DYNAMIC DELIVERY

America's Evolving Oil and Natural Gas Transportation Infrastructure

CHAPTER TWO – INFRASTRUCTURE RESILIENCY, MAPPING, AND ANALYSIS

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INFRASTRUCTURE RESILIENCY, MAPPING, AND ANALYSIS

I. INTRODUCTION

The United States has transformed from a net energy importer to a country on the verge of becoming a net exporter as a result of the rapid growth in oil and natural gas production from shale formations. Much has been written about the country's growing production of oil and natural gas, but less attention has been paid to an equally important component: the role that energy infrastructure has played in the United States' rise in the global energy market.

This chapter provides an overview of the history and current state of the United States oil and natural gas transportation infrastructure, and describes the environmental and economic value of the multifaceted, nationwide system that ensures crude oil, refined fuels, natural gas, and natural gas liquids are transported from producing areas to consumers. This chapter also describes the physical interdependencies between various energy markets, the historical adaptability and resiliency of the current infrastructure, the existing and potential infrastructure constraints, and opportunities for industry, government, and regulatory agencies to sustain and grow the nation's oil and natural gas infrastructure.

As mature oil and natural gas-producing areas rapidly grew and new producing areas developed, supply locations geographically shifted, requiring significant investment in infrastructure to realign and expand transportation. The level of investment in oil and natural gas transportation infrastructure, which is predominantly pipelines, has increased over time. In the early years of shale development, production growth could take advantage of legacy pipeline infrastructure that had been in place for decades. Where existing pipeline capacity was inadequate, other modes of transportation, such as rail, trucks, and marine, were deployed. When production growth exceeded previous record peaks in the key shale basins and exceeded the capacity of existing and repurposed legacy infrastructure, new infrastructure was needed. Now, most increases in production require new greenfield pipelines in new rights-of-way and new export facilities.

The types of infrastructure needed to support growing crude oil, refined products, natural gas, and natural gas liquid (NGL) production have changed over the past decade. During the initial shale production growth, there was enough domestic end-use demand to absorb the incremental output. More U.S. crude oil moved to domestic refineries, reducing imports, and increasing capacity utilization. Much of the incremental gasoline and diesel output increased U.S. exports to overseas markets. Growing volumes of natural gas production were consumed by the U.S. power and industrial sectors as lower natural gas prices provided the economic incentive to use increasing domestic supplies, displacing other fuels such as coal. U.S. natural gas production now supports an expanding exports industry. Growth in NGL production drove down prices, providing a feedstock price advantage attracting investments for new domestic petrochemical plants and expansions to existing plants.

Domestic production growth is substantial enough to meet domestic demand and supply overseas markets. The flow of energy commodities to export terminals, mostly along the Gulf Coast, has required new pipelines to access port facilities and, most importantly, new and repurposed infrastructure to prepare and load U.S. energy commodities for export on ships bound for the global marketplace. This includes liquefaction facilities for natural gas, product chillers for propane, and extensive tankage to stage export cargoes and docks. The preponderance of new export infrastructure is located on the Gulf Coast. Port congestion, notably in Houston, an essential energy port for the world, limits energy-throughput capacity.

Pipelines transport the majority of oil and natural gas across the country. Additional modes of transportation, such as rail, marine, and trucks, play a pivotal role in connecting supply basins to markets. This interdependent system of transportation has enabled the United States to become the world's largest producer of oil and natural gas, connecting major producing fields like the Permian and the Marcellus to domestic refiners and chemical manufacturers, as well as export facilities.

Even in large or rapid fluctuations in supply or demand, the U.S. infrastructure system is extremely resilient, largely due to large, geographically dispersed crude oil, refined products, NGL, and natural gas storage facilities. The highly integrated and interdependent nature of the various modes of transportation can be used to mitigate a disruption. Of course, these interdependencies can also lead to negative scenarios where a disruption to one component can spur a chain reaction to the other components and commodities. Resiliency is enhanced by allowing industry to build infrastructure to adapt and adjust to the ever-changing supply and demand dynamics. In light of the concentration of activity building on the Gulf Coast, the future resiliency of our infrastructure system could be improved with increased geographic diversity. Regulatory or legislative actions that frustrate infrastructure growth negatively impact resiliency.

The nation's energy infrastructure is essential to America's energy supply and use, and is also a critical component of the country's long-term strategic interests, from economic growth to reduced emissions. The nation's oil and natural gas supply abundance has narrowed the U.S. trade deficit and improved the competitiveness of U.S. manufacturing, luring domestic and international investment in the oil and natural gas industry, including petrochemicals, and other energy-intensive industries. The benefits of America's energy abundance touches individual households in the form of job growth, as well as reduced and more stable energy prices.

To continue to harness the abundance of American oil and natural gas supply, further investment in the country's energy transportation infrastructure is needed. This chapter describes the significant investment in this growth that has already been announced, is underway, and will be needed in the future to supply domestic needs and support the projected growth in U.S. exports. All of this work will require the coordination of the oil and natural gas industry and government and nongovernment stakeholders, as well as a transparent and predictable regulatory framework.

II. THE HISTORY, EVOLUTION, AND CURRENT STATE OF THE U.S. OIL AND NATURAL GAS TRANSPORTATION SYSTEMS

Infrastructure is a critical component in the production of crude oil, refined products, natural gas, and NGLs, but the process of infrastructure development is quite different for each of the commodities and varies depending on the producing basin. However, there are four attributes that generally determine what infrastructure is needed, how it gets developed, and the likelihood of its construction.

A. Four Attributes That Determine Infrastructure Needs

1. Commodity—Type and Growth Trajectory

The infrastructure requirements for each energy commodity are determined by the physical characteristics of that commodity, and by the projected growth trajectory for the commodity in specific production areas. A commodity's physical characteristics—which include (1) whether it is transported as a liquid or a gas, (2) what kind of processing is needed prior to transportation to market, (3) the need to keep the product under pressure or cryogenically chilled, and (4) the viscosity of liquid products—determine whether the commodity can be moved by rail and truck, etc. For some commodities, such as natural gas and ethane, pipeline transportation for domestic flows is almost always necessary. For others, such as crude oil and propane, transportation alternatives (truck, rail, barge, ship) are possible. As for the production growth trajectory, if produced volumes are large and growing fast, with the prospect of relatively long-term robust production growth, pipeline transportation will usually be the best, most cost-effective infrastructure alternative. If production growth is slower, or the future pattern is unpredictable, other transportation alternatives may be more suitable.

2. Market — Distance and Characteristics

Infrastructure cost is generally proportional to distance from the production source to the destination market. In other words, the longer the distance an energy commodity must be transported to reach a suitable market, the costlier the infrastructure to support that transportation is likely to be. The nature of the market also has an impact on infrastructure cost. Some markets, such as residential and commercial natural gas demand in the Northeast, are highly weather-sensitive, with large seasonal shifts and daily swings based on temperature variation. Similarly, power generation loads are characterized by large swings as individual generators are dispatched or ramped down, depending on market structure and electric load. The infrastructure required to serve heating and generation markets must accommodate these swings in demand, typically by the use of storage. Other markets, such as ethane feedstocks for petrochemical plants, are usually characterized by a consistent daily demand profile that only varies for plant maintenance and downtime. Infrastructure required to move longer distances and provide greater flexibility will generally be more expensive, and thus more challenging to support from an economic perspective. If the investment required for infrastructure development is not economically viable, it will not be built. This last point is key: market forces drive the development of energy infrastructure. However, the role of federal and state governments is critical in streamlining approvals and reducing barriers to the development of infrastructure projects that make economic sense.

3. Existing/Legacy Infrastructure

The use of legacy infrastructure can provide important advantages in terms of cost savings and impact minimization. For example, where it is possible to repurpose existing pipelines, such as reversing pipes between the Gulf Coast and the Northeast to enable Marcellus/Utica gas to move south, the cost of infrastructure development can be greatly reduced, as can development timelines and environmental impacts. From 2010 through 2018, crude oil transportation infrastructure was grown with expansion, flow reversal, and greenfield projects adding 7,709 thousand barrels per day (MB/D) in capacity. During this same period, gas transportation projects added 23.8 billion cubic feet per day (BCF/D) in transportation capacity. However, most of the existing infrastructure in the major shale basins that could be repurposed already has been, and much of the incremental capacity needed now must come from new, greenfield construction. Nearly 8,000 MB/D in crude oil pipeline capacity is expected to be added over the next 2 to 4 years, while gas pipeline capacity and NGL pipeline capacity is expected to grow by 18 BCF/D and 3,505 MB/D.

4. Infrastructure Development Environment

The necessary economic, regulatory, and policy preconditions must be present to enable infrastructure investment. Where new construction is seriously challenged by regulations or policies, projects may be postponed or even canceled due to the added costs that can accrue while companies seek to demonstrate their projects' compliance with the prevailing regulations. Uncertainty regarding the prospects for necessary approvals has a negative impact on project economics, and can result in the abandonment of infrastructure development, resulting in constraints on production growth.

Each investment in energy infrastructure must meet the needs of the market to facilitate the flow of an energy commodity from the source of production to a viable destination market. Only through continued investment in energy infrastructure can the benefits of the shale abundance be maintained and extended into the decades to come.

> ***Finding:*** While market dynamics drive demand for diverse modes of transportation, the infrastructure system typically relies on pipelines as part of the long-term solution to efficiently and safely move supply to market centers.

B. Crude Oil Infrastructure History and Current State

1. General Overview of Transportation System

The crude oil transportation system serves as the critical link between production areas and demand centers. It has evolved over time to facilitate the flow of crude oil between and across regions, as well as to employ a diverse range of transportation modes. The current crude oil transportation system can be characterized broadly in two primary supply chain flows, which are further described as follows:

- Flows from the wellhead (production source) to market centers, which consist of either a domestic refinery or an export terminal
- Flows from marine import terminals to domestic refining centers.

While pipelines are the largest and most critical mode of transportation employed in the crude oil system, accounting for 91% in 2017, the integration of various modes including rail, trucks, and marine, is a key characteristic that enables the high level of reliability and flexibility of the crude oil transportation system.[1]

1 Bureau of Transportation Statistics, "Crude Oil and Petroleum Products Transported in the United States by Mode," https://www.bts.gov/content/crude-oil-and-petroleum-products-transported-united-states-mode (accessed July 29, 2019).

There are four main modes of transportation for crude oil:

- **Pipelines** are the most commonly used form of oil transportation to move crude oil from the wellhead to an end market and serve as the lowest-cost and most reliable solution for any sizable volume with long-term duration. Gathering pipelines deliver crude oil from the wellhead to the nearest market center or significant storage location. Long-haul pipelines deliver crude oil from significant storage locations to market centers.
- **Rail** is a viable alternative to long-haul pipelines for newly emerging oil reserves and areas with constrained pipeline capacity; and may serve as the marginal mode of transportation in the short- to medium-term as pipelines are developed. Cost for this mode of transportation may be more or less favorable than pipeline transportation, depending on the origin and destinations involved. Rail is extremely important to crude oil resiliency, especially in regions where there is limited pipeline access.
- **Trucks** serve as the most flexible mode of transportation with the least amount of storage capacity. Trucks often serve as a marginal mode of transportation and serve as a short-term solution.
- **Marine vessels** serve as a cost-efficient mode of transportation between facilities located along the coast and the inland waterway system.

Each of these modes of transportation provides a degree of resiliency in the sense that if one mode of transportation is constrained, another mode will be mobilized to fill that void.

a. Resiliency through Infrastructure Interconnectivity

The U.S. crude oil transportation system has developed resiliency not only through different modes of transportation, but also through the sheer number of transportation routes to get a barrel of crude oil to market, also known as infrastructure interconnectedness (Figure 2-1). The crude oil transportation supply chain is primarily made up of five categories:

- Trucking serves as the marginal mode of transportation prior to implementation of **gathering**

pipeline systems, as well as a permanent transportation link in certain situations such as shipping crude oil to nearby refineries.

