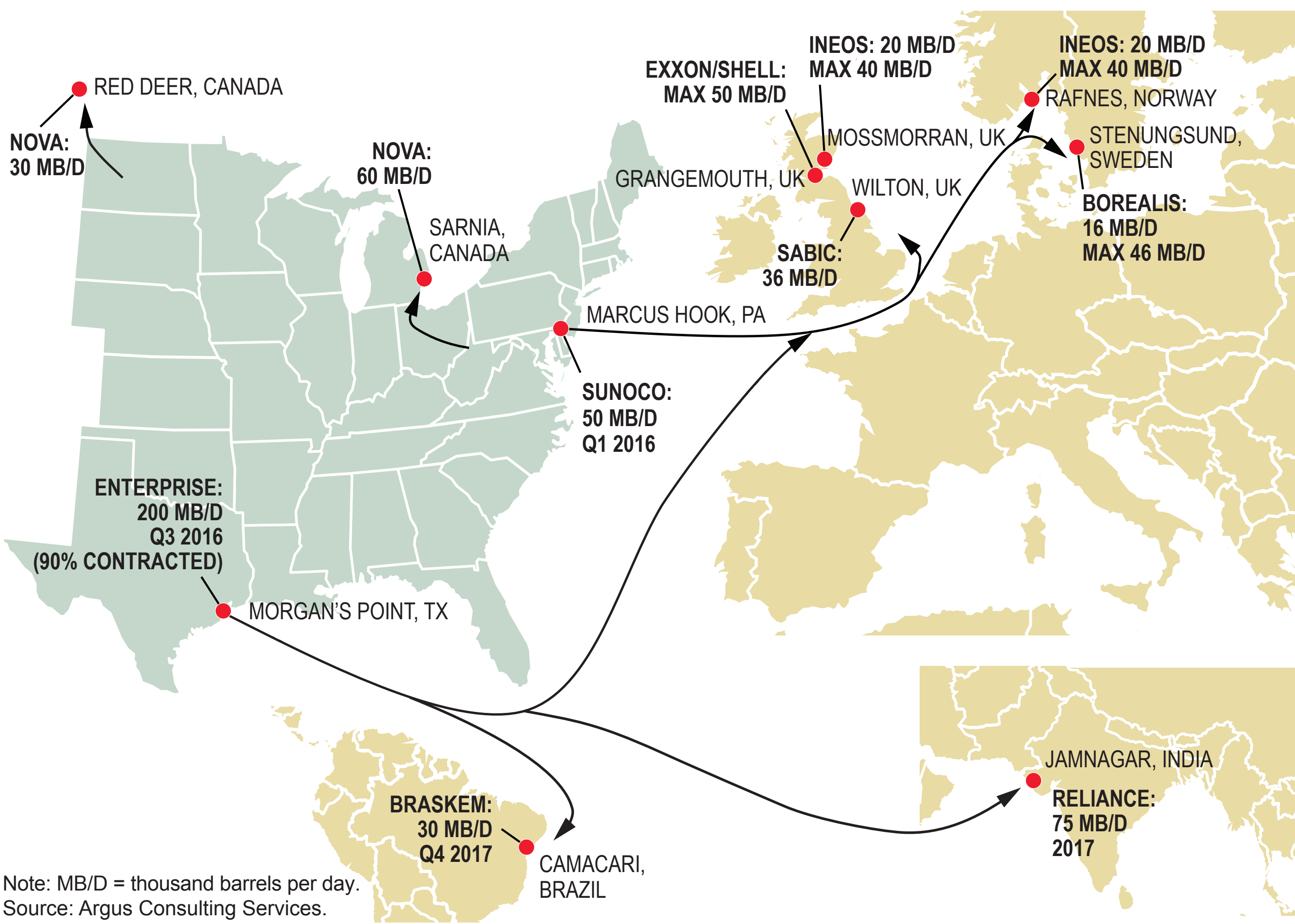
Propane, like ethane, is supplied from three sources: as a component of raw natural gas produced from a hydrocarbon formation (nonassociated gas); from the gases associated with crude oil production (associated gas); or as a byproduct of the oil refining process.

Propane is easily transported by pipeline or in a variety of ships designed to transport propane and butane cargoes. Propane has been traded



Source: EIA, Petroleum & Other Liquids, Supply and Disposition, Ethane.

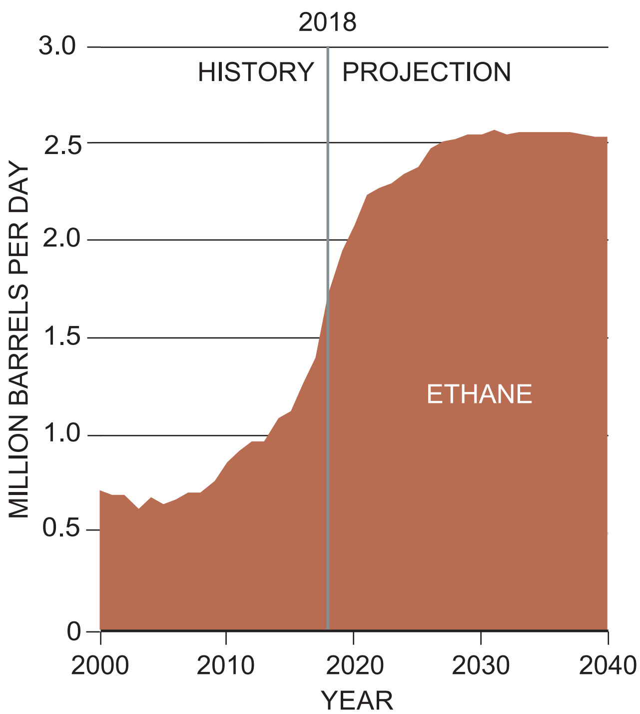
Figure 1-66. *U.S. Ethane Demand*



Note: MB/D = thousand barrels per day.
Source: Argus Consulting Services.

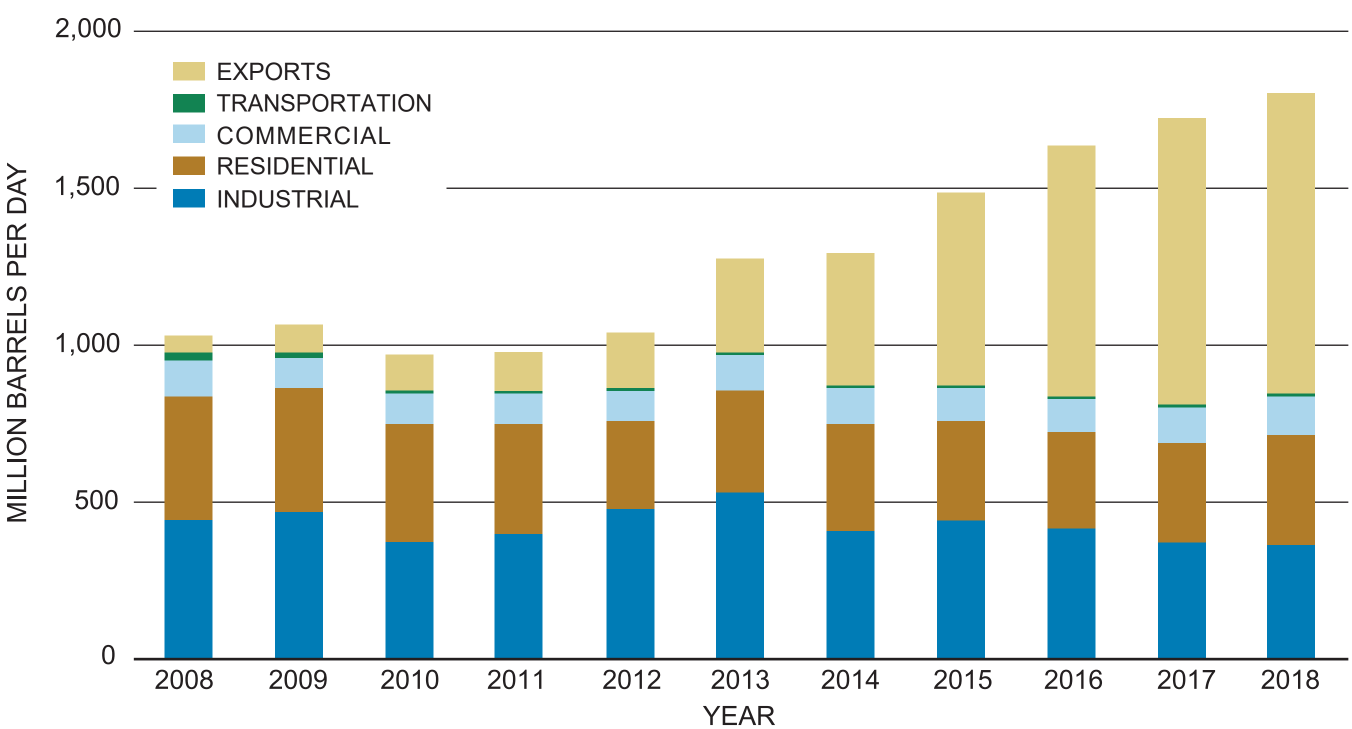
Figure 1-67. *U.S. Ethane Exports and Destination* internationally since the late 1960s, and approximately 30% of total global propane supply is involved in global trade. Until recently, the Middle East was the key incremental supplier of propane to the world. The use of hydraulic fracturing in the United States has resulted in growing production of natural gas and crude oil, which has almost doubled daily production of propane. In turn, this has dramatically changed the global propane market, and growth in U.S. propane production and exports are expected to continue. Up until 2012, the United States was a net importer of propane. The United States is now the largest exporter of propane in the world, supplying markets in Latin America, Europe, and Asia as well as other regions.

Residential heating and cooking demand is limited to mainly rural areas or locations where alternative fuels such as natural gas are not available or where there is no local distribution company to deliver natural gas. Customers are supplied by truck delivery with on-site storage of propane. Use of propane for gas grills also falls in this category.



Source: EIA, *Annual Energy Outlook 2019*.

Figure 1-68. *U.S. Recovered Ethane*



Source: EIA, Petroleum & Other Liquids, Supply and Disposition, Propane.

Figure 1-69. *U.S. Propane Demand*

Commercial customers are businesses that typically use propane as fuel for their operations along with heating or cooling. Restaurants or other food preparation services can use propane for preparing food for their customers.

Transportation is a small segment of demand that uses propane as motor vehicle fuel, largely in rural areas. The vehicle must have supplemental storage (high pressure tanks) and have its fuel injection system modified for use of propane. Use of propane for motor vehicles is much more widespread in Europe, Latin America, and the Middle East.

Industrial demand for propane is the second largest demand segment in the United States after residential. This segment includes petrochemicals but has seen growth slow as propane is replaced by ethane in some petrochemical segments. In the petrochemical segment, one area of growth is capacity to convert propane to a more valuable petrochemical, propylene. Conversion of propane to propylene has more than doubled in value in the past 5 years, via a process called propane dehydrogenation. There are now four dehydrogenation units operating in the United States, with plans for several additional units (Table 1-4).