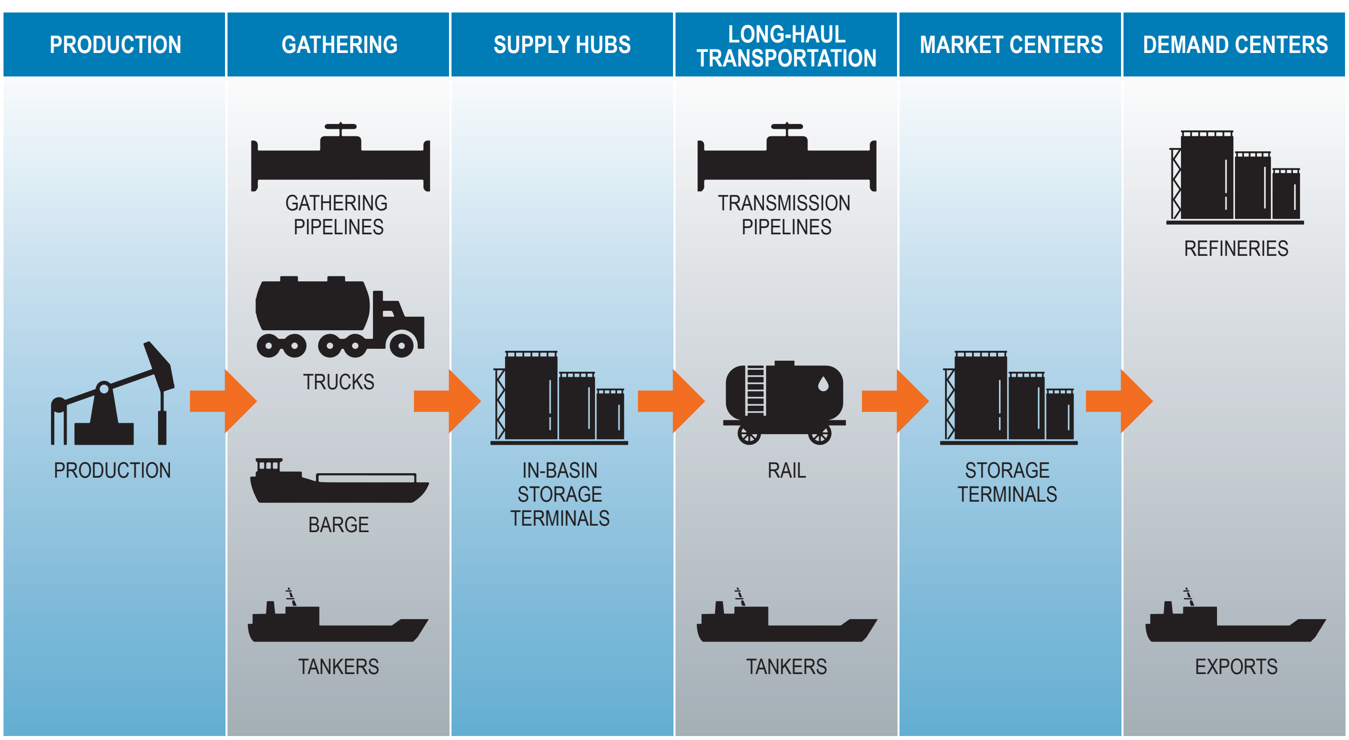
- **Supply hubs** consist of large crude oil storage tanks located within a producing basin that aggregate production into a single location in preparation for long-haul pipeline or rail transportation.
- **Long-haul transportation** (pipeline, rail, and marine transportation) deliver crude oil from supply hubs to market centers located upstream of demand markets.
- **Market centers** consist of storage terminals which are often connected to long-haul transportation systems which ultimately serve as supply sources for refinery and export demand. Market centers typically provide liquidity and price transparency in the marketplace.
- **Demand centers** consist of refineries and export docks which source supply from market centers. Refineries source crude oil from market centers to produce refined products, while crude oil export docks source crude oil from market centers to serve domestic and international waterborne markets.

Specific market considerations inform market participants on the most optimal mode of crude oil transportation. Crude oil producers can leverage a variety of modes of transportation depending on the volume, distance, and speed to market.

Finding: Increases in crude oil supply can get to market quickly because of diverse transportation options.

b. Crude Oil Pipelines

Crude oil pipelines are used throughout the crude oil supply chain and range from small-diameter gathering lines (2" to 10") to larger-diameter transmission lines (12" to 42"). Additionally, pipeline infrastructure is utilized in both



Source: Plains All American, adapted by NPC.

Figure 2-1. *Crude Oil Supply Chain Example* onshore and offshore environments. Gathering pipelines transport crude oil from the wellhead to central facilities or terminals so that oil can enter storage tanks or flow directly into long-haul pipelines. Storage terminals are the primary and most efficient means of aggregating initial production.

Historically, crude oil gathering systems were relatively simple in scope and operations. They were also highly localized within producing basins. The nature of production in shale basins has transformed the modern gathering system into highly complex systems that often span hundreds of miles.

Large-diameter transmission lines transport crude oil from supply areas—either producing regions or import facilities—to market centers. Recent large-diameter pipelines typically range from 20" to 36" in diameter. There are historical exceptions to this size, including the Trans-Alaska Pipeline (48" diameter) and Capline (42" diameter). Offshore pipelines follow the same general supply chain patterns as onshore pipelines but require specialized equipment for subsea and marine conditions.

c. Crude Oil Storage

Critical and complementary components of crude oil pipelines are inland and marine storage. Inland long-haul pipelines typically converge at hub locations where storage acts as a balancing mechanism for pipelines and demand centers. Large hubs are also necessary at origination locations of transmission hubs. Key inland hub locations are found in Oklahoma, Texas, Illinois, and Wyoming.

Marine terminals serve as staging locations for flows to domestic demand centers and as staging areas for both the import and export of crude oil. They have similar characteristics to inland storage hubs but have the additional complexity of receiving and delivering crude oil to and from marine vessels. Key marine storage hubs are found primarily along the U.S. Gulf Coast. Dock infrastructure requires pipeline connectivity, ample storage capacity to act as a staging point for transfer, significant acreage footprint, and, of course, access to water.

The Strategic Petroleum Reserve (SPR) is a testament to how critical the nation has historically viewed crude oil storage. With an authorized storage capacity of 713.5 million barrels, the SPR is the world's largest emergency supply of crude oil in the world.[2] Its origins can be traced back to the early years of the 20th century, when the U.S. Navy completed the conversion of its warships from coal to oil-fired propulsion. The onset of World War I raised concerns about the ready availability of oil for the military, so the government enacted a series of laws between 1912 and 1923 to set aside four areas of land that had major oil reserves strictly for naval use, designated as the Naval Petroleum Reserves (or NPRs). NPR Number 4 was the Alaska NPR, established by President Warren G. Harding in 1923. It set aside 23,599,999 acres of land with an estimated reserve of 896 million barrels of crude oil and 53 trillion cubic feet of natural gas.

Due to the discovery and development of major oil fields in Texas and Oklahoma, supply concerns were alleviated, and no further areas were reserved for the Navy. In mid-century, major developments of low-cost oil were made in the Middle East, and oil began flowing to U.S. refineries. The United States found itself dependent on this flow of foreign oil at a time when the U.S. and European oil companies' control of the Middle East oil fields was being challenged by these Middle East nations.

In the early 1970s, the U.S. government grew increasingly concerned about the security of supply from the Middle East and initiated discussions on creating a federal oil reserve to provide a buffer that could be drawn upon quickly should there be any supply disruption of foreign oil. These concerns were validated by the Arab Oil Embargo of 1973 and resulted in the passing of the Energy Policy and Conservation Act, signed by President Ford on December 22, 1975. The Act called for the establishment of a "Strategic Petroleum Reserve Office," with a mandate to establish

2 U.S. Energy Information Administration, "Working and Net Available Shell Storage Capacity," May 2019, https://www.eia.gov/petroleum/storagecapacity/storagecapacity.pdf; and U.S. Department of Energy, Office of Fossil Energy, "SPR Quick Facts and FAQs," https://www.energy.gov/fe/services/petroleum-reserves/strategic-petroleum-reserve/spr-quick-facts-and-faqs (accessed October 1, 2019).

a Strategic Petroleum Reserve by December 15, 1976. The ultimate goal was to stockpile one billion barrels of crude oil. On April 18, 1977, the SPR plan was put into effect following Congressional approval.

The U.S. Gulf Coast region was the logical place to locate this petroleum reserve; not only did it have a multitude of salt caverns that could be used for storage, it was also the main location for the refineries that needed the crude oil. On July 21, 1977, the first oil, 420,000 barrels of Saudi Arabian light crude oil, was delivered to the SPR, marking the beginning of the inventory build. The SPR was filled to its 727 million barrels capacity on December 27, 2009, which was also the highest volume ever stored.

Crude oil has been released from the SPR several times in its history, under four main categories:

- Emergency Drawdowns: The President is allowed to draw down the reserve as an emergency response measure should the United States be faced with a disruption in oil supply that would cause economic harm to the country. This has happened three times:
  - 1990-1991: 17.3 million barrels were withdrawn during the Desert Shield/Storm conflict
  - 2005: 11.0 million barrels were withdrawn as a result of Hurricane Katrina
  - 2011: 30.6 million barrels were withdrawn as part of an International Energy Agency (IEA) coordinated response to supply disruptions in Libya and elsewhere.
- Crude Oil Test Sales: These are conducted to ensure the readiness and operability of the Reserve and its personnel to carry out a Presidential order to draw down and sell inventory. Examples include:
  - 1985: A test sale of 1.0 million barrels
  - 1990: 3.9 million barrels sold to test readiness for Desert Shield
  - 2014: A test sale of 5.0 million barrels.
- Exchanges: The SPR can provide barrels to private companies that are having severe supply issues in exchange for an equivalent amount plus an additional "premium" volume of crude oil in the future. The best examples are just after hurricane events, where the refineries are having short-term supply issues, or when there have been constraints on the Houston Ship Channel, to name but a few. The SPR has provided crude oil under this authority on 12 separate occasions.
- Nonemergency Sales: These typically occur when the market price is elevated, and either the administration or Congress wants to raise additional revenue to reinvest in the SPR infrastructure or reduce the federal deficit. These typically require separate Congressional action to initiate.

Fast forward to today. In 2016, the U.S. SPR contained an estimated 695 million barrels of crude oil, stored in salt domes along the U.S. Gulf Coast. At the time, this was equivalent to 143 days of net import protection. Planned sales from the SPR over the next 10 years will bring the reserve down to approximately 400 million barrels by the beginning of 2029.[3]

As domestic production continues to increase and imports decline, the equivalent days of net import protection has increased, raising the question about what should be the targeted buffer storage volume today. However, with the ban on U.S. crude oil exports lifted, SPR crude oil can be exported into the global market, thus reducing crude oil prices following a severe supply disruption.

The SPR also plays an important deterrent role in preventing possible supply disruptions. Since major producers know that the SPR will be called upon should there be a large crude oil supply disruption, they know that they might not gain much from disrupting supply as the supply shortage and price jump will be short-lived. By having a large stockpile of emergency reserves of crude oil, the

3 U.S. Department of Energy, Strategic Petroleum Reserve Inventory, September 2019, https://www.spr.doe.gov/dir/dir.html (accessed October 1, 2019).

SPR helps deter large supply disruptions, thus keeping prices such as gasoline, diesel fuel, and jet fuel from rising higher than they otherwise would.

2. History and Current State of the Crude Oil Transportation System

a. Major Flow Patterns

Since the early emergence of a modern crude oil market, the U.S. crude oil transportation system has consistently responded to changing supply and demand dynamics. The system originated with relatively simple regional movements between supply sources and demand centers. However, even in the earliest developments in Pennsylvania, various transportation modes were employed to support the value chain. Pipelines were introduced soon after the first crude oil discoveries, see text box "The First Pipeline," and have remained the dominant mode employed in the modern transportation system, as illustrtaed by the "Alaska TAPS" text box. Today, the system consists of the vast array of transportation modes; however, the broader system continues to evolve in response to market dynamics. Identifying the broad market dynamics, the resulting crude oil flow patterns and the development of related infrastructure help set the backdrop for understanding the current infrastructure system.

b. Impact of Canadian Imports

Initially, the crude oil transportation system connected domestic supply with domestic demand centers exclusively. However, between 1954 and 1970, U.S. crude oil refining capacity and product demand expanded beyond the limits of domestic supply sources, as depicted in Figure 2-2. As a result, the system evolved to accommodate flows of imported crude oil into coastal terminals and then out to refining centers. Significant dock and marine storage infrastructure was developed to import foreign crude oil into refining centers. The Gulf Coast emerged as the largest refining center in the United States and therefore became a key destination for both pipeline and import terminal infrastructure. From 1970 to 2010, steadily declining domestic supply was replaced by further increases in foreign waterborne imports and Canadian imports, depicted in Figure 2-2. Growth in Canadian production altered historical flow patterns and resulted in the development of large crude oil transportation infrastructure. In many cases large pipeline infrastructure originating in Canada was built into the United States.

THE FIRST PIPELINE

In the early 1860s, as the demand for kerosene to replace whale oil used in lamps continued to grow, oil wells were multiplying rapidly in the Northeast United States. At that time, most crude oil was transported by wagons on rough roads, by the Teamsters, at high costs. In response to these high costs, the oil producers began building short pipelines between the oil wells and shipping depots or refineries. An oil worker from New Jersey is credited with building the first successful pipeline in 1865 that extended 5 miles and connected the Pithole discovery to the Oil Creek railroad. The pipeline was of a welded iron construction, and was buried two feet underground to protect it from sabotage.

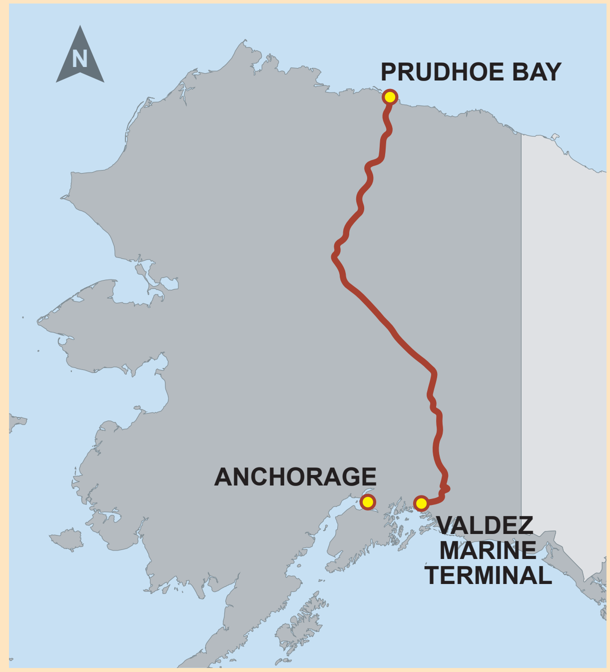
c. Crude Oil Transportation Infrastructure in the Shale Era

Since 2008, increasing shale production and the lifting of the crude oil export ban has again changed historical flow patterns in the crude oil transportation system. In the shale era, major infrastructure has been developed across all modes in response to expected growth from new supply sources. Each of the major onshore shale basins has required unique transportation systems, including large-scale gathering and intrabasin systems, to move oil away from the relevant supply area to the key market hubs. Currently, the primary infrastructure push across all shale basins and key hubs is to facilitate movements to export facilities on the Gulf Coast. The associated export infrastructure on the Gulf Coast is also a major focus area for the next wave of development.

As of 2018, there were 80,580 miles of crude oil transmission pipelines in service stretched across the United States. The U.S. pipeline system is

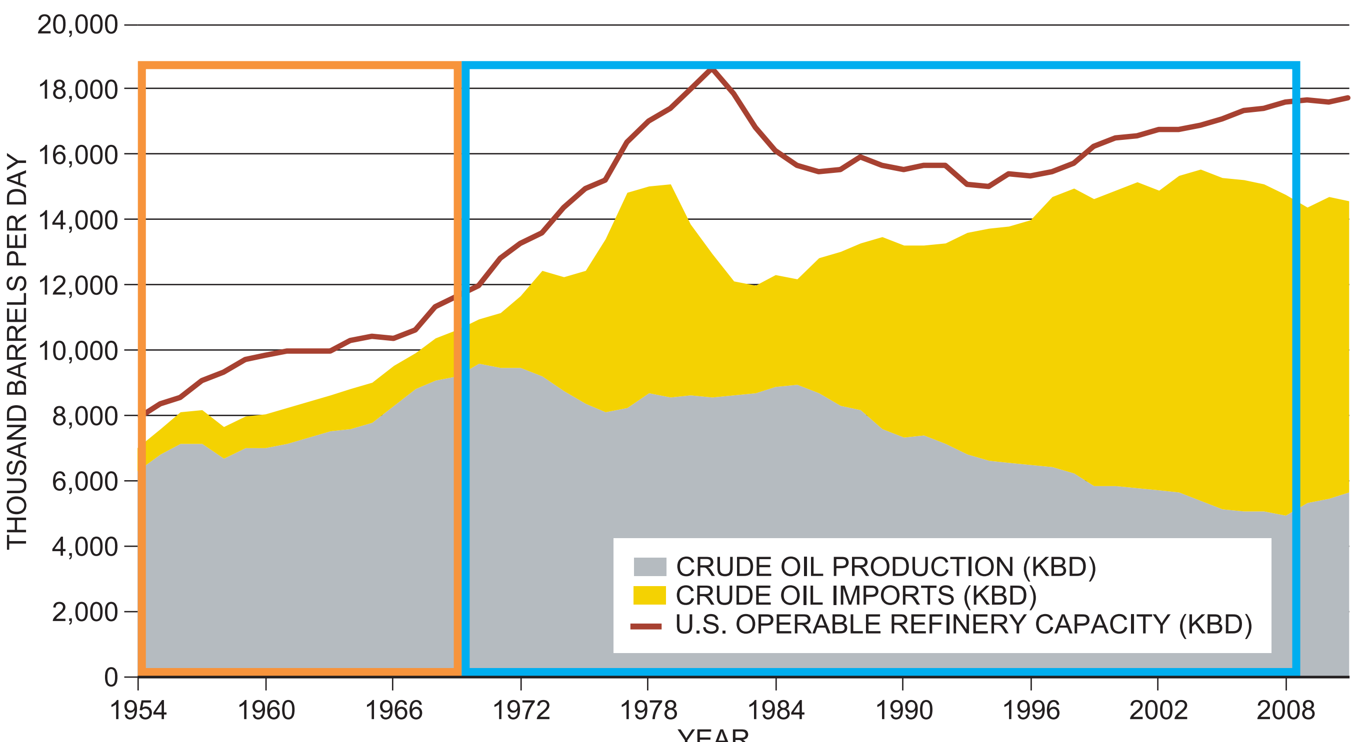
ALASKA TAPS

With the discovery of crude oil reserves on the North Slope in 1968, and subsequent construction of the Trans-Alaska Pipeline System (TAPS) pipeline for movements of Alaska North Slope (ANS) crude to Southcentral Alaska, a new economy was built for the state of Alaska. Since TAPS became operational in 1977, it has been the backbone of Alaska's economy. Pictured in the map below, the 800-mile, the 48-inch TAPS pipeline is one of the largest pipeline systems in the world. Privately constructed, TAPS is an engineering marvel, with more than half the pipeline constructed above ground due to the permafrost across most of the state. Since its 1977 start-up, ANS production peaked in 1988 at just over 2 million barrels per day. ANS production has steadily declined since the 1988 peak, leveling off in the 505 to 535 kbd range during the 2013 to 2108 timeframe.



Source: PennWell - MAPSearch.

Map of Trans-Alaska Pipeline System



Source: EIA, 2011 Annual Energy Review.

Figure 2-2. *U.S. Crude Oil Flows 1954-2010* shown in Figure 2-3. As depicted in Figure 2-4, 35% of that mileage was placed into service between 2010 and 2018.[4]

d. Impact of Shale on Domestic Crude Oil Transportation — Changing Regional Relationships

Shale oil development has resulted in the highest U.S. oil production in history, radically changing regional relationships and shifting the nation toward becoming a net energy exporter after decades of being a major net importer of crude oil. The geography of oil production has changed with rising output. Oil production growth is concentrated in a few major basins, with most of the increase coming from the Permian Basin in western Texas and southeast New Mexico, and two new areas of major shale oil production—the Eagle Ford formation in South Texas and the Bakken formation in North Dakota. To accommodate these changes, existing infrastructure was repurposed as much as possible. Existing pipelines were expanded, and the flow direction of other pipelines was reversed. The sheer volume of crude oil moving intra- and inter-regionally also required a significant buildout of new pipeline capacity and the use of alternative crude-by-rail capacity where possible. Further investment in new pipelines is required to support ongoing growth in domestic oil production.

4 Pipeline and Hazardous Materials Safety Administration, *Annual Report for Hazardous Liquid or Carbon Dioxide Systems,* September 3, 2019, https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-hazardous-liquid-or-carbon-dioxide-systems (accessed September 3, 2019).