As noted previously, the United States is now the largest exporter of propane globally, serving markets in Latin America, Europe, and Asia. It competes with propane supplies from the Middle East in the Asia market, mainly in China. As oil and natural gas production is expected to continue to expand over the next 5 years, growth in propane exports is expected to continue. Propane production from domestic oil and natural gas production is expected to increase to 1.8 MMB/D by 2028 (Figure 1-70) before leveling off as hydrocarbon production is also expected to peak between 2025 to 2030 in the United States.

Butane has two forms. One is a straight-chain, four-carbon molecule called normal butane; the other is a branched four-carbon molecule called isobutane. The two forms of butane have different boiling points and densities, along with different vapor pressures. Both molecules must be stored at more than 70 psig pressure (depending on temperature) as they are gases at ambient conditions.

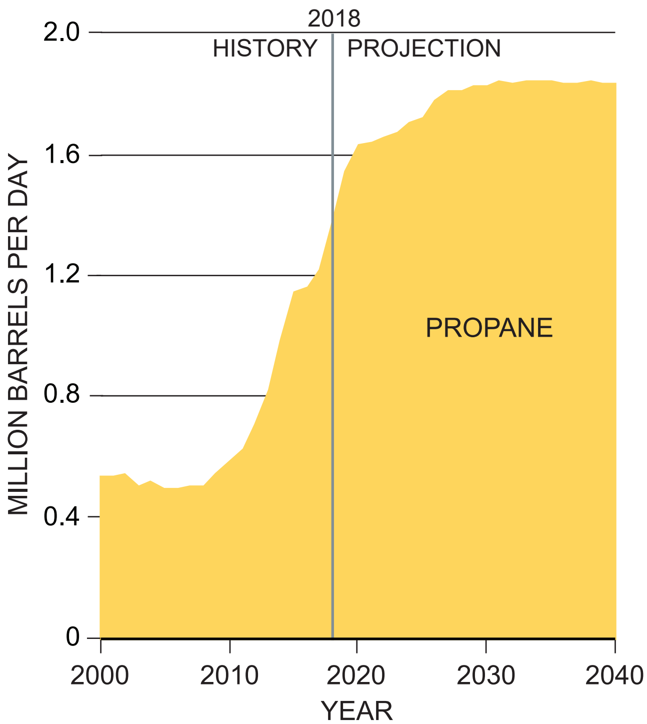
In the United States, butane demand (Figure 1-71) is dominated by gasoline blending, either directly or indirectly after passing through an alkylation unit to make high octane blendstock. Petrochemical demand, mainly into steam cracking/ethylene production, is a distant second. Other

FID* Projects Company	Location	Capacity (000 t/yr)	Technology	Comments
Flint Hills Resources	Houston, TX	650	Lummus Catofin	Operational since 2010
Dow	Freeport, TX	750	UOP Oleflex	Operational since 2015
Enterprise	Mont Belvieu, TX	750	Lummus Catofin	Operating since 2018
InterPipeline	Alberta, Canada	525	UOP Oleflex	Projected 4Q 2021
Pembina/PIC	Alberta, Canada	500	UOP Oleflex	Projected 2Q 2023
Formosa Plastics	Point Comfort, TX	600	STAR	Projected 2Q2021
Dow	Plaquemine, LA	100	Dow	Projected 2021
Enterprise II	Mont Belvieu, TX	825	UOP Oleflex	Projected 2Q2023
Flint Hills Resources II	Gulf Coast	500	Dow	Projected 2023
Appalachia Hub	WV, OH, KY			Under development

*FID means Final Investment Decision has been announced.

Source: Argus Consulting Services.

Table 1-4. *Propane Dehydrogenation Units, North American Projects*



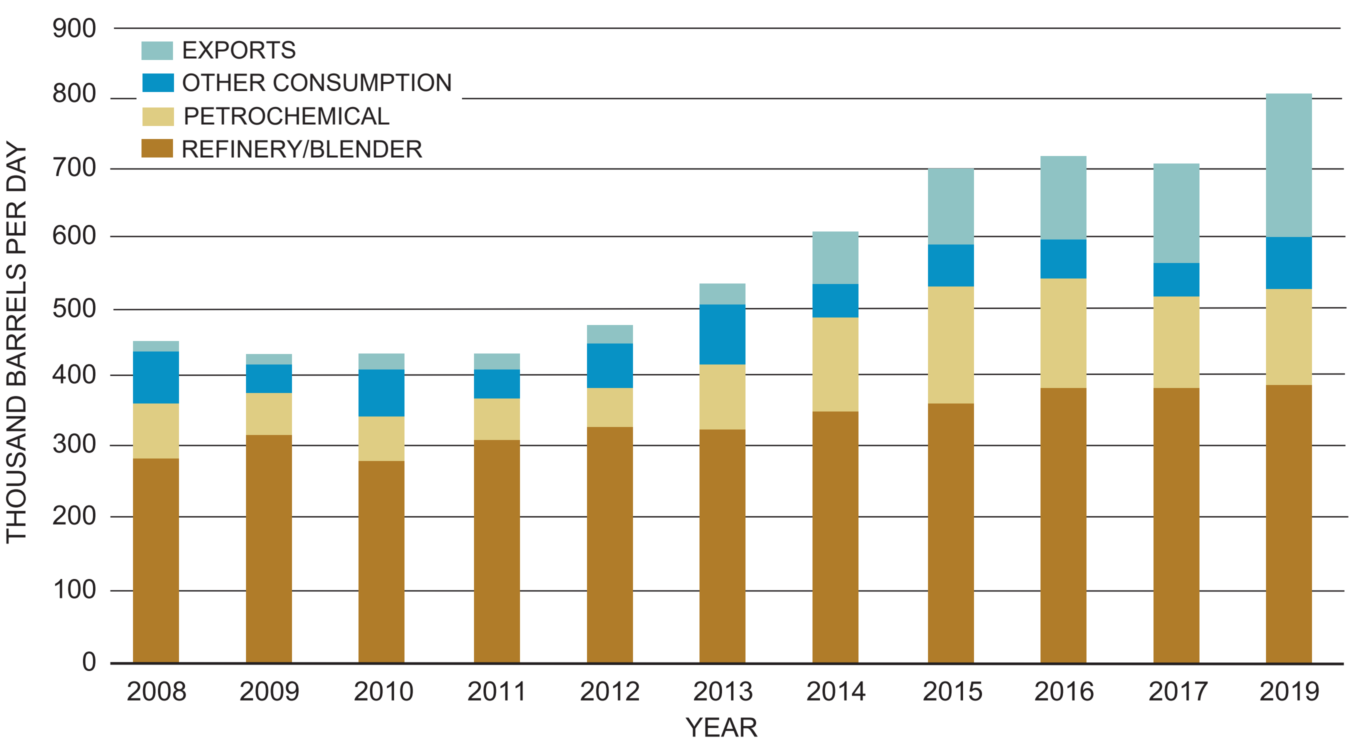
Source: EIA, *Annual Energy Outlook 2019*.

Figure 1-70. *U.S. Propane Production*

consumption includes residential and commercial uses. Exports have seen significant growth. Figure 1-72 shows butane production.

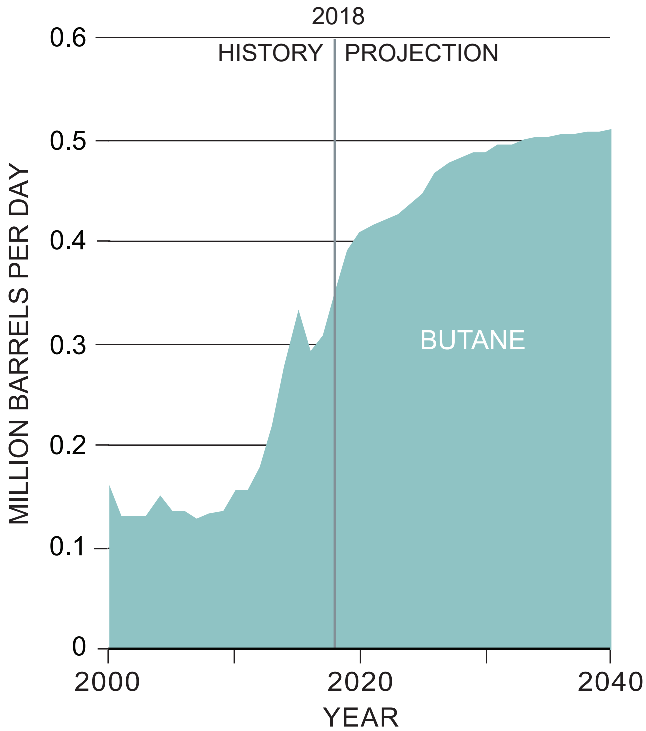
Natural Gasoline/Pentane Plus is the term given to the heaviest (highest density) NGL stream that comes from oil and natural gas production. This stream typically contains molecules of five, six, seven, and even eight carbons. All of the molecules are liquids at room temperature.

As the first name implies, with limitations, this stream can be blended directly into gasoline at refineries or other production locations. In the 1960s and 1970s, blending of natural gasoline for motor fuel production was widespread, due to the ability to use lead to increase octane. Pentane plus or natural gasoline is typically low octane (55-60 research plus motor divided by two), while finished regular gasoline is 87 R+M/2. Natural gasoline can have high levels of sulfur (200 to 300 ppm) and with the U.S. domestic sulfur limit set at 10 ppm, refiners are challenged to blend the stream into domestic gasoline for sales. However, refiners that



Source: EIA, Petroleum & Other Liquids, Supply and Disposition, Butane.

Figure 1-71. *U.S. Butane Demand*



Source: EIA, *Annual Energy Outlook 2019*.