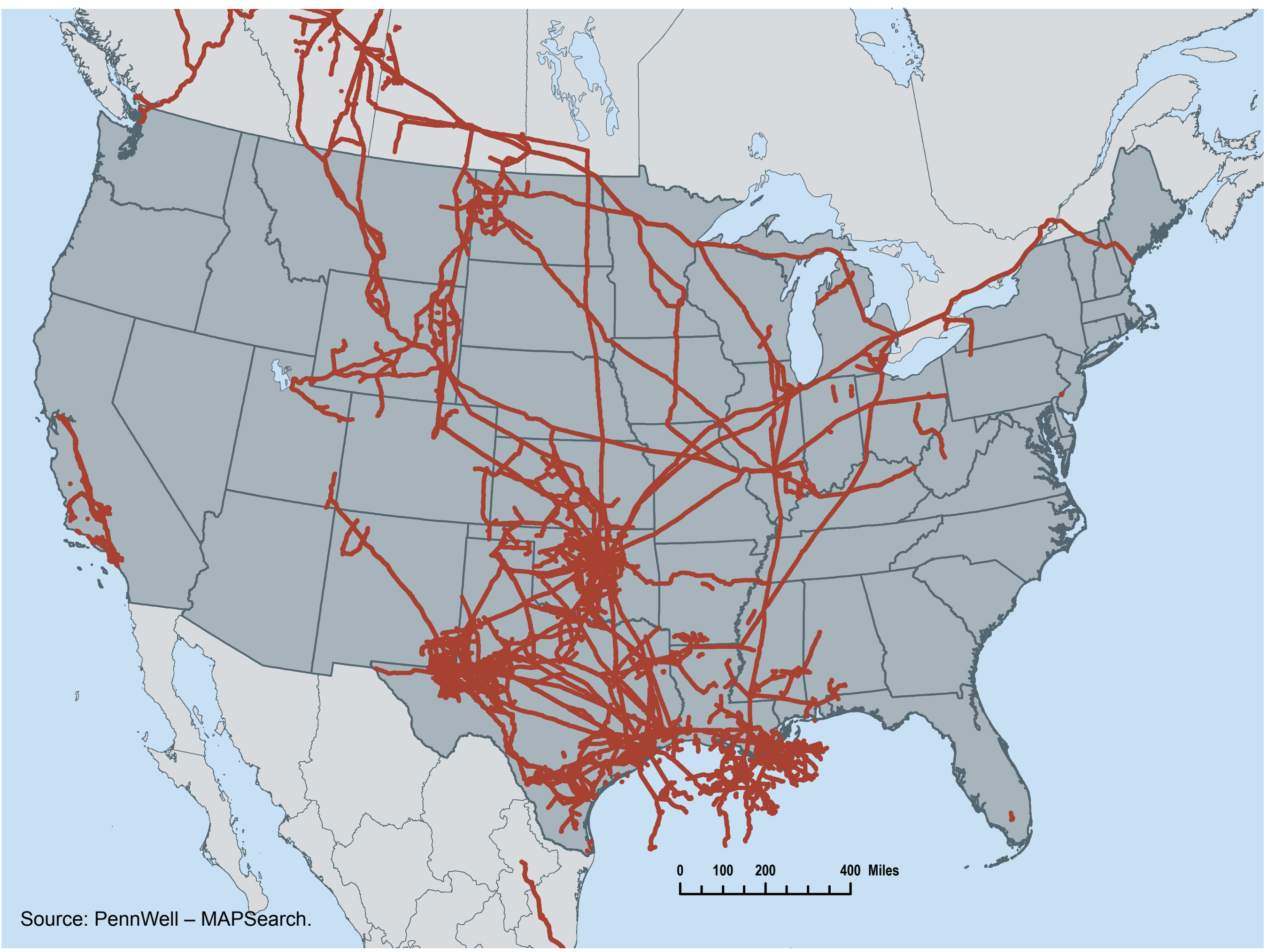
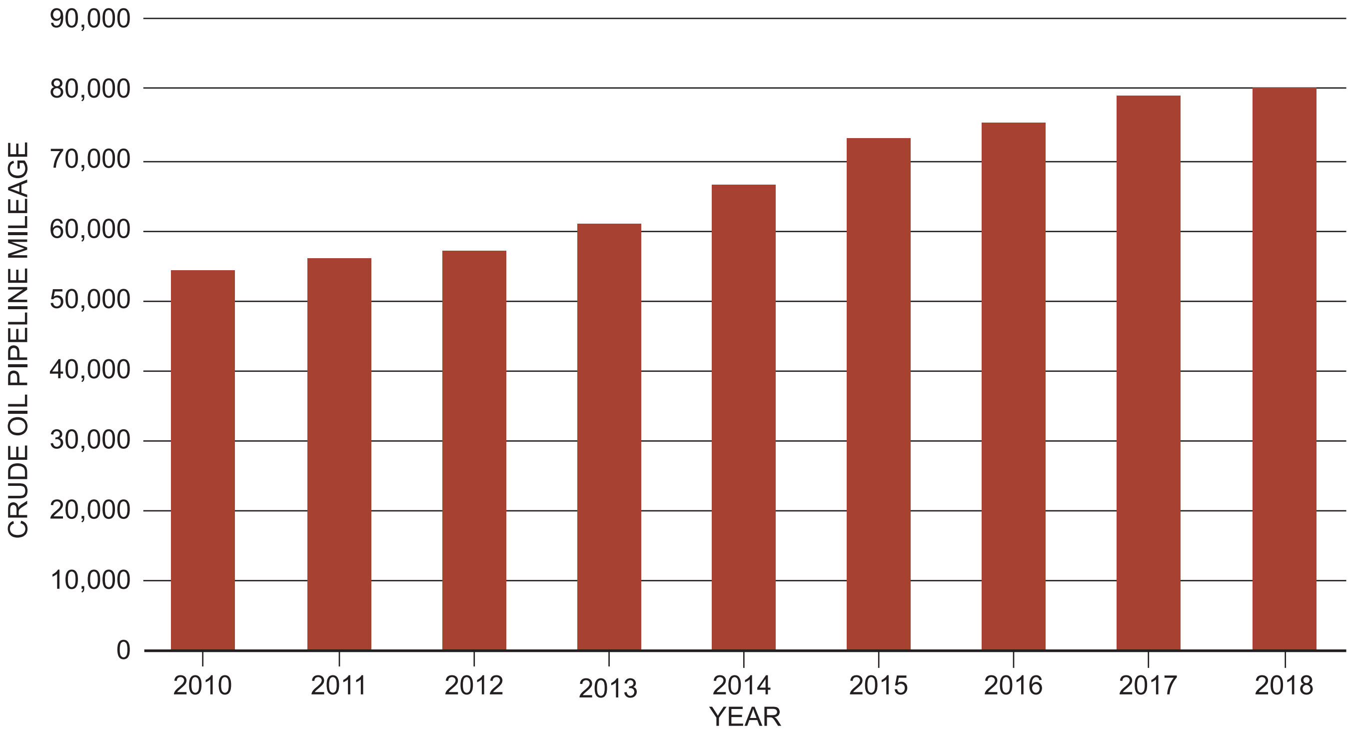


Figure 2-3. *North America Crude Oil Pipelines, June 2019*



Source: Pipeline and Hazardous Materials Safety Administration, Pipeline Data and Statistics.

Figure 2-4. *Crude Oil Products Miles, 2010-2018*

e. Oil Flows Pre- and Post-Shale

In the years immediately prior to shale development, crude oil flowed from the Gulf Coast (onshore and offshore) to feed refineries in the same region, with some flows moving through the Cushing, Oklahoma hub into Midwest markets. Crude oil imports from Canada supplemented Midwest refinery feedstocks. Substantial waterborne crude oil imports arrived on the East Coast while West Coast refinery demand was met primarily with local supplies and inflows from Alaska. These trends are illustrated with the green arrows in Figure 2-5.

As shale production grew, incremental crude oil supplies began flowing south to the Gulf Coast from the Bakken, Oklahoma, and the Rockies, east from the Eagle Ford, and, most important, east from the Permian Basin. Canadian crude oil supplies flowed to the Midwest and also pushed farther south by pipeline and rail to supply refineries along the Gulf Coast and for possible export. These new flow patterns created the need for substantial growth in infrastructure, often from nontraditional supply areas. Bakken crude oil also moved by rail to the West Coast, filling in partially for declining Alaskan supplies and backing out some overseas imports on the West Coast. These trends are illustrated with the red arrows in Figure 2-5.

f. Bakken Development (2017 to 2018)

Shale production techniques were first applied successfully to crude oil on a large scale in North Dakota's Williston Basin–the Bakken. As crude oil production increased, along with associated gas, volumes soon exceeded available pipeline takeaway capacity. Most Bakken crude oil moved by pipeline transits through the hubs at Guernsey, Wyoming, or Clearbrook, Minnesota (Figure 2-6).

Bakken crude oil production increased more than six-fold in 6 years, rising from 0.2 million barrels per day (MMB/D) in 2008 to producing almost 1.3 MMB/D by the end of 2014, accounting for more than 14% of U.S. crude oil production. This magnitude of production was unprecedented

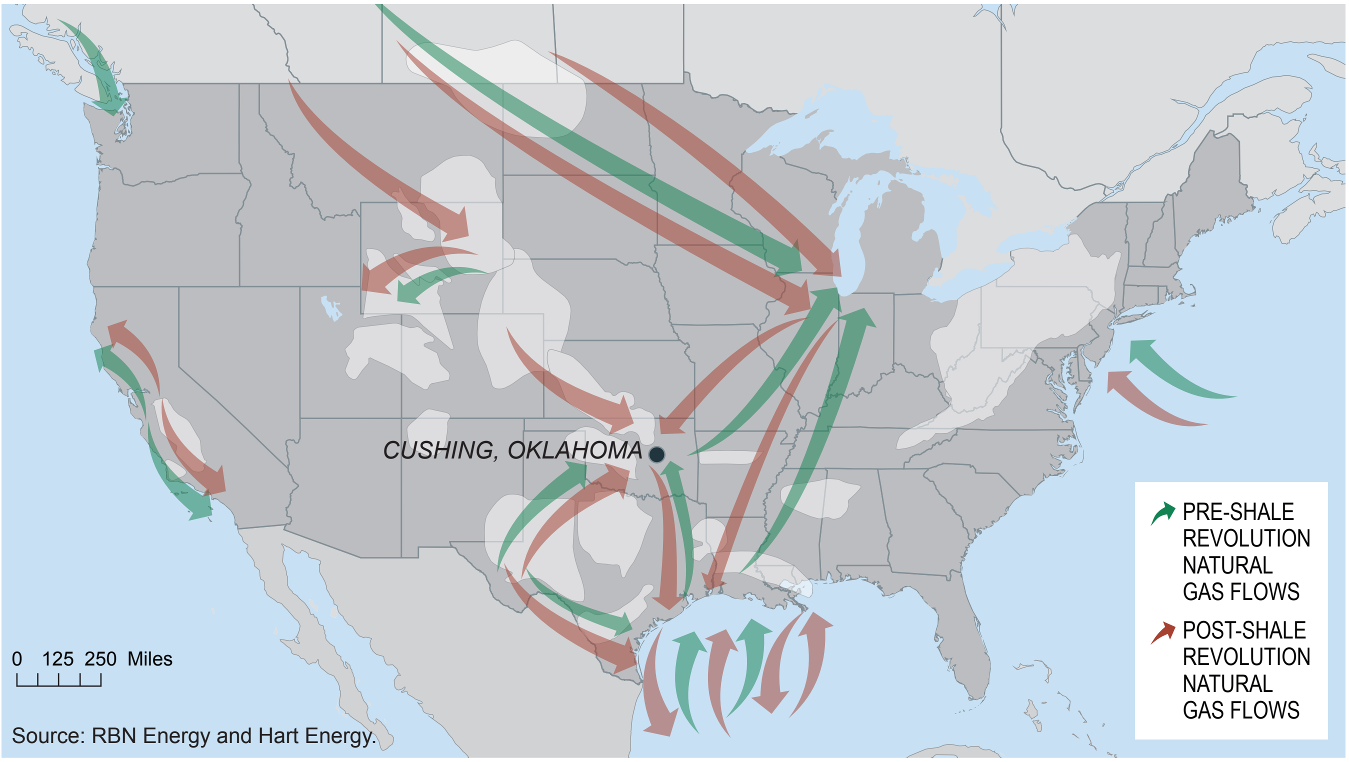
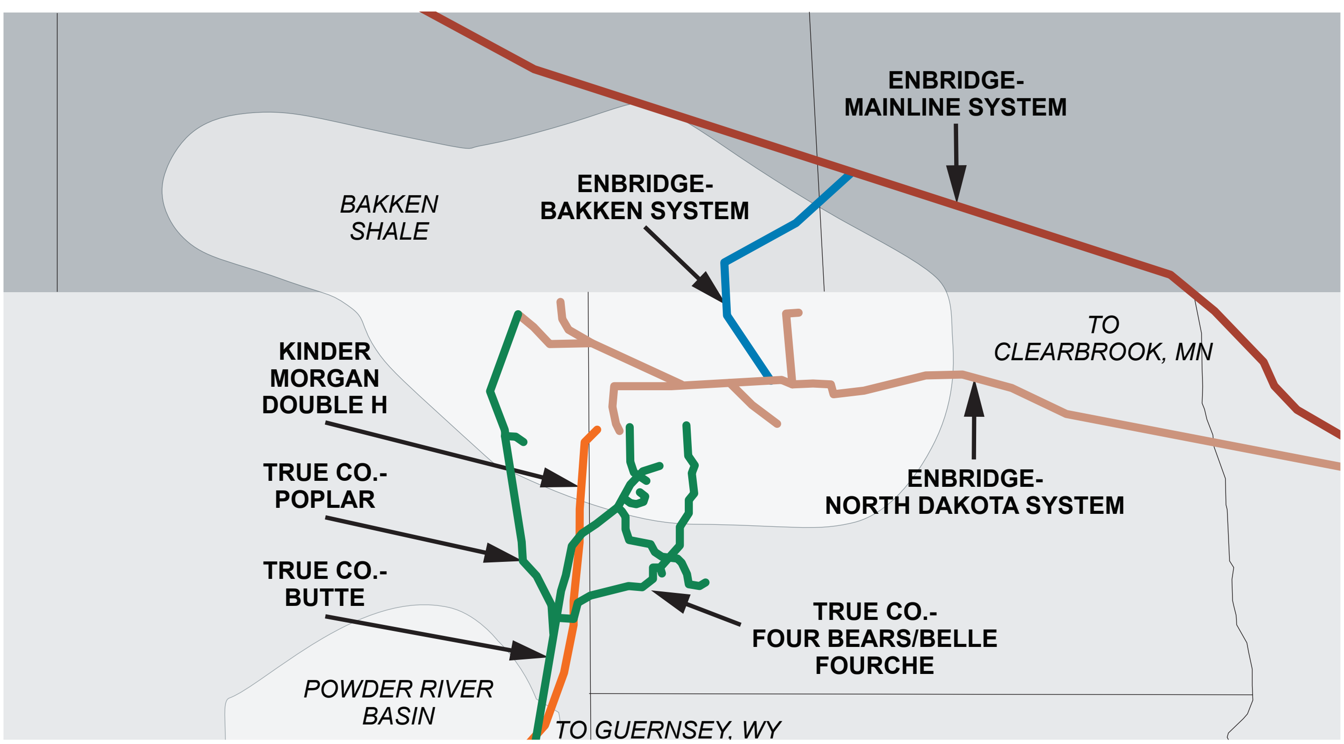


Figure 2-5. *Crude Oil Flows Pre- and Post-Shale*



Source: RBN Energy.

Figure 2-6. *Bakken Crude Oil Pipeline Development* for the Bakken. As crude oil production ramped up, there was not enough local refinery demand or pipeline capacity to move crude oil out of the region. The result was severely constrained take-away capacity, preventing this new supply from getting to market. With long-line pipeline projects out of the Bakken years away from completion, the industry turned to crude-by-rail to move the rising supplies to market.

By early 2012, the price differential between the Bakken and Cushing, Oklahoma, increased substantially, creating deep price discounts for Bakken crude oil—as deep as $28/barrel below Cushing. Prior to the ramp up in production, the Bakken traded at only a few dollars under the Cushing price. The deficiency of takeaway capacity was clear, but it takes years to build a long-haul crude oil pipeline.

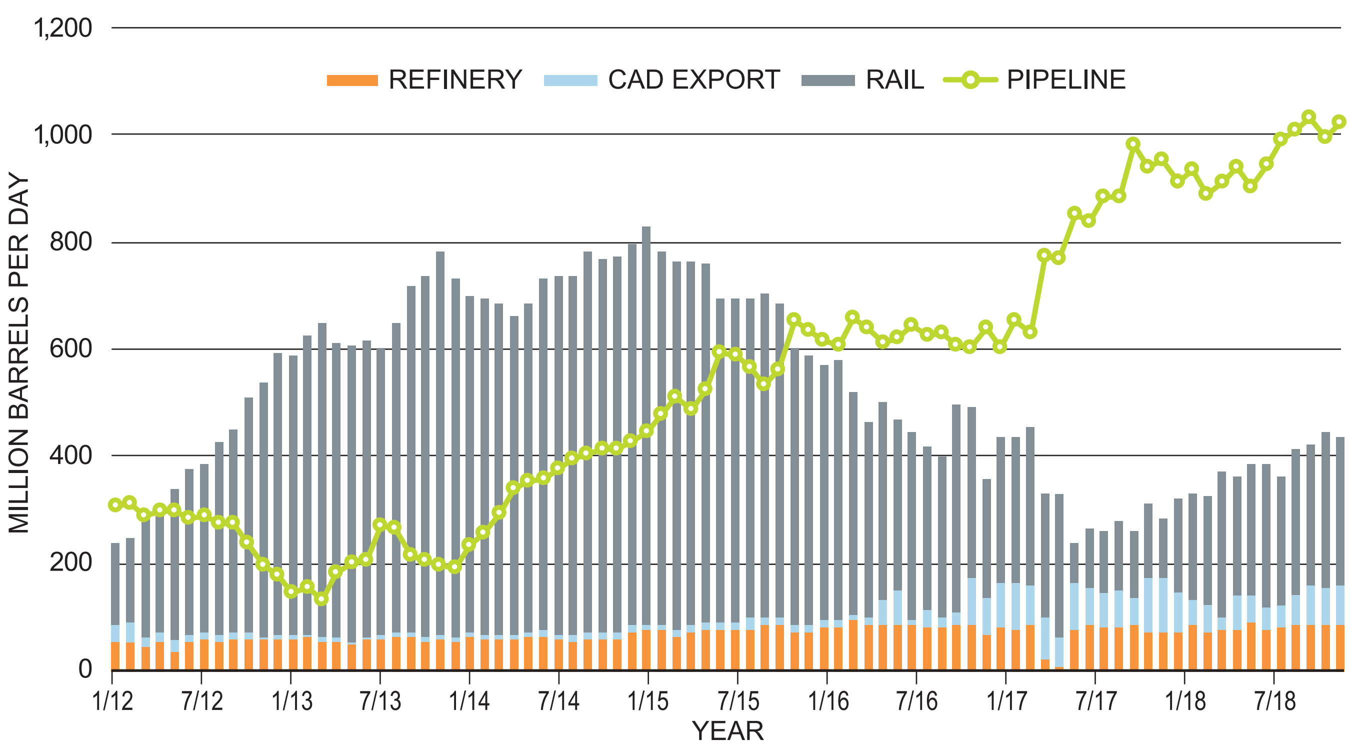
The medium-term solution to takeaway constraints was provided by rail transportation. Not only could rail facilities be built much faster, the up-front capital investment was also lower. As recently as 2011, rail was a very small part of the crude oil transportation network, averaging just over 5,000 railcar deliveries per month in the United States. By early 2013, that number was up to more than 30,000. In 2014, more than half the Bakken crude oil moved out of the region by rail.

From 2012 until 2016, more than 90 rail-loading terminals for crude oil were built or significantly expanded in North America, not only in the Bakken, but in all the major shale oil basins. Another 70 destination terminals were built or expanded elsewhere, mostly on the Gulf Coast, East Coast, and the West Coast.

The Bakken crude-by-rail story illustrates the resiliency of the transportation system. At the end of 2018, the Bakken Shale produced 1.35 MMB/D of crude oil,[5] which is transported via pipeline and railroad (Figure 2-7).[6] During the delayed pipeline

5 North Dakota Department of Mineral Resources, Bakken Oil Production Statistics, February 2019, https://www.dmr.nd.gov/oilgas/stats/historicalbakkenoilstats.pdf (accessed October 5, 2019).

6 North Dakota Pipeline Authority, https://northdakotapipelines.com/.



Source: North Dakota Pipeline Authority, presentation, February 12, 2019, "Industrial Commission Update."

Figure 2-7. *Movement of Crude Oil in the Bakken by Mode* construction, production was able to reach markets via rail, which demonstrates the resiliency of different transportation modes. Once online, the Dakota Access Pipeline was able to transport crude oil to key destinations of Patoka, Illinois, and Nederland, Texas.

In the following years, as new pipeline projects were completed, some facilities were repurposed to unloading inbound sand or handling NGLs, while many remained open as crude oil loaders. Figure 2-8 demonstrates the build of crude oil loading terminals along railroads in the Bakken.

The slowing of Bakken production in 2015 and 2016 in response to lower crude oil prices eased the volume of crude oil shipped by rail, but still did not eliminate the need for new pipeline capacity. Enbridge's pipeline through the region from Canada was still at capacity. The Dakota Access Pipeline (DAPL) entered into service in June 2017, filled to capacity almost immediately, and later expanded to its current capacity. DAPL connects to the Energy Transfer Crude Oil Pipeline from Patoka, Illinois, to Nederland, Texas, which was a repurposed and reversed natural gas pipeline built to help move Bakken barrels to the Gulf Coast. These projects are depicted in Figure 2-9.

g. Rockies Development (2014 to 2018)

The development of shale and tight oil in the Niobrara and other basins in the Rockies also resulted in production growth that quickly filled