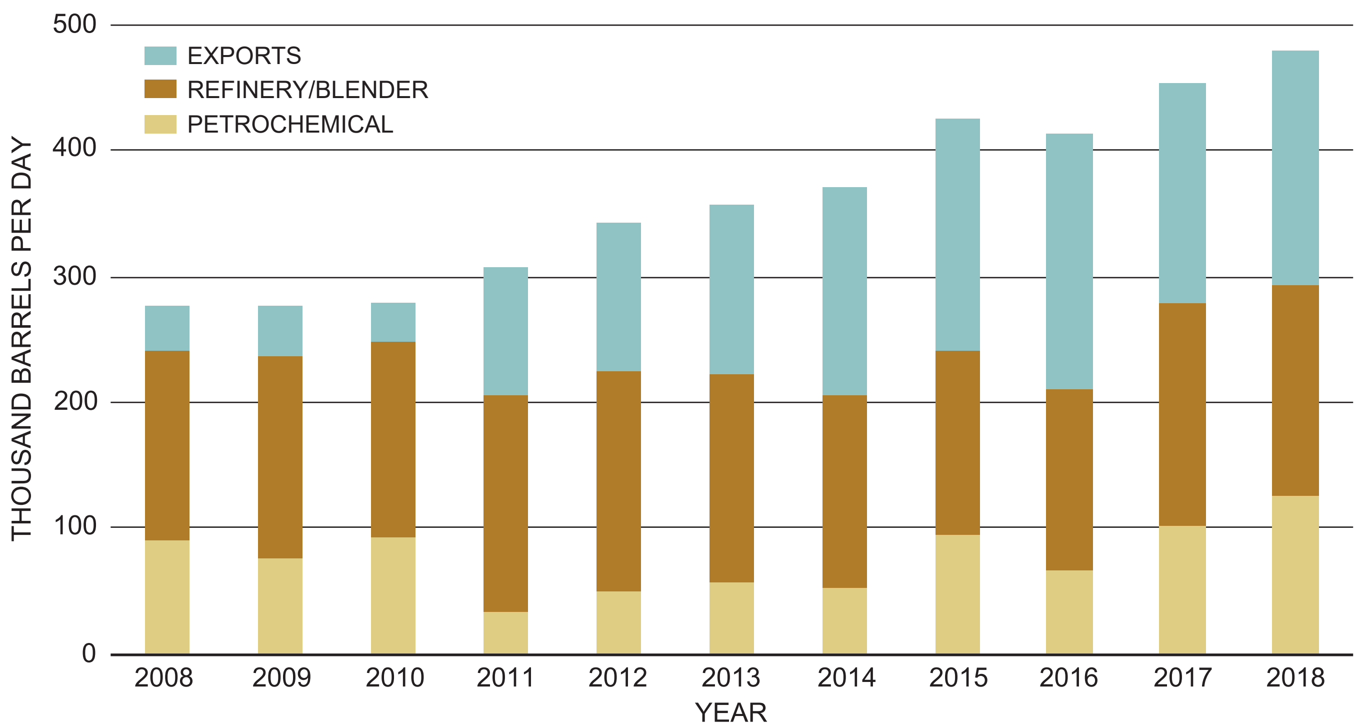
Figure 1-72. *U.S. Total Butane Production*

export gasoline to other markets where sulfur levels are not as stringent have more flexibility to use the stream in their blends.

A second major use of natural gasoline/pentane plus is for export to Canada for use as diluent for heavy crude oil. Diluent dilutes the heavier crude oil making it shippable by pipeline. The stream has attractive blending characteristics for Canadian heavy oil producers who need to lower the viscosity of their oil blend so that it can be shipped more easily via pipeline. The Cochin pipeline is currently in service from the U.S. Midwest to Hardisty in Alberta, Canada, bringing between 150 and 200 MMB/D of diluent for use in heavy oil blending.

Some natural gasoline/pentane plus is also exported to Latin America for diluent use or gasoline blending.

Natural gasoline/pentane plus can also be used as feedstock for olefin production, as long as the steam cracker is designed to process the material



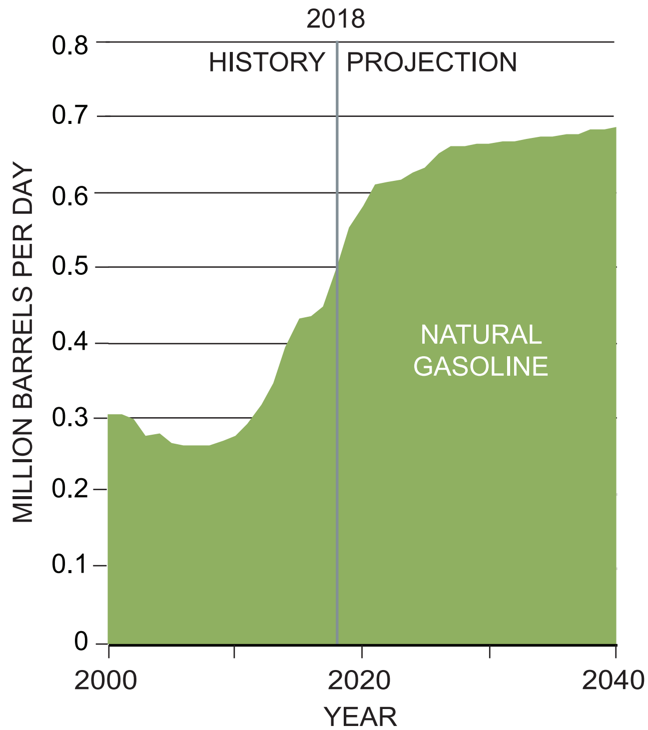
Source: EIA, Petroleum & Other Liquids data, and Argus Consulting Services.

Figure 1-73. *U.S. Natural Gasoline Disposition* and separate the byproducts efficiently. An ethylene plant designed to feed ethane or propane only cannot process natural gasoline pentane plus as it lacks sufficient equipment to separate the byproducts produced by the feedstock. Figure 1-73 shows the volumes of natural gasoline/pentane by use.

Domestic demand for natural gasoline is not expected to see significant growth in the future (Figure 1-74), and any growth in production is likely to make its way to export markets.

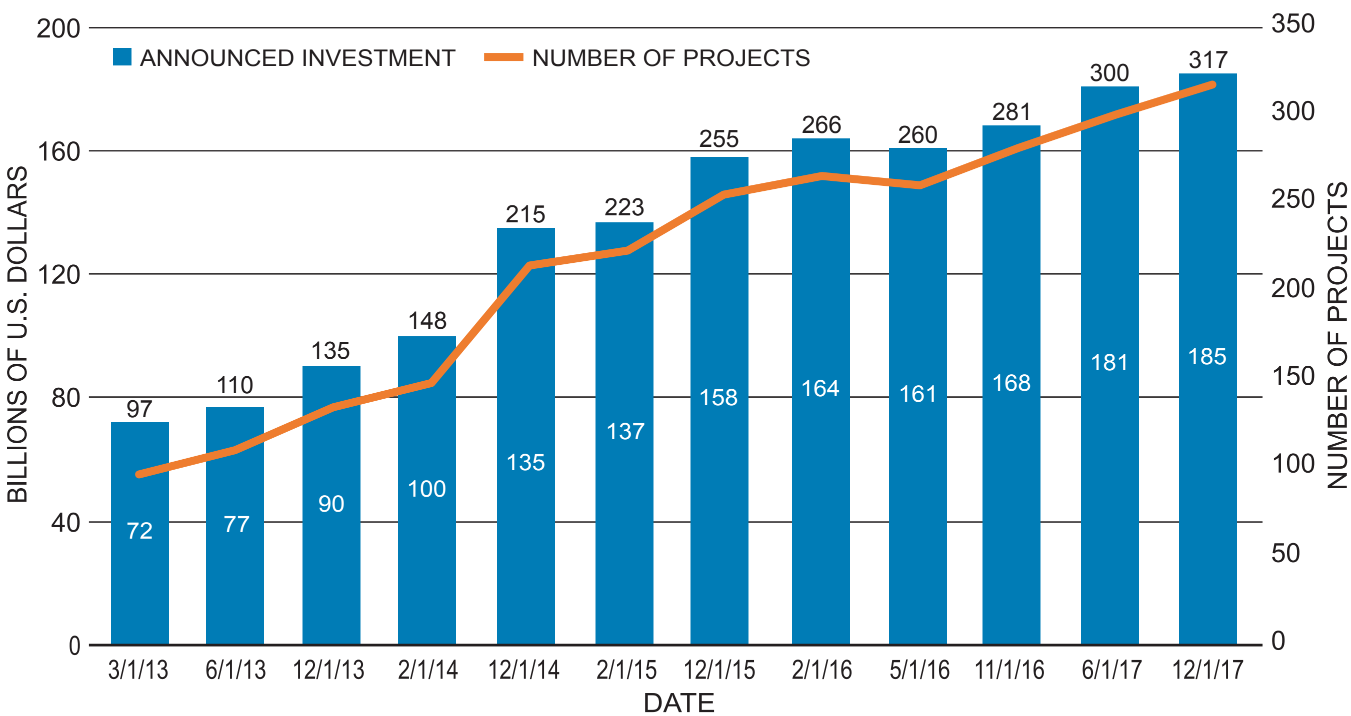
2. Petrochemicals

In the United States, the petrochemical industry has experienced an unprecedented revival since 2008. From its status as a mature and less competitive industry relative to other regions of the world, the increased availability of competitively priced feedstocks (natural gas, NGL, and to a lesser extent, crude oils) has resulted in renewed investment and competitiveness for the domestic industry. Figure 1-75 shows investments in new petrochemical plants reached over



Source: EIA, *Annual Energy Outlook 2019.*

Figure 1-74. *U.S. Natural Gasoline Production*



Source: American Chemistry Council, Press Release, September 11, 2018, "U.S. Chemical Industry Investment Linked to Shale Gas Reaches $200 Billion."

Figure 1-75. *Petrochemical Investments*

$200 billion by September 2018, with potentially more to come.

The U.S. Gulf Coast states of Texas and Louisiana have captured the majority of the investments, for the following reasons:

- Existing feedstock and product shipping logistics, including storage
- Availability of competitively priced natural gas
- Port facilities and waterways for exports of petrochemical products
- Feedstock availability
- Existing sites, where new capacity can be added with less new infrastructure.

The U.S. petrochemical industry is heavily concentrated in PADD 3. A few selected petrochemical product capacities are shown in Table 1-5.

U.S. ethylene production capacity is shown in Figure 1-76. Most of the capacity is in Texas or Louisiana.

Product	Total U.S. Production Capacity, 000 mt/yr	Total PADD 3 Production Capacity, 000 mt/yr	Percent of U.S. Capacity in PADD 3
Ethylene	33,216	31,818	96%
Styrene	5,022	5,022	100%
Polyethylene	19,012	18,019	95%
Ethylene Glycol	3,479	3,410	98%
U.S. Petrochemicals			**95+%**

Source: Argus Balances.