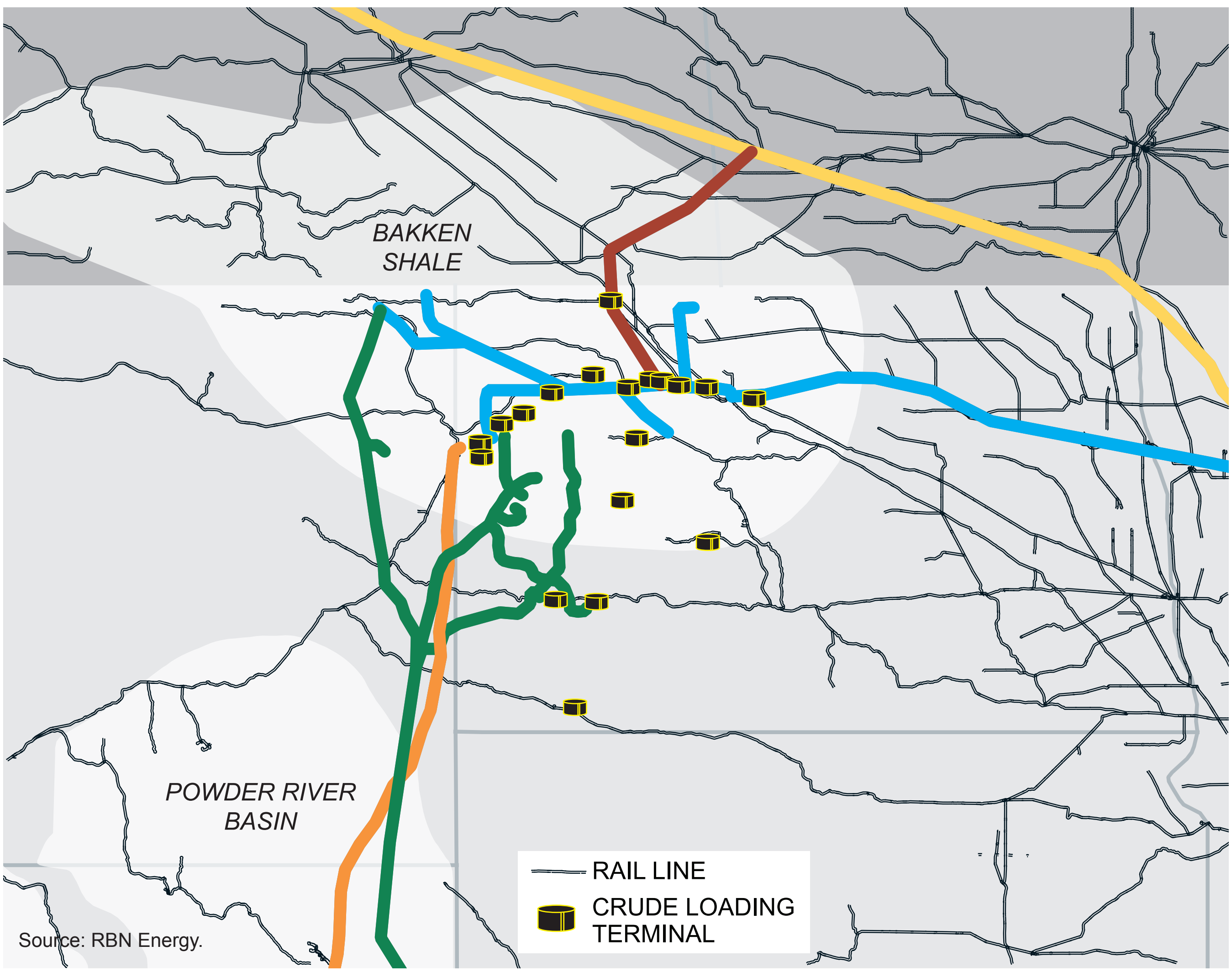


Figure 2-8. *Rail Lines and Crude Oil Loading Terminals in the Bakken*

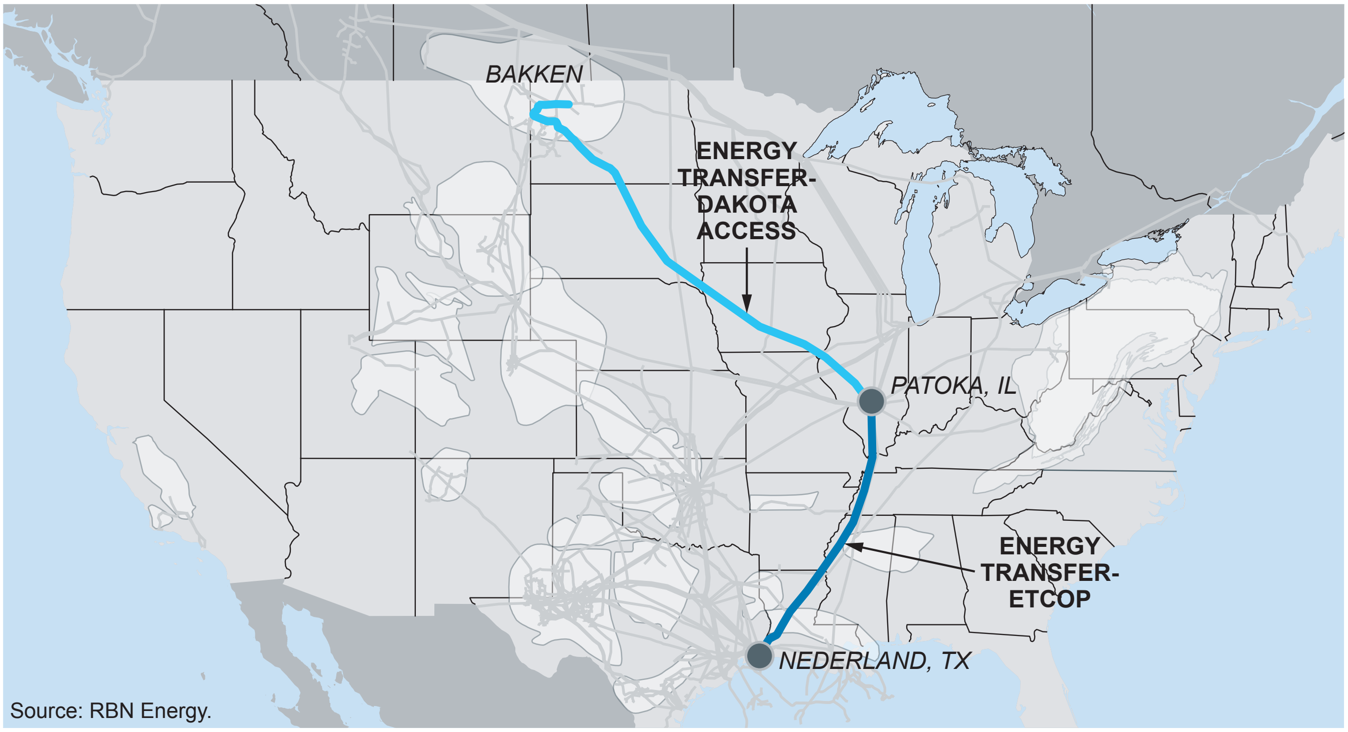


Figure 2-9. *Infrastructure Buildout in the Bakken, 2017-2018*

regional pipelines. Other existing pipelines from the Bakken also began to flood the region. As a result, additional expansions were undertaken to transport crude oil to Patoka, Illinois, and Cushing, Oklahoma. These projects are depicted in Figure 2-10.

h. Midcontinent Inbound/Outbound Pipelines (2010 to 2018)

The growth in Rockies and Bakken production created the need for more takeaway capacity from these regions to the midcontinent. Approximately 1,947 MB/D was added from 2010 to 2018, as depicted in Figure 2-11. Crude oil supply from Canada grew during this period as well, competing for market share and pipeline capacity in the Cushing and Patoka markets.

With so much crude oil flowing into the midcontinent from the Rockies, Patoka, Illinois, and Canada, the Cushing area became so oversupplied by 2011 that Cushing prices fell to discounts as large as $25 below Gulf Coast prices. Between 2011 and 2013, pipeline capacity was reversed to flow south instead of north (the Enterprise/Enbridge Seaway Reversal) and new pipeline capacity was built, including Enterprise/Enbridge Seaway Twin, TC Energy Marketlink, and Plains/Valero Diamond. The Plains/Valero pipeline displaced Gulf Coast supplies to a Memphis refinery with supplies from Cushing. These projects resulted in a net gain of 1,350 MB/D capacity out of Cushing, as depicted in Figure 2-12.

i. Midcontinent Crude Oil Pipeline Projects (2019 to 2024)

In anticipation of further production growth and increasing imports from Canada, another eight major midcontinent pipeline projects totaling 3.8 MMB/D of additional capacity are planned in the 2019 to 2024 period. These projects are depicted in Figure 2-13.

j. Eagle Ford Development (2010 to 2016)

By 2011, the Eagle Ford in South Texas experienced rapid growth in crude oil production, with production growing from 85 MB/D in 2010, to 265 MB/D in 2011, and 630 MB/D in 2012. Various

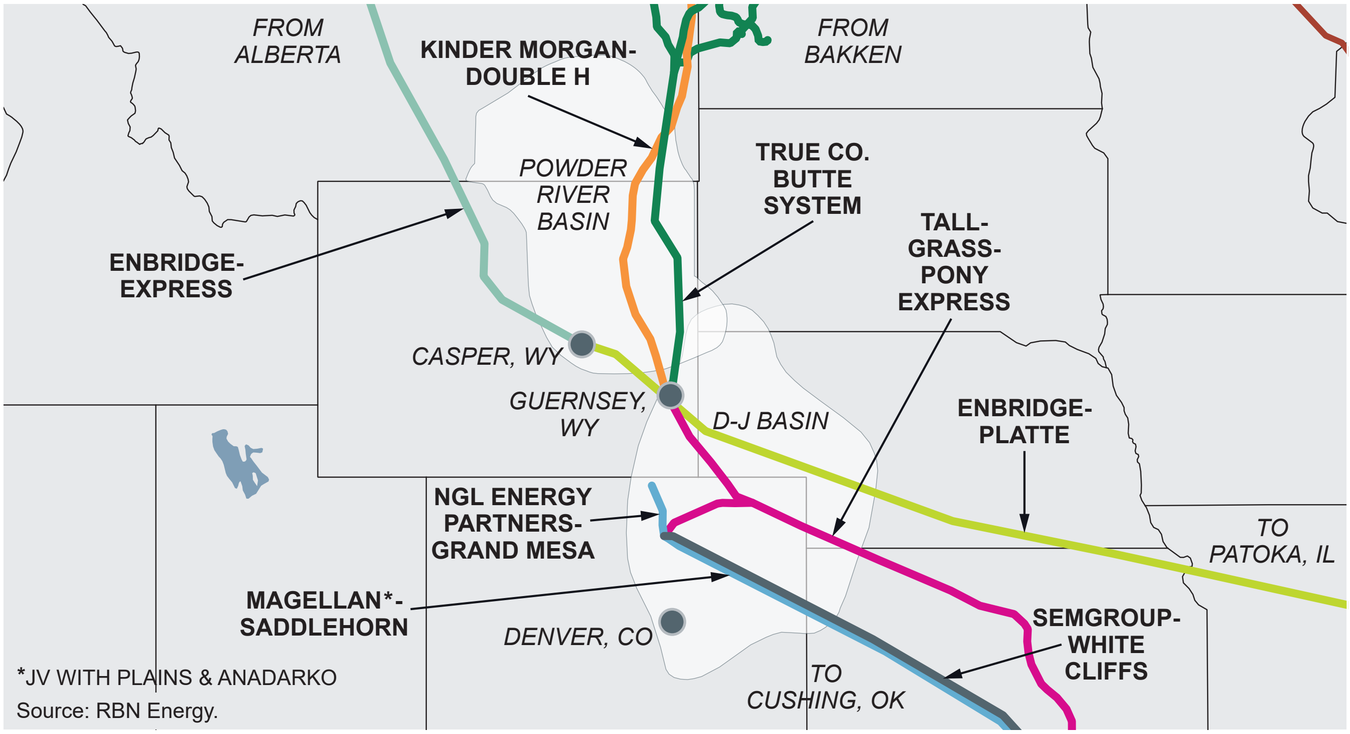


Figure 2-10. *Infrastructure Buildout in the Rockies, 2014-2018*

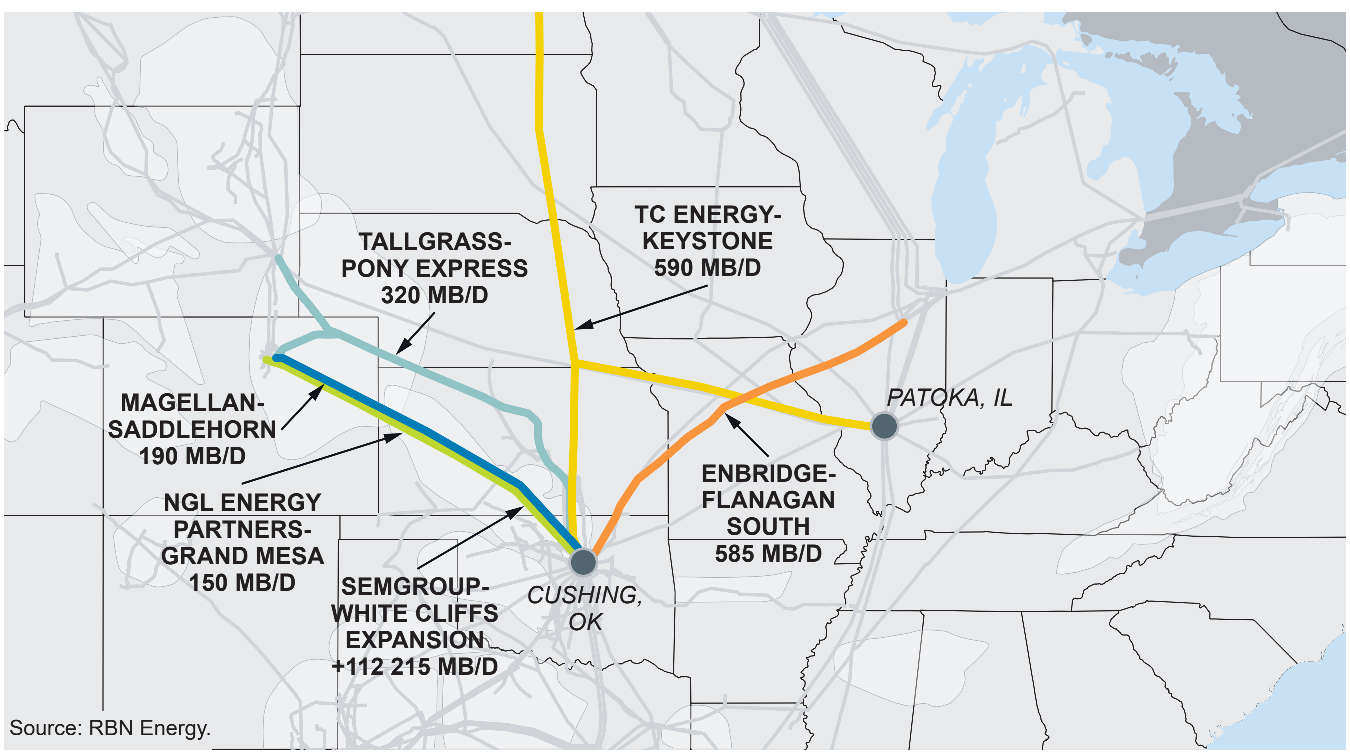


Figure 2-11. *Infrastructure Buildout in the Midcontinent, Inbound Pipelines, 2010-2018*

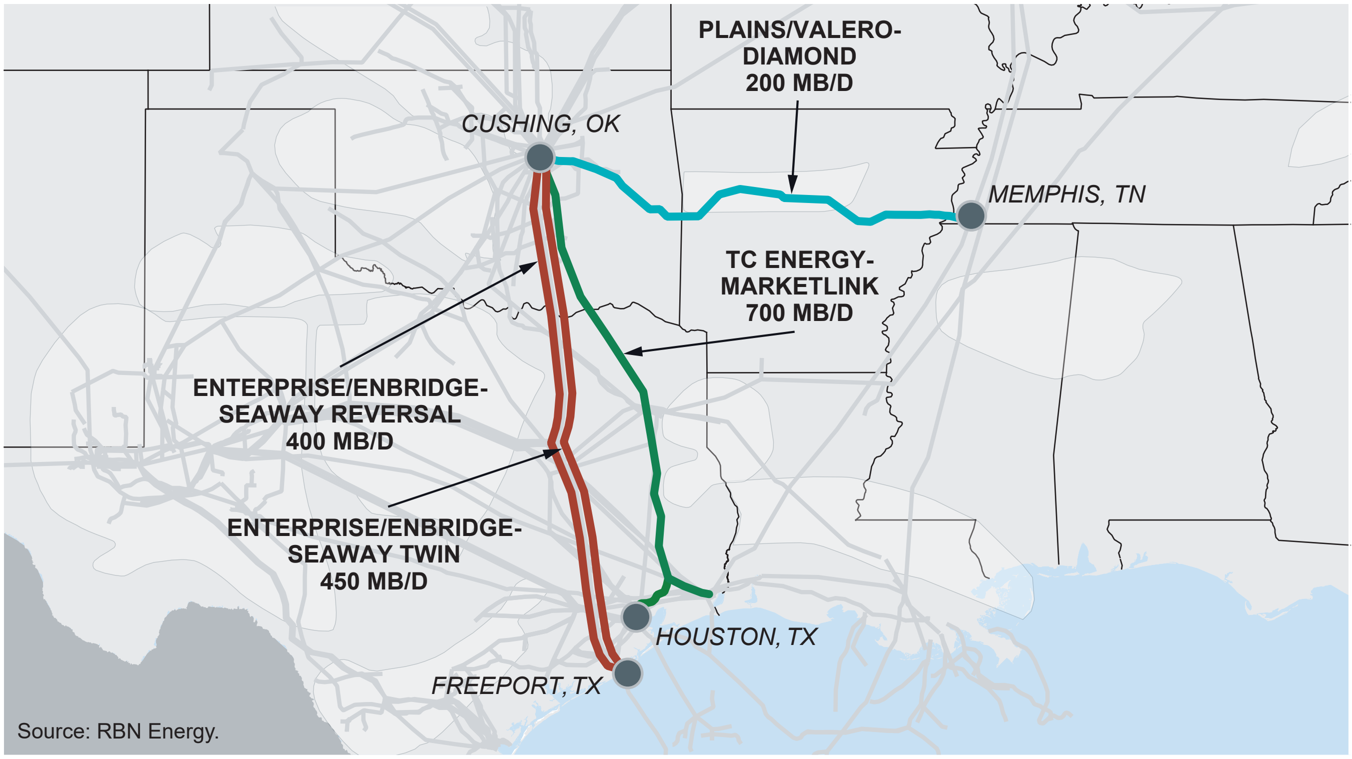


Figure 2-12. *Infrastructure Buildout in the Midcontinent, Outbound Pipelines, 2010-2018*

pipelines were built or expanded, including two routes to Houston—Enterprise Eagle Ford Crude and Kinder Crude and Condensate—and several pipes to nearby Corpus Christi. These projects resulted in an addition of 1,220 MB/D in crude oil takeaway capacity from the Eagle Ford, as depicted in Figure 2-14.

k. Permian Basin Development (2010 to 2016)

During 2010 and 2011, producers started to apply shale production technologies to the Permian Basin. It took some time to achieve success, but production started to increase—from 1 MMB/D in 2011 to 1.2 MMB/D in 2012, 1.4 MMB/D in 2013, and 1.6 MMB/D in 2014. As production increased, Permian Basin prices declined significantly due to transportation capacity constraints.

This domestic supply abundance reached the national/global market that was, in late 2014, already in a state of supply surplus. At the end of 2014, crude oil prices had crashed from the $100/barrel level, ultimately reaching a low of $26.55 in January 2016. The initial drop in oil prices from mid-2014 to early 2015 was primarily driven by supply factors, including booming U.S. oil production, receding geopolitical concerns, and shifting OPEC (Organization of Petroleum Exporting Countries) policies. However, deteriorating demand prospects played a role as well, particularly from mid-2015 to early 2016. This partly explains why the oil price plunge failed to provide a subsequent boost to global activity.[7] Nationally, the number of oil-directed drilling rigs dropped from about 1,600 in 2014 to less than 450 in 2016.[8] Crude oil production declined in all basins except

7 Stocker, M., Baffes, J., and Vorisek, D., "What Triggered the Oil Price Plunge of 2014-2016," World Bank Blogs, January 18, 2018, https://blogs.worldbank.org/developmenttalk/what-triggered-oil-price-plunge-2014-2016-and-why-it-failed-deliver-economic-impetus-eight-charts.

8 U.S. Energy Information Administration, "U.S. oil rig count, based on Baker Hughes," March 22, 2016, *Today in Energy*.

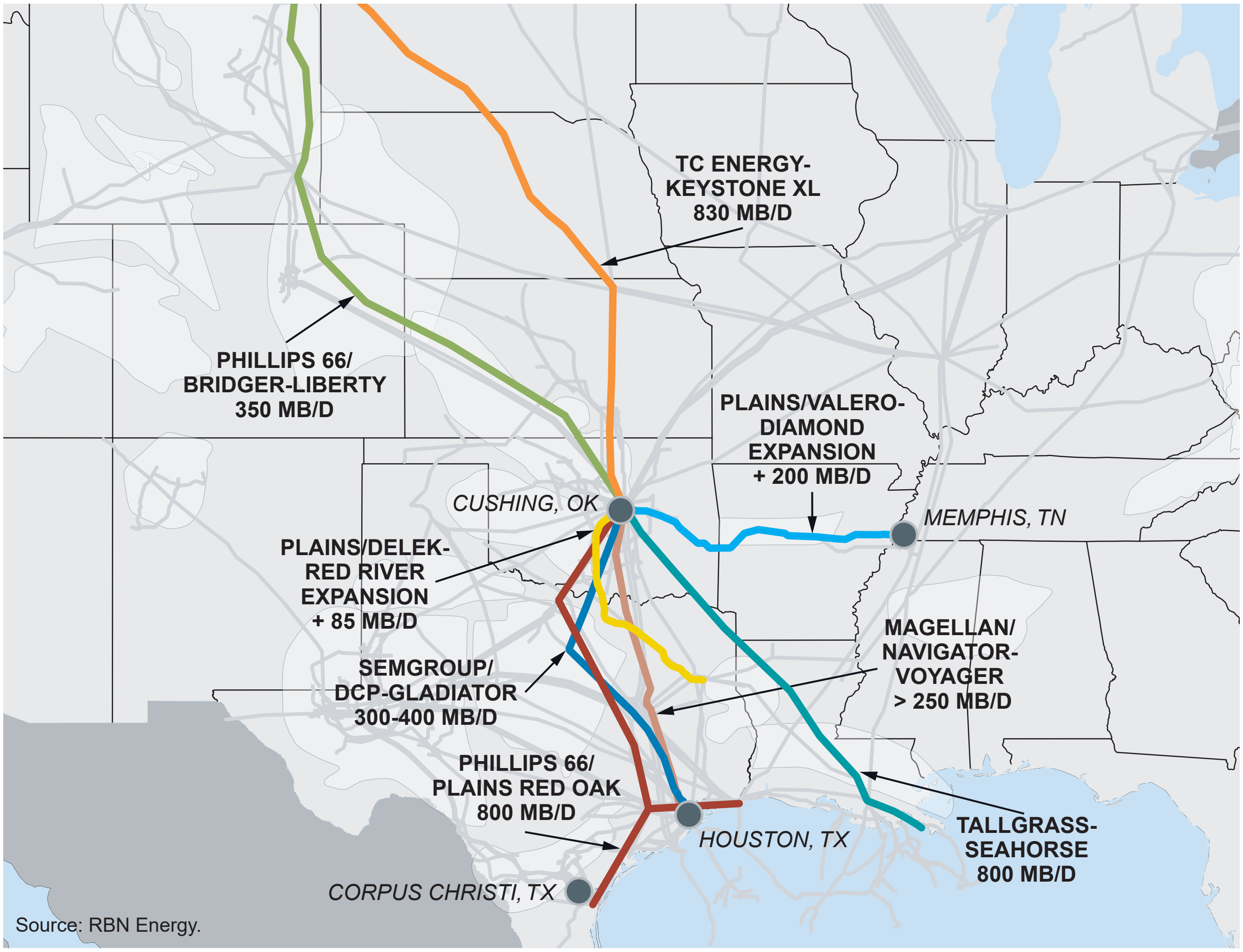


Figure 2-13. *Future Crude Oil Pipeline Buildout in the Midcontinent, 2019-2024*

the Permian Basin, which continued to experience outbound pipeline constraints.

Construction of pipelines that began before the price crash continued as planned. Four major projects out of the Permian Basin went into service during this period, adding 1,205 MB/D in pipeline capacity as depicted in Figure 2-15. The Permian Basin had sufficient crude oil takeaway capacity until the next period of constraints began in 2017.

l. Permian Basin Development (2017 to 2018)

Following a period of 3 years from 2015 to 2017 when the Permian Basin had adequate pipeline takeaway capacity, production began to again reach a level of potential constraints. Several projects were completed during this period, including the construction of new pipelines and the expansion of existing pipelines as depicted in Figure 2-16.

m. Permian Basin Development (2019 to 2021)

As crude oil prices recovered in 2018, Permian Basin crude oil production ramped up rapidly, growing from 2.5 MB/D in 2017 to 3.5 MB/D in 2018. By midyear 2018, Permian Basin crude oil prices were again almost $20/barrel under Cushing, due to oversupply in the basin and lack of takeaway capacity.

Various small pipeline expansions were implemented during late 2018 and early 2019, bringing