Table 1-5. *Selected Segments for the U.S. Petrochemical Industry, 2018*

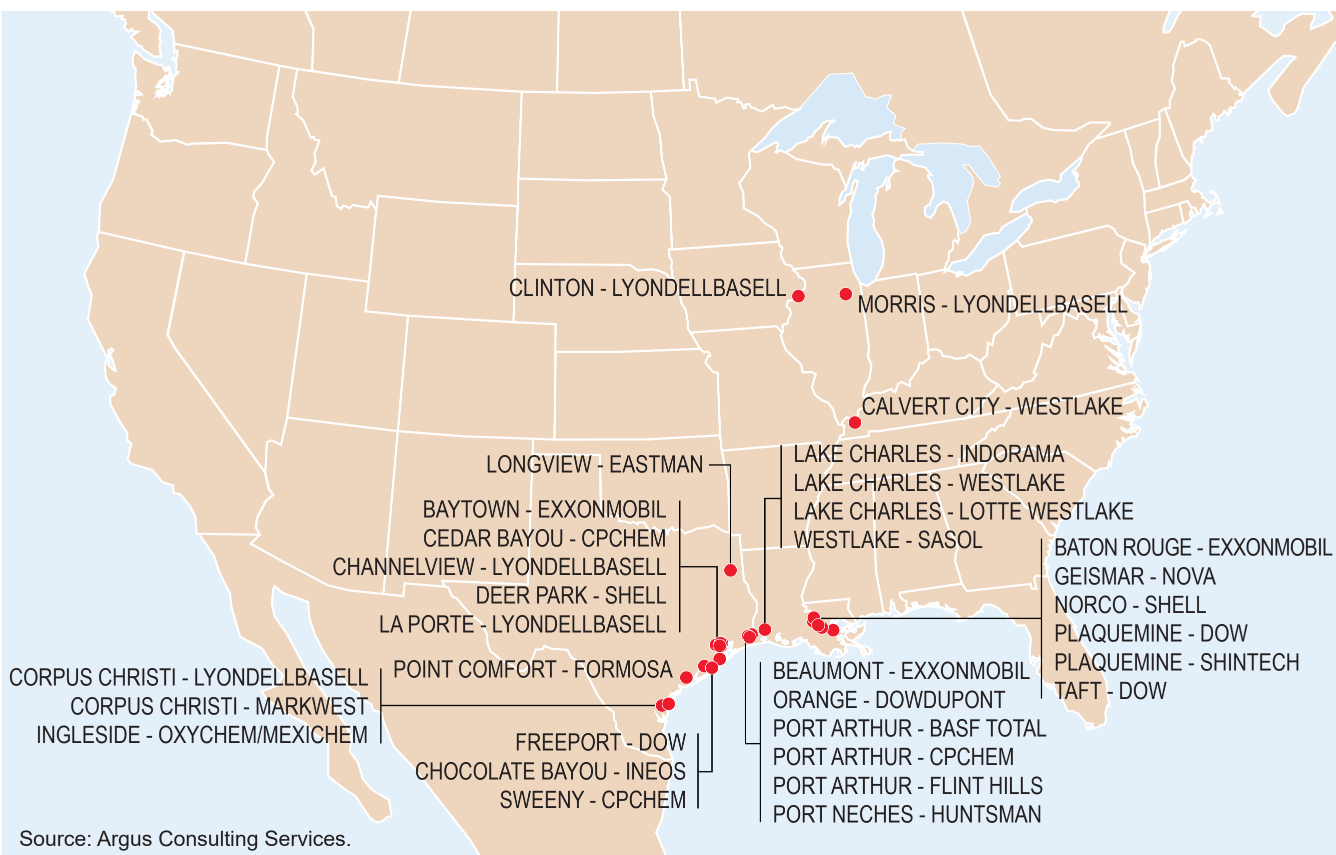


Figure 1-76. *U.S. Ethylene Crackers, 2019*

U.S. ethylene production capacity has grown by 21% since 2015 (data are in thousands of tonnes of capacity per year).

Of the total current U.S. capacity (2019) to produce ethylene, only 4% (1,398 thousand tonnes) is not located on the U.S. Gulf Coast (Clinton, IA; Morris, IL; and Calvert City, KY).

Of the new announced capacity expansions listed in Table 1-6, all are situated on the U.S. Gulf Coast except for the Shell project in Monaca, PA.

If all of the capacity comes online as expected, U.S. ethylene capacity will have increased by 47% from 2015 to 2022. Future projects have been proposed and are being evaluated to determine if they will move forward. The growth of ethylene capacity has outpaced the growth of the polymer demand, and new ethylene export facilities will be needed until the downstream units are built.

At the end of 2015, it is estimated that the United States had some 15.7 million tonnes of polyethylene capacity. As noted previously, the capacity is highly concentrated on the U.S. Gulf Coast. For future expansions shown in Table 1-7, new polyethylene capacity is also concentrated at the U.S. Gulf Coast. The exception is the new petrochemical complex being developed by Shell in Monaca, PA.

Capacity for polyethylene production is expected to grow by more than 60% by 2022 versus the 2015 base capacity.

Conversely, many of the consumers of commodity petrochemicals/plastics (converters) are more concentrated in the Midwest and Northeast regions of the United States. Large converters of commodity plastic pellets (polyethylene, polypropylene, polystyrene, and polyester) have facilities away from the Gulf Coast, closer to their customers. These converters purchase pellets via rail hopper car or truck load and produce food containers, plastic bottles, building materials, and disposables such as plates or cutlery. More than 85% of plastic pellets going to these converters are shipped by rail.

G. Carbon-Constrained Scenarios

Future demand for oil and natural gas would be impacted if the United Stated adopted a national policy to limit carbon emissions. This section considers how energy demand projections could change under three carbon-constrained policy scenarios. These scenarios do not represent a specific recommendation for future domestic policy. Instead, they were selected to provide a framework for considering how oil and natural gas demand could change under policies of varying stringency and scope.

This includes modeling analysis of:

1. A suite of ambitious environmental and energy goals as outlined in the SDS released by IEA in its 2018 World Energy Outlook[35]

35 International Energy Agency, World Energy Outlook 2018, https://www.iea.org/weo2018/.

Company	Location	2015	2016	2017	2018	2019	2020	2021	2022
Bayport Polymers	Port Arthur, TX	0	0	0	0	0	0	1,000	1,000
Dow	Freeport, TX						500	500	500
Formosa Plastics	Point Comfort, LA	0	0	0	0	300	1,200	1,200	1,200
Lotte Chemical Westlake	Lake Charles, LA	0	0	0	0	600	1,000	1,000	1,000
Sasol	Westlake, LA	0	0	0	0	750	1,500	1,500	1,500
Shell Chemicals	Monaco, PA	0	0	0	0	0	0	800	1,600
Shintech	Plaquemine, LA	0	0	0	0	250	500	500	500
Grand Total		**0**	**0**	**0**	**0**	**1,900**	**4,700**	**6,500**	**7,300**

Source: Argus Consulting Services.

Table 1-6. *Announced Ethylene Production Additions (Thousands of Tonnes)*

2. A $50/tonne economy-wide carbon tax starting in 2020[36]
3. A $73/tonne economy-wide carbon tax starting in 2020.[37]

The three modeling scenarios project U.S. economy-wide CO_2 emission reductions that range from 35% to 72% below 2005 levels in 2040.[38]

36 Larsen, John et al. *Energy and Environmental Implications of a Carbon Tax in the United States*. Prepared by Rhodium Group for Columbia SIPA Center on Global Energy Policy, July 2018, https://energypolicy.columbia.edu/sites/default/files/pictures/CGEP_Energy_Environmental_Impacts_CarbonTax_FINAL.pdf, p. 6.

37 Larsen, John et al., p. 15.

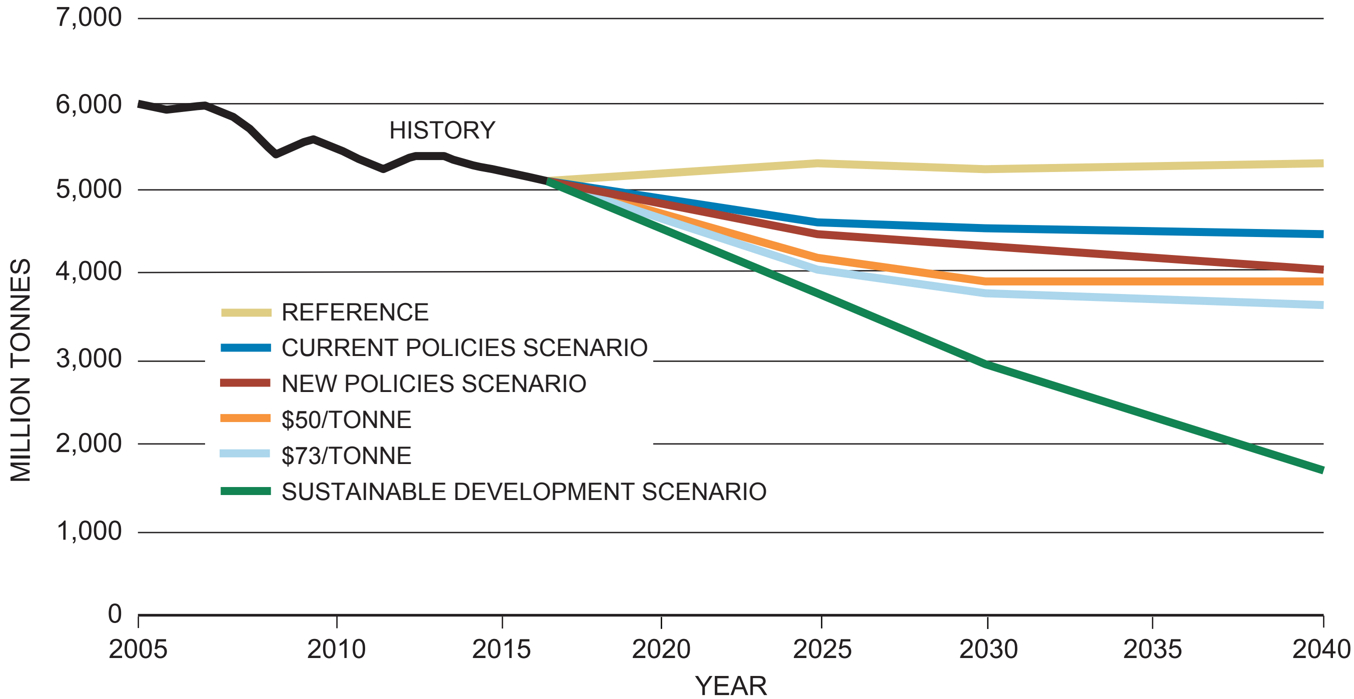
38 Historical CO_2 emissions are based on U.S. Energy Information Administration, February 2019, Monthly Energy Review.

It is important to note that these modeling analyses are not intended to give precise predictions of the future but outline a range of possible CO_2 reduction outcomes. The analyses contain many assumptions, including federal and state policies, fuel costs, technology costs, cost and availability of energy efficiency, and energy demand. Furthermore, it is important to note that models have historically failed to accurately capture the price and performance of future technologies. It is therefore unlikely that the scenarios explored here capture the full range and costs of technologies that would be competing in a low-carbon economy in 2040. Expected CO_2 emissions reductions for the various scenarios analyzed are shown in Figure 1-77.

Company	Location	Capacity (thousand tonnes)	Grade	Start-up	Current Status
Dow Chemical	Freeport, TX	400	LLDPE	17-Sep	Operational
Chevron Phillips	Old Ocean, TX	1000	HDPE/LLDPE	17-Sep	Operational
Ineos/Sasol	La Porte, TX	470	HDPE	4Q 2017	Operational
ExxonMobil	Mont Belvieu, TX	1300	HDPE/LLDPE	4Q 2017	Operational
Dow Chemical	Plaquemine, LA	400	LDPE	1Q 2018	Operational
Dow Chemical	Taft, LA	125	HDPE	4Q 2018	Operational
Dow Chemical	Freeport, TX	320	Elastomers	4Q 2018	Operational
Sasol	Lake Charles, LA	450	LLDPE	1Q 2019	Operational
ExxonMobil	Beaumont, TX	650	LLDPE	4Q 2019	Complete
Formosa Plastics	Point Comfort, TX	400	HDPE/LDPE/LLDPE	3Q 2019	Mech Complete
LyondellBasell	La Porte, TX	500	HDPE	4Q 2019	Mech Complete
Sasol	Lake Charles, LA	420	LDPE	4Q 2019	Mech Complete
Formosa Plastics	Point Comfort, TX	400	LDPE	4Q 2019	Construction
Shell Chemical	Monaca, PA	1100	HDPE	2021	Construction
Shell Chemical	Monaca, PA	500	LLDPE	2021	Construction
Dow Chemical	Freeport, TX	600	LLDPE	2022	Announced
Bayport Poly	Bayport, TX	650	HDPE	2022	Construction
ExxonMobil/Sabic	Corpus Christi, TX	600	HDPE/LLDPE	2022	Construction
ExxonMobil/Sabic	Corpus Christi, TX	650	HDPE	2022	Construction
Total supply additions		**10,935**	**All**	**2017-2022**	

Source: Argus Consulting Services.

Table 1-7. *Recent and Future Polyethylene Capacity Expansions (Millions of Tonnes per Year)*



Sources: International Energy Agency, *World Energy Outlook*; U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Emissions and Sinks 1990-2017*; and Rhodium Group and Columbia University's Center on Global Energy Policy, 2018.

Figure 1-77. *U.S. CO_2 Emissions Reduced by 15% since 2007*

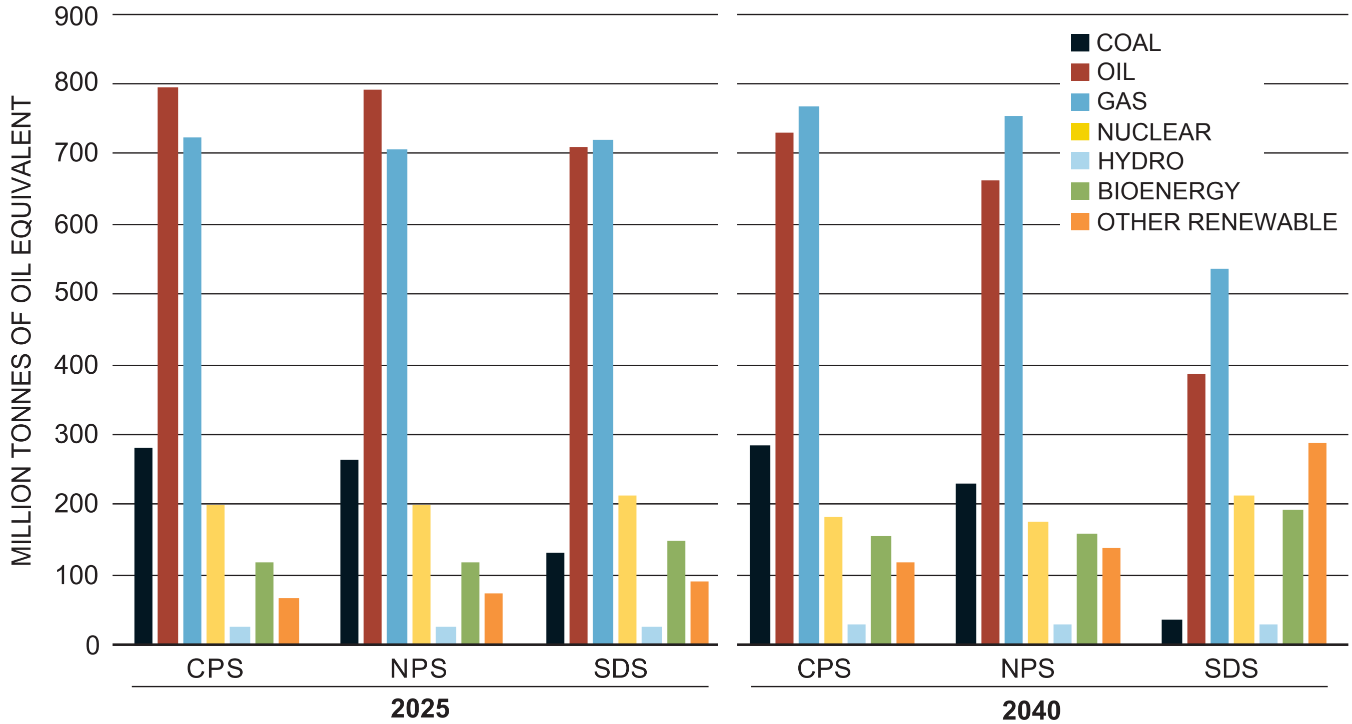
1. U.S. Oil and Natural Gas Demand Under the IEA's SDS

The United States has reduced CO_2 emissions by 15% since 2007 (Figure 1-77). Natural gas has played a key role in this reduction. Going forward, oil and natural gas will continue to provide a large percentage of primary energy consumption (Figure 1-78). The IEA WEO 2018 includes three modeling scenarios:

1. The Current Policies Scenario (CPS), which captures global policies as of mid-2018 and assumes laws and regulations do not change over time.
2. The New Policies Scenario (NPS), which reflects government policies in place as of mid-2018 as well as some announced policies, including the Nationally Determined Contributions countries agreed to under the Paris Agreement.
3. The Sustainable Development Scenario, which assumes a major transformation of the global energy system to achieve three policy goals:
    a. Universal access to modern energy by 2030
    b. Dramatic reductions in health impacts due to energy-related air pollution.
    c. Global compliance with the goals laid out in the Paris Agreement. This assumes global greenhouse gas emissions peak by 2020 and then decline rapidly, with net-zero emissions achieved by 2070.

To meet the ambitious policy goals laid out in the SDS, the analysis projects significant fuel consumption changes across all sectors of the economy. This differs from the carbon tax scenarios, where consumption changes are predicted to occur primarily in the power sector. By 2040, the SDS projects coal demand is reduced 84% to 87%, oil demand is reduced 42% to 47%, and natural gas demand is reduced 29% to 30%, compared to the NPS and CPS models. This demand is replaced by increases in renewable energy, bioenergy, and energy efficiency. Expected energy demand for the various scenarios are shown in Figure 1-80.

While the power sector is not the only significant source of emissions reductions in the SDS, it



Note: CPS = Current Policies Scenario, NPS = New Policies Scenario, SDS = Sustainable Development Scenario.
Source: International Energy Agency, *World Energy Outlook 2018.*

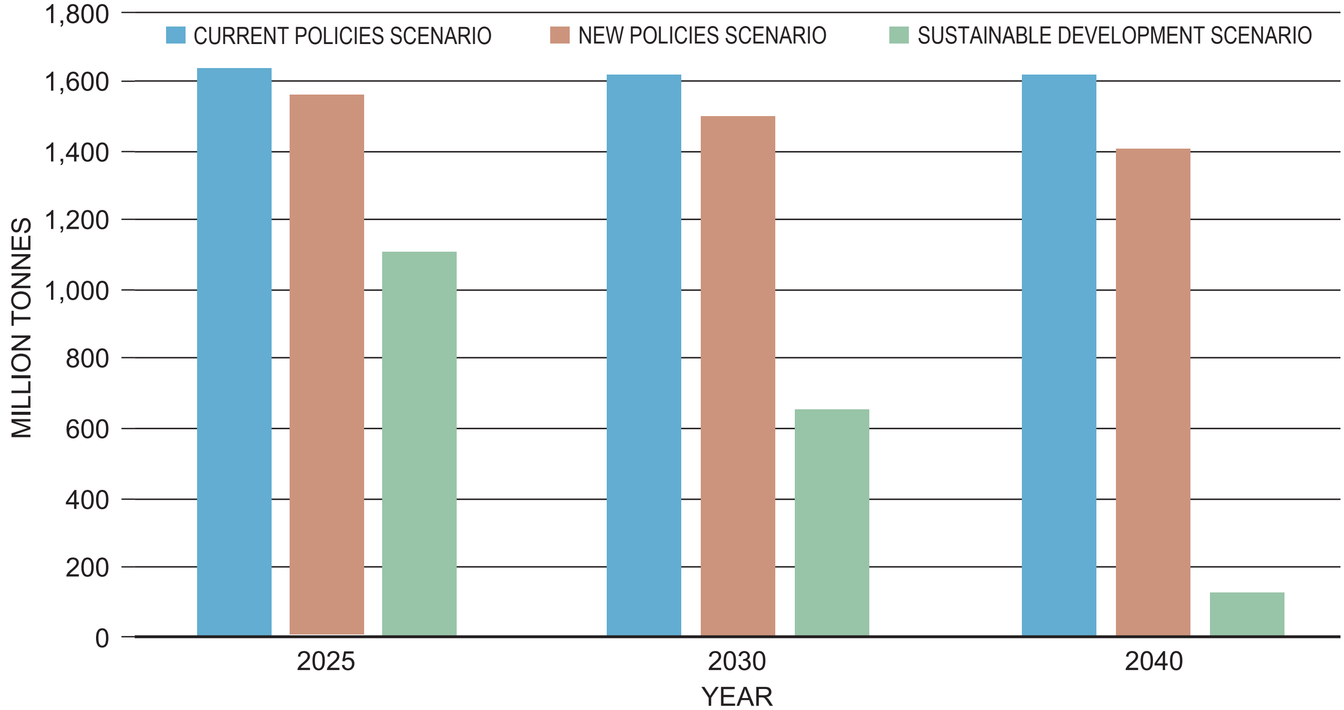
Figure 1-78. *Oil and Natural Gas Remain the Top Two Sources of Primary Energy in all IEA Scenarios*

plays a major role in meeting the scenario's energy and environmental goals. In 2040, power sector emissions fall 92% in the SDS, compared to emissions in the CPS (Figure 1-79). These reductions are driven by changes in the generation mix. Coal generation, which comprises 23% of total generation in 2040 in the CPS, falls to 2% in the SDS. Natural gas utilization ramps up in the near term, as lower-emitting natural gas generation replaces higher-emitting coal generation. In 2025, natural gas comprises 34% of total generation in the CPS and 40% in the SDS. However, by 2040, renewable generation increases substantially under the SDS and displaces some of the gas-fired generation. Figure 1-80 shows that in 2040, renewables provide 64% of total generation and natural gas provides 16% of total generation in the SDS. This includes natural gas growth with carbon capture, use, and storage (CCUS).

Finding: Even in scenarios designed to meet climate change targets, the largest energy sources continue to be oil and natural gas through at least 2040 to provide reliable and affordable energy.

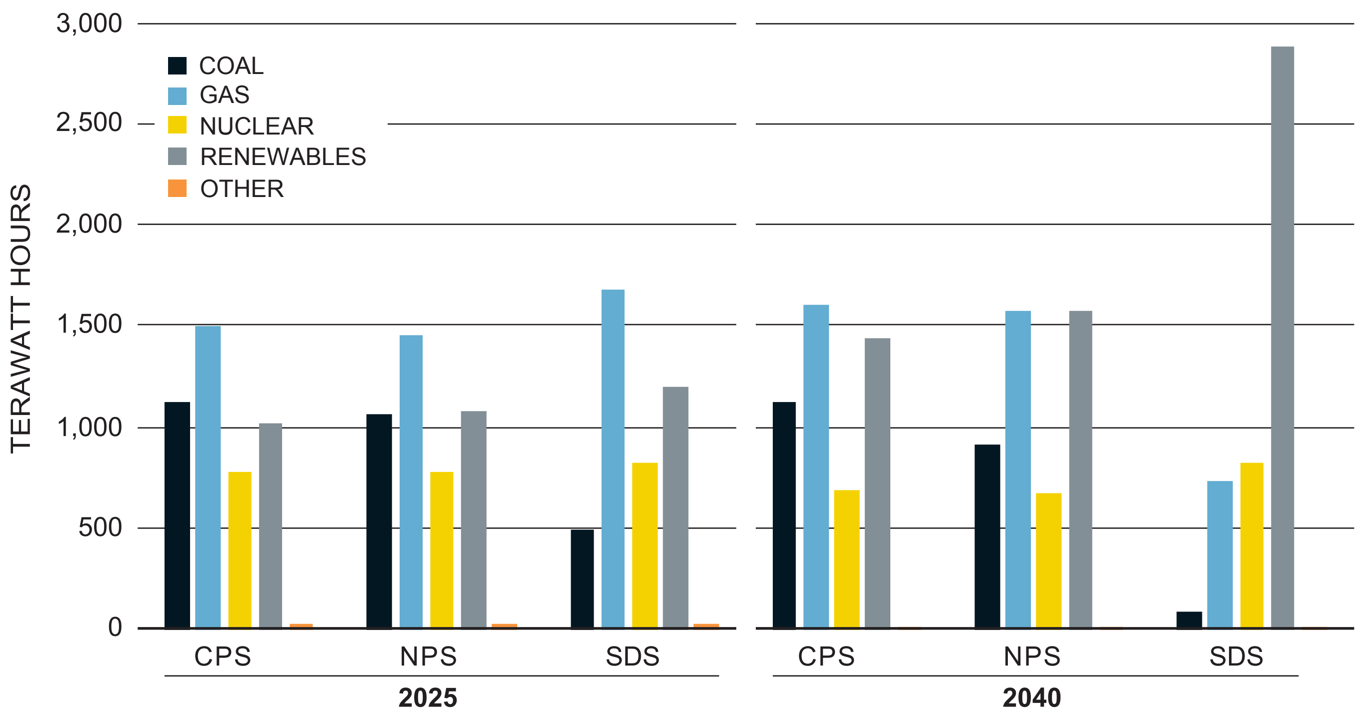
To reach the energy and environmental goals underpinning the SDS, changes in oil and natural gas demand are also projected in other sectors of the economy. In the transportation sector shown in Figure 1-81, CO_2 emissions in the SDS fall compared to both the CPS and NPS. By 2040, CO_2 emissions from the transportation sector are projected to be 56% to 61% lower. And while oil remains the dominant transportation fuel throughout all scenarios out to 2040, its use is cut by more than half in 2040 in the SDS compared to the CPS and NPS. This is achieved by increasing reliance on alternative transportation fuels, such as biofuels and electrification as shown in Figure 1-82.

Changes in primary energy demand in the buildings and industrial sectors also contribute to the policy goals laid out in the SDS. In the SDS, natural gas demand in the buildings sector falls



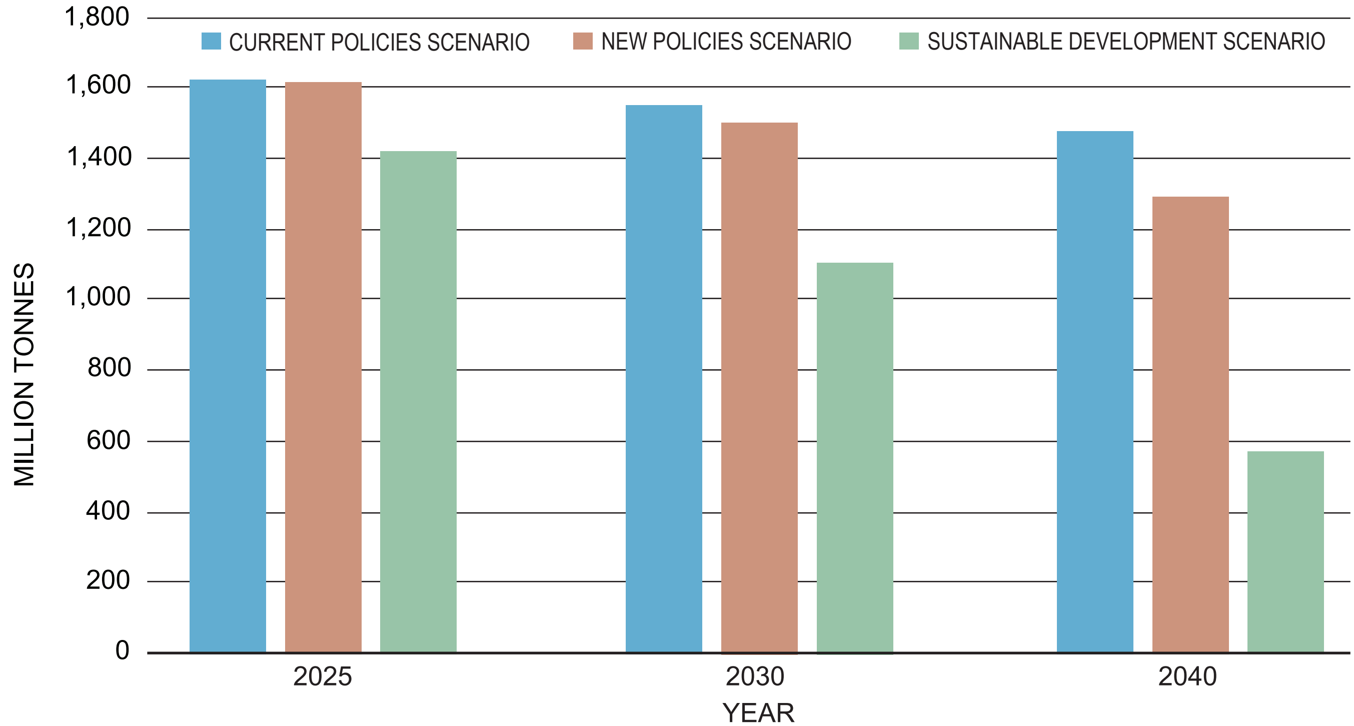
Source: International Energy Agency, *World Energy Outlook 2018.*

Figure 1-79. *U.S. CO_2 Emissions: Power Sector, 2025, 2030, and 2040*



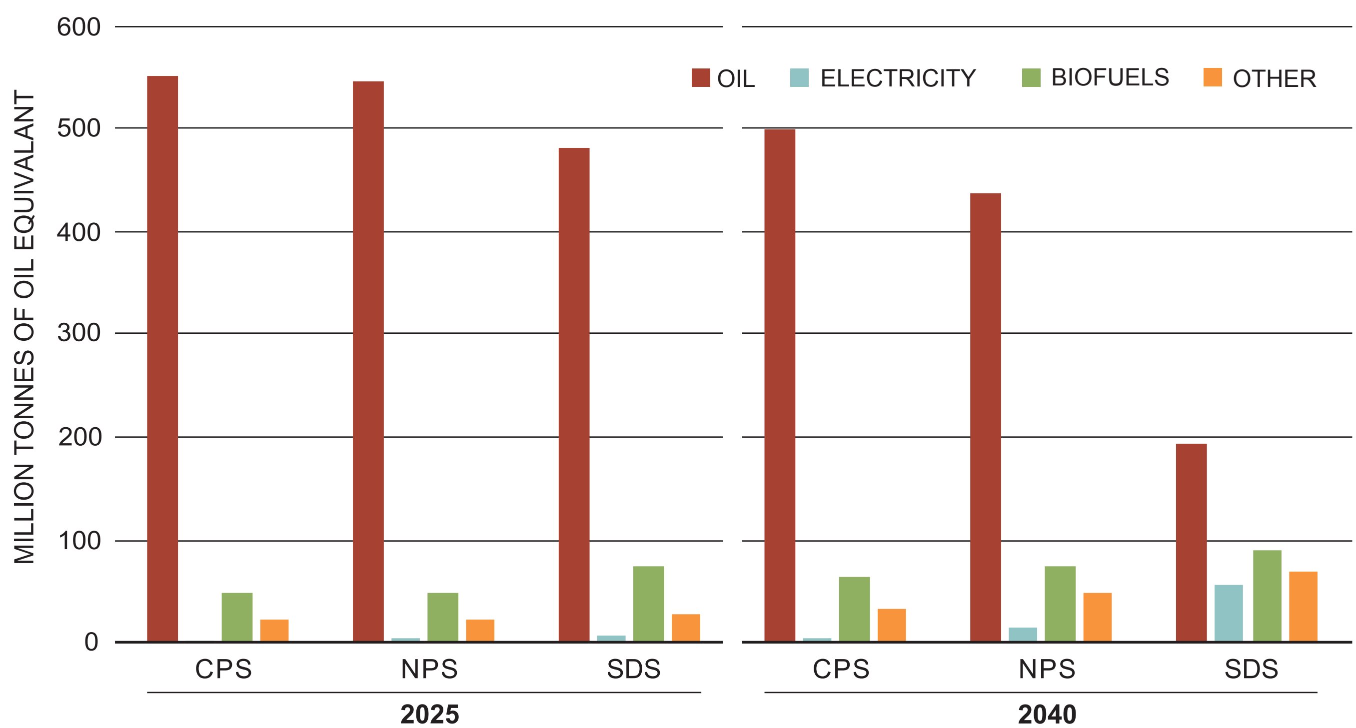
Note: CPS = Current Policies Scenario, NPS = New Policies Scenario, SDS = Sustainable Development Scenario.
Source: International Energy Agency, *World Energy Outlook 2018.*

Figure 1-80. *U.S. Electricity Generation, 2025 and 2040*



Source: International Energy Agency, *World Energy Outlook 2018*.

Figure 1-81. *U.S. CO_2 Emissions: Transportation Sector, 2025, 2030, and 2040*



Note: CPS = Current Policies Scenario, NPS = New Policies Scenario, SDS = Sustainable Development Scenario.

Figure 1-82. *U.S. Transportation Fuel Mix, 2025 and 2040*

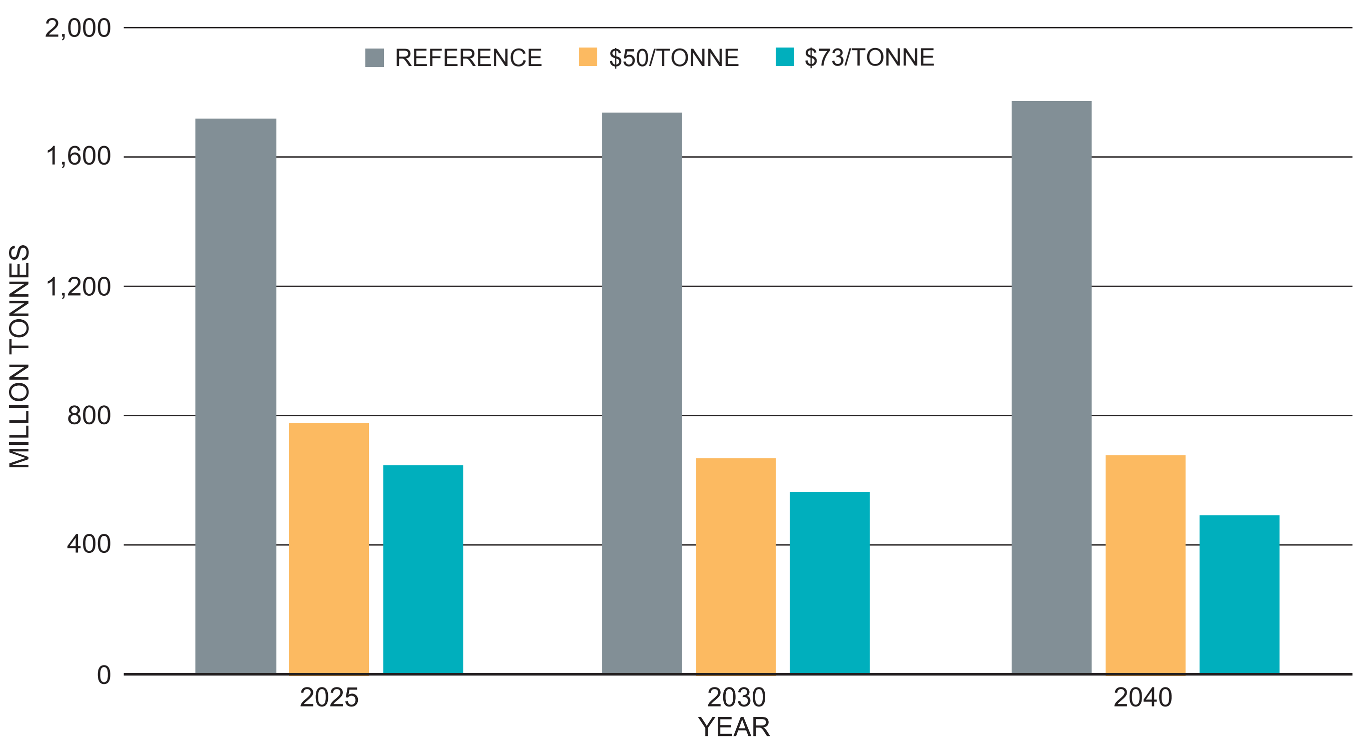
29% to 34% in 2040 compared to the other scenarios. This is primarily due to increased energy efficiency investments and electrification, including a switch from natural gas heating to electric heat pumps. And in the industrial sector, natural gas demand falls 21% to 24% in 2040 compared to the other scenarios. This is also attributed to increases in energy efficiency and electrification, including electrification of low-heat industrial processes.

2. U.S. Oil and Natural Gas Demand in the Carbon Tax Scenarios

In July 2018, Rhodium Group and Columbia University's Center on Global Energy Policy released the report, *Energy and Environmental Implications of a Carbon Tax in the United States*. The report provides publicly available carbon tax modeling analysis at varying tax levels. We look at two of the report's economy-wide domestic carbon tax scenarios as well as projection of business-as-usual assumptions (Figure 1-83). This includes:

1. A \$50/tonne carbon dioxide equivalent (CO_2e) tax that rises at an approximately 2% real rate annually beginning in 2020
2. A \$73/tonne CO_2e tax that rises at an approximately 1.5% real rate annually beginning in 2020
3. A reference case, which represents a business-as-usual projection primarily based on reference case projections from the EIA's 2017 Annual Energy Outlook.

The analysis uses the economy-wide energy-economic model RHG-NEMS, a version of the National Energy Modeling System (NEMS) operated by Rhodium Group. The scenarios assume the tax applies to domestic CO_2 emissions that occur from the combustion or consumption of fossil fuels as well as methane emissions that occur during the production of oil and natural gas. These emissions represent about 81% of U.S. gross greenhouse gas emissions in 2015. The tax is applied in the model to each fuel just after the wholesale transaction



Source: Rhodium Group and Columbia University's Center on Global Energy Policy, 2018.

Figure 1-83. *U.S. Power Sector CO_2 Emissions* occurs. For imported fuels, the tax applies after the fuel is imported.[39]

Both the $50/tonne and the $73/tonne scenarios drive economy-wide emission reductions primarily by incentivizing reductions in the power sector. In 2040, power sector CO_2 emissions in the tax scenarios are down 1,095 to 1,283 million tonnes compared to a business-as-usual projection, representing about 80% of total 2040 emission reductions.

The reductions in power sector emissions are driven by changes in the projected generation mix shown in Figures 1-84 and 1-85. The tax increases the cost of generation for emitting fuels, and therefore, their competitiveness in wholesale power markets. Coal, which has approximately double the CO_2 emissions as natural gas,[40] is the primary fuel impacted in these scenarios. Coal generation is projected to decrease by 97% to 99% in 2040 compared to a business-as-usual projection. The coal-fired generation is replaced by lower-emitting generating sources, including natural gas; wind, solar, and hydro; and nuclear. This includes a small amount of coal and natural gas with CCUS. Under the assumed technology and fuel costs, there is no CCUS capacity added in the business-as-usual projection. However, CCUS becomes economic in the tax scenarios. In the $50/tonne scenario, there is 7 GW of natural gas with CCS and 2 GW of coal with CCUS projected in 2040. In the $73/tonne scenario, there is 55 GW of natural gas with CCUS and 1 GW of coal with CCUS projected in 2040.

Natural gas generation and capacity is projected to be higher under the tax scenarios than under business-as-usual assumptions. In the absence of a carbon tax, natural gas generation is projected to comprise 28% of total generation in 2040. However, with a carbon tax in place, natural gas generation is projected to comprise 42% of total generation in the $50/tonne scenario. The $73/tonne scenario incentivizes relatively more renewable generation and capacity into the mix; however, natural gas generation still comprises 38% of total generation in 2040. The projected generation mix reflects underlying assumptions about the fuels, including the emissions profiles of the sources and fuel costs. This analysis is based on AEO 2017, which has Reference Case Henry Hub prices of $4.25 to $5.00/MMBTU. If natural gas prices are higher than assumed, there would likely be less natural gas generation in the mix.

The analysis projects fewer changes in demand for oil and natural gas in other sectors of the economy, including in the transportation, industrial, and buildings sectors. At the tax levels modeled, there are not as many readily available and economically competitive near- and medium-term substitutions for oil and natural gas in these sectors, nor does the model project substantial changes in consumer preferences. For example, the $50/tonne scenario results in a $0.44 increase in retail gasoline prices in 2020. In the $73/tonne scenario gasoline prices rise $0.64. As a result, demand for gasoline-powered transportation is only minimally impacted and transportation-related CO_2 emissions are projected to fall only 2% to 4% in 2040 compared to a business-as-usual scenario (Figure 1-86). The model projects demand for distillate fuels[41] to be similarly unchanged in the tax scenarios.

3. Carbon-Constrained Impacts per Sector

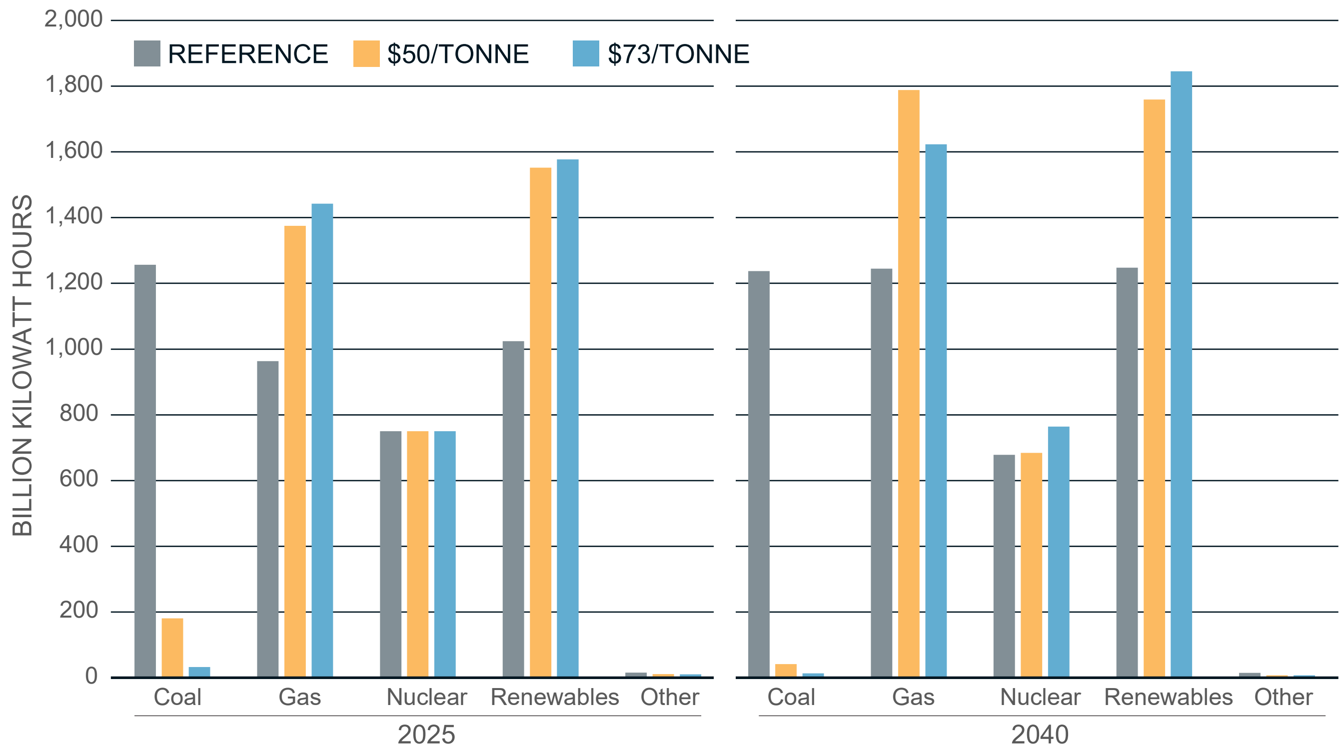
a. Electricity Sector

In all of the carbon-constrained modeling scenarios examined for this report, natural gas continues to play an important role in a low-carbon electricity generation mix—both in near-term and longer-term projections. This includes providing an immediate substitution for higher-emitting fuels and in later years complementing high levels of variable renewable energy sources.

39 This analysis assumes that the carbon tax revenue is recycled back into the U.S. economy and is not used to support specific policies that could accelerate emission reductions, such as investing in energy efficiency programs or clean energy research and development.

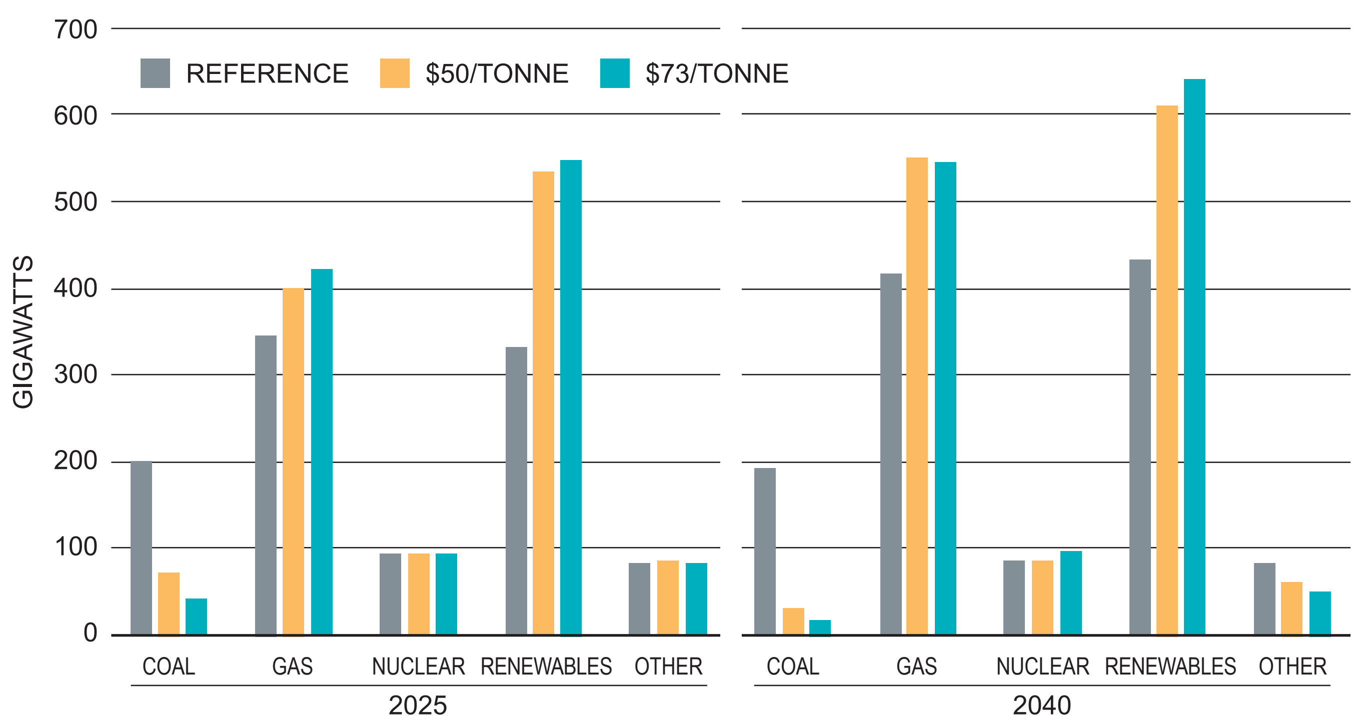
40 U.S. Energy Information Administration, Frequently Asked Questions, "How much carbon dioxide is produced when different fuels are burned?" https://www.eia.gov/tools/faqs/faq.php?id=73&t=11 (accessed October 24, 2019).

41 A general classification for one of the petroleum fractions produced in conventional distillation operations. It includes diesel fuels and fuel oils. Products known as No. 1, No. 2, and No. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. Products known as No. 1, No. 2, and No. 4 fuel oils are used primarily for space heating and electric power generation.



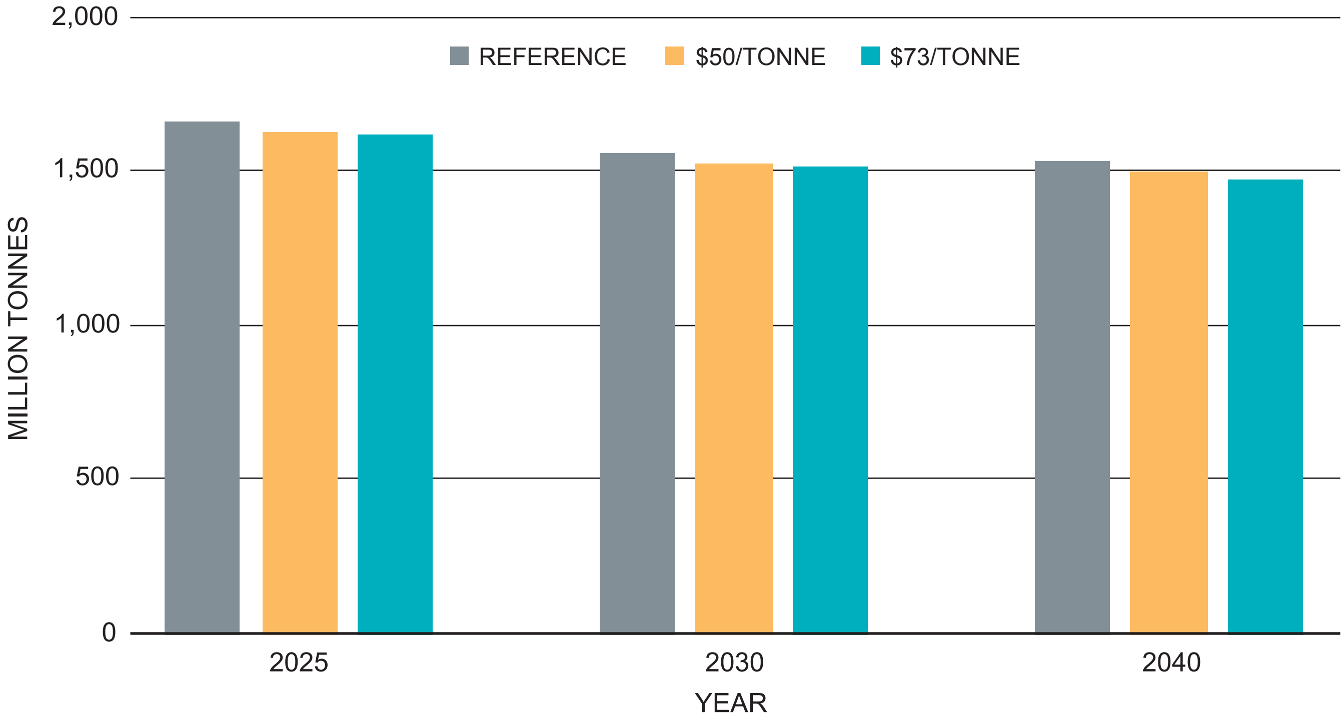
Source: Rhodium Group and Columbia University's Center on Global Energy Policy, 2018.

Figure 1-84. *U.S. Electricity Generation Projections, 2025 and 2040*



Source: Rhodium Group and Columbia University's Center on Global Energy Policy, 2018.

Figure 1-85. *U.S. Net Summer Capacity Projections, 2025 and 2040*



Source: Rhodium Group and Columbia University's Center on Global Energy Policy, 2018.

Figure 1-86. *U.S. CO_2 Transportation Emissions Projections, 2025, 2030, and 2040*

Natural gas generation has a lower emissions profile than coal-fired generation. Increased utilization of existing and new gas-fired power plants provides a near- and mid-term lower-carbon substitution opportunity in the power sector. Natural gas and renewables are projected to ramp up in 2025 under the three carbon-constrained scenarios reviewed for this section.

In the SDS, natural gas continues to play a critical, although more limited, role in the national generation mix as emission reduction requirements tighten out toward mid-century. Natural gas generation, including natural gas with CCS, is still projected to comprise about a quarter of the 2040 generation mix.

These natural gas plants help provide the firm low-carbon generation needed to complement variable renewable generation in a high-renewables grid. These technologies complement variable renewable sources, such as wind and solar, and ensure that real-time demand can be met in all seasons of the year and over long durations, including when variable resources are not available. If the United States were to fully decarbonize the electricity sector, natural gas generators would need to be equipped with CCS technology.

b. Transportation Sector

The carbon-constrained scenarios described previously highlight the varying impact of different policies and technology assumptions on fuel consumption in the transportation sector. In the carbon tax scenarios reviewed, the tax does little to reduce demand for oil-based transportation fuels. And, as a result, the tax has limited impact on transportation sector CO_2 emissions. The tax levels modeled were not high enough to immediately reduce consumer's inelastic demand for transportation or incent longer-term demand for lower-carbon vehicles or transportation modes.[42] Even if the tax were sufficiently high to impact consumer purchasing choices, vehicle fleet turnover is relatively slow. A 2019 paper published in the

42 Larsen, John et al., p. 20.

journal *Environmental Research Letters* found that the average vehicle lifetime in the United States is 16.6 years. The authors project that if alternative vehicles, such as electric vehicles, suddenly comprised 100% of new vehicle sales, it would still take 19.6 years for the new technology to account for 90% of the on-road fleet.[43]

The SDS, however, does project a pathway to achieving significant cuts to transportation sector CO_2 emissions. This is achieved by substituting traditional oil-based fuels with alternative fuels, such as electrification and biofuels. In 2040, oil demand in the transportation sector is projected to decrease 56% to 61% compared to the Current and New Policies Scenarios.

c. Other Sectors

Energy demand in other sectors of the economy, including the buildings and industrial sectors, are also impacted to varying degrees by the different policies modeled. As with the transportation sector, these sectors are not as responsive to the carbon tax as the power sector. However, the SDS incents more substantial changes in fuel consumption in these sectors, primarily through increases in electrification and energy efficiency.

IV. SUMMARY OF FINDINGS

Finding: U.S. growth in liquids production since 2008 (crude oil and natural gas liquids, NGLs) is unprecedented in the history of the industry. The United States is once again the largest producer in the world of crude oil and NGLs.

Finding: U.S. natural gas production began an upward climb in 2006 and by 2012 the United States became the largest natural gas producer in the world when it overtook Russia.

Finding: The United States has become the largest producer of both oil and natural gas in the world.

Finding: The U.S. oil and natural gas story is not just about volume growth—but geography as production grew in rejuvenated and new areas across the country.

43 Keith, David R. et al., "Vehicle fleet turnover and the future of fuel economy," Environmental Research Letters 14 021001, February 2019, https://doi.org/10.1088/1748-9326/aaf4d2 (accessed at https://iopscience.iop.org/article/10.1088/1748-9326/aaf4d2/pdf).

Finding: Long-term projections of U.S. crude oil production show a wide range of outcomes. The variations reflect diverse assumptions about price, technology, policy, and resources.

Finding: Access to export markets is a critical assumption in outlooks showing growth in U.S. crude oil, natural gas, and NGLs production.

Finding: The Permian Basin in West Texas and Southeast New Mexico is the most important source of recent and projected crude oil production growth.

Finding: Long-term projections of U.S. natural gas production show a range of outcomes. The variations reflect diverse assumptions about price, technology, policy, and resources.

Finding: The Appalachian Basin is the most important source of U.S. natural gas supply growth to 2040 according to the outlooks provided to this study.

Finding: Assuming minimal change in the current capacity, processing configurations, and utilization of U.S. refineries, net exports of refined products will increase.

Finding: Due to the increase in U.S. crude oil production, crude oil imports have declined but have not been completely displaced. Despite domestic crude oil production growth forecasts, imports will continue in the United States due to (1) quality requirements of U.S. refineries and (2) locational discrepancies between production regions and certain refining regions.

Finding: U.S. liquids consumption (refined products and biofuels) is projected to decline between 2017 and 2040 under most scenarios. Demand reduction is most prominent in the gasoline market.

Finding: U.S. natural gas demand is projected to increase through 2040 with growth driven primarily by the electric power sector.

Finding: Increased natural gas use replacing coal to generate electricity has been the single largest contributor to reducing U.S. CO_2 emissions—by 15% since 2005.

Finding: Even in scenarios designed to meet climate change targets, the largest energy sources continue to be oil and natural gas through at least 2040 to provide reliable and affordable energy.