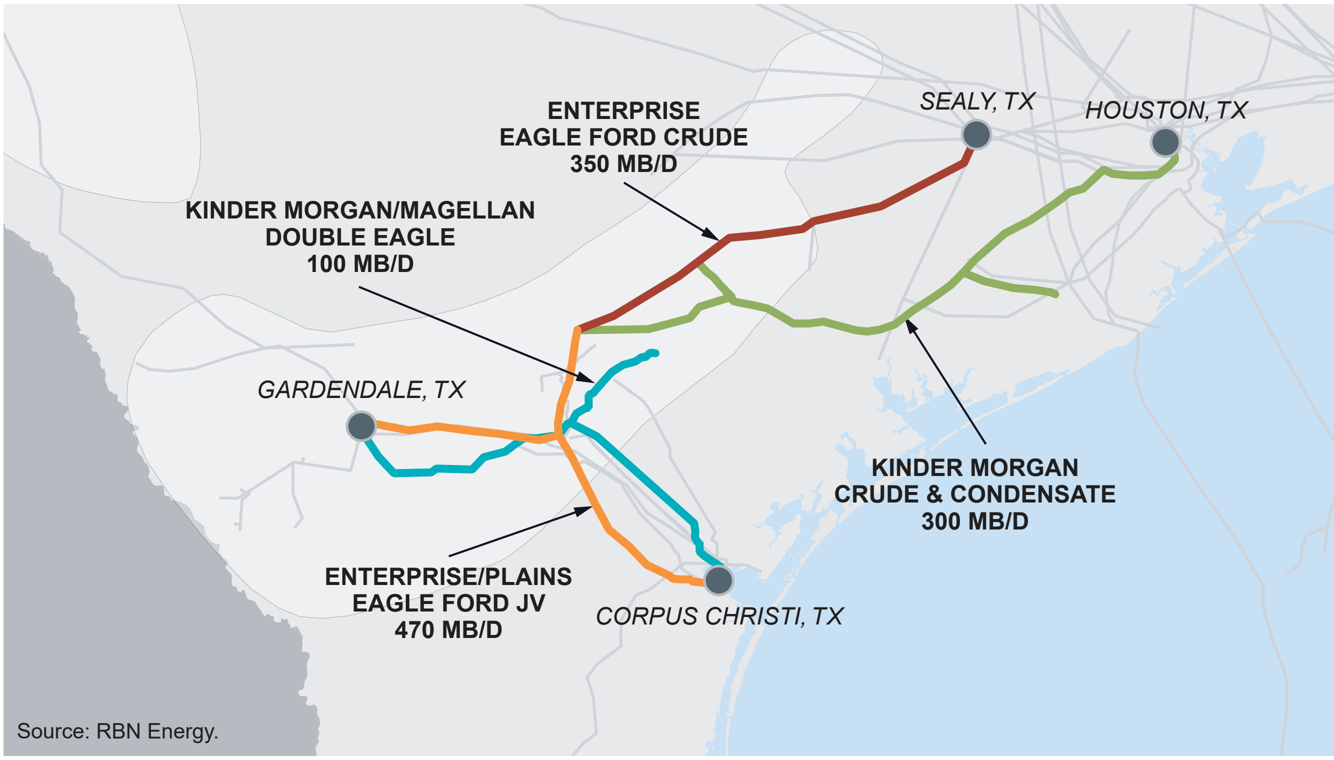


Figure 2-14. *Infrastructure Buildout in the Eagle Ford, 2010-2016*

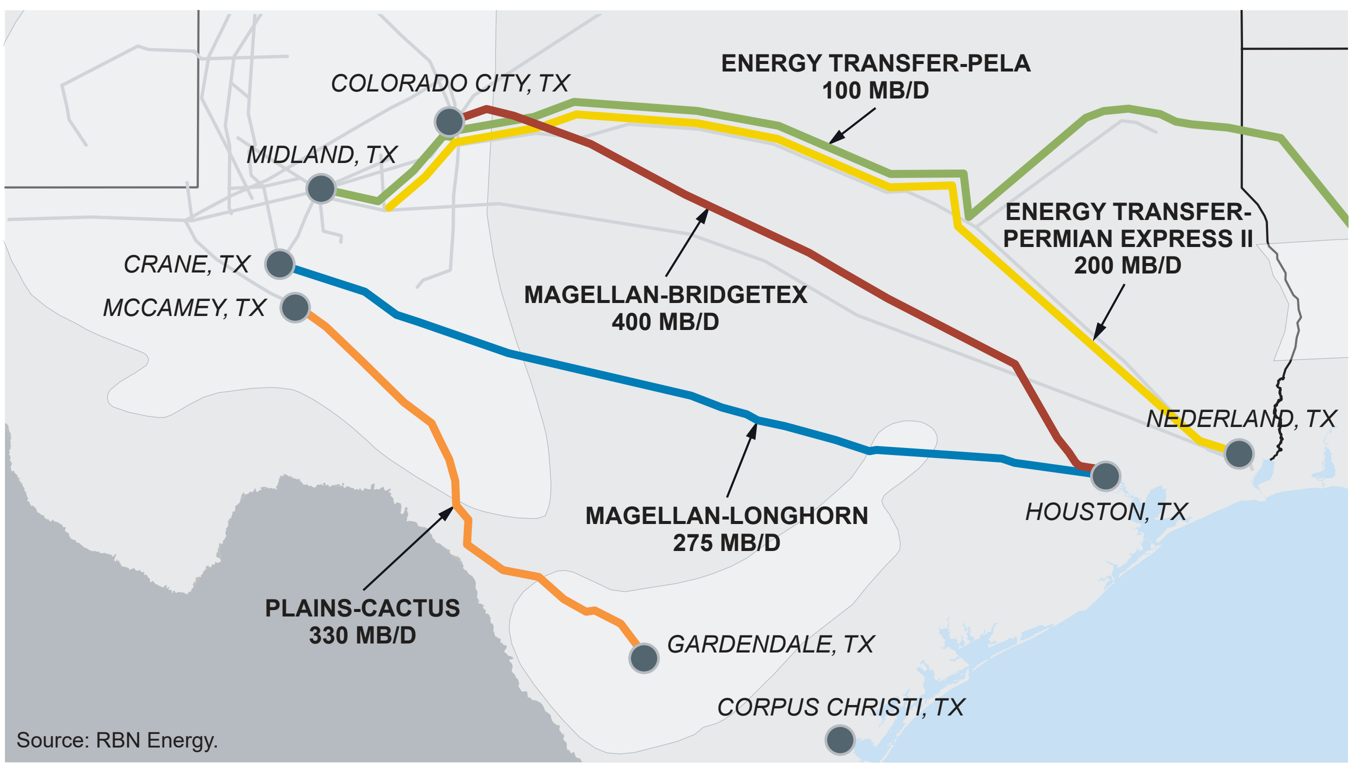


Figure 2-15. *Infrastructure Buildout in the Permian Basin, 2010-2016*

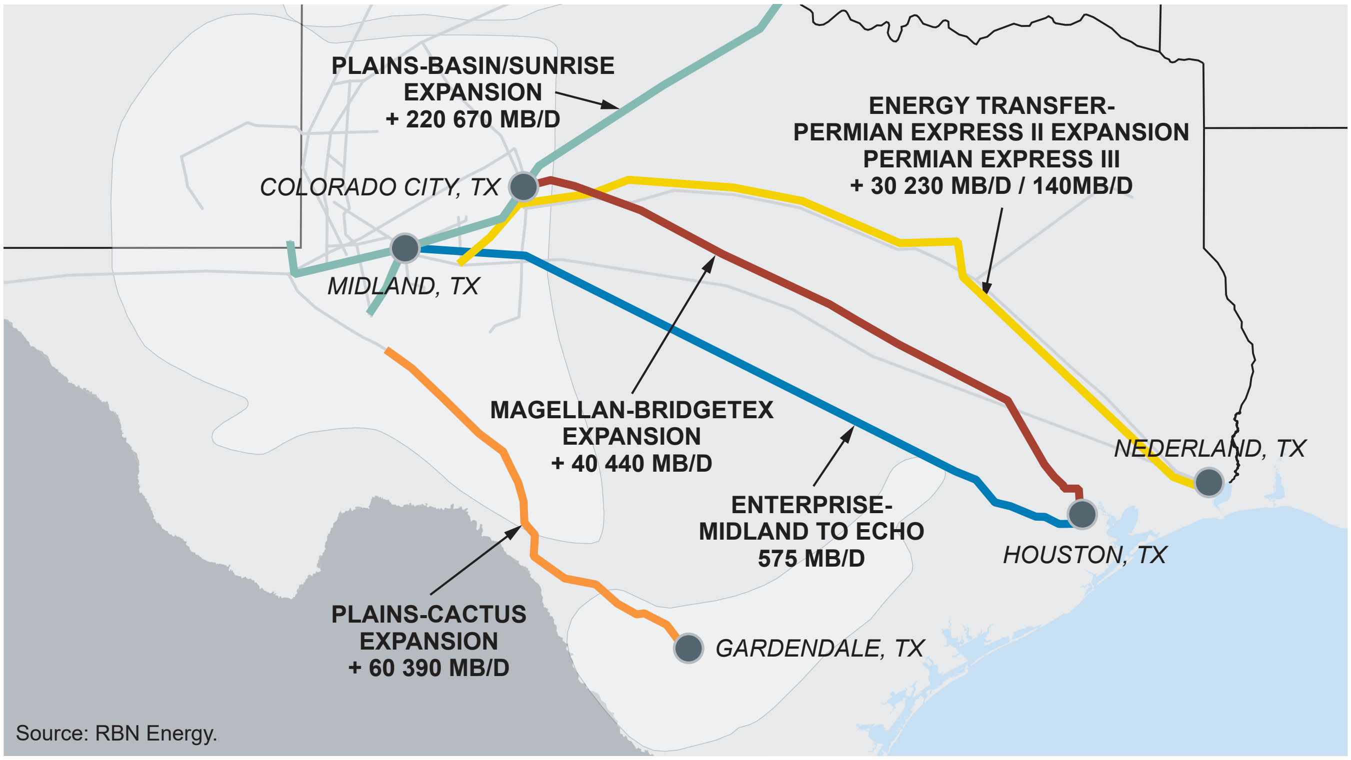


Figure 2-16. *Infrastructure Buildout in the Permian Basin, 2017-2018*

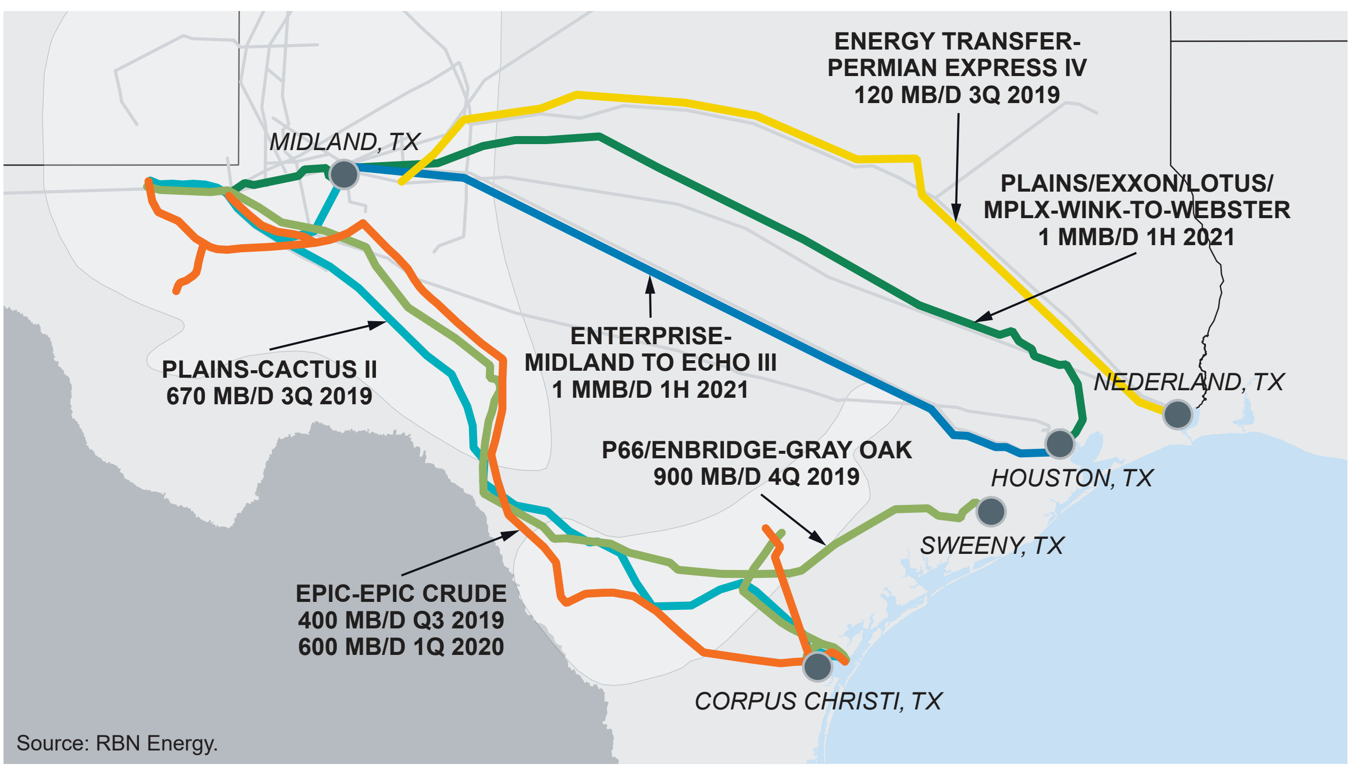


Figure 2-17. *Infrastructure Buildout in the Permian Basin, 2019-2021*

some relief to the basin. The Enterprise-Midland to ECHO II pipeline, originally an NGL pipeline, was also converted to crude oil service. Another 4.3 MMB/D of capacity is planned between the second half of 2019 and 2021, as depicted in Figure 2-17.

Supply growth in the Permian Basin has driven a large buildout of new transportation infrastructure. Since 2014, ~1.9 million barrels per day of new pipeline capacity has been placed into service. As of March 2019, greater than 3 million barrels per day of additional capacity is under construction. Virtually all of the new capacity will transport Permian Basin crude oil to market centers on the U.S. Gulf Coast, including Houston and Corpus Christi (Figure 2-18).

The evolution of oil pipelines from the Permian Basin demonstrates the market's ability to respond to supply changes, which increases infrastructure interconnectedness and ultimately, resiliency.

3. Exports — Crude Oil

Once the federal ban on crude oil exports to countries other than Canada was lifted in 2016, export activity ramped up rapidly. By utilizing existing ports where possible and reverse lightering in the Gulf of Mexico, the United States has managed to increase its crude oil exports from just under 500 MB/D when the export ban was lifted to nearly 3.5 MMB/D by mid-2019 (Figure 2-19). The ship-to-ship transfer process known as lightering refers to a larger vessel partially unloading onto a smaller vessel. Reverse lightering occurs when smaller vessels load onto a larger vessel.[9] This 3.0 MMB/D increase in crude oil exports has primarily gone to Asia and Europe.

The huge gains for U.S. crude oil production since 2010 have transformed the crude oil sector, sending the nation's oil output to the highest level of any other oil-producing country in the world. The production gains have primarily come in the form of light and super-light crude oil. This has been responsible for backing out nearly all light crude oil imports. Although U.S. refiners have been increasing their use of domestically sourced light crude oil supplies, most have reached the limits of how much they are able to use. With light and super-light crude oil production still growing, an oversupply has developed for these types of crude oil, resulting in their being exported in larger quantities. Existing export infrastructure along the Gulf Coast is being expanded alongside new export infrastructure projects to support this trend.

Current Gulf Coast capacity to export crude oil is about 5.1 MMB/D from terminals spread along the Texas and Louisiana coastlines, with the biggest concentration at terminals from Houston south in Corpus Christi and Freeport (Figure 2-20). Several of these terminals are not fully utilized today. Therefore, there is room for more export growth from existing terminals.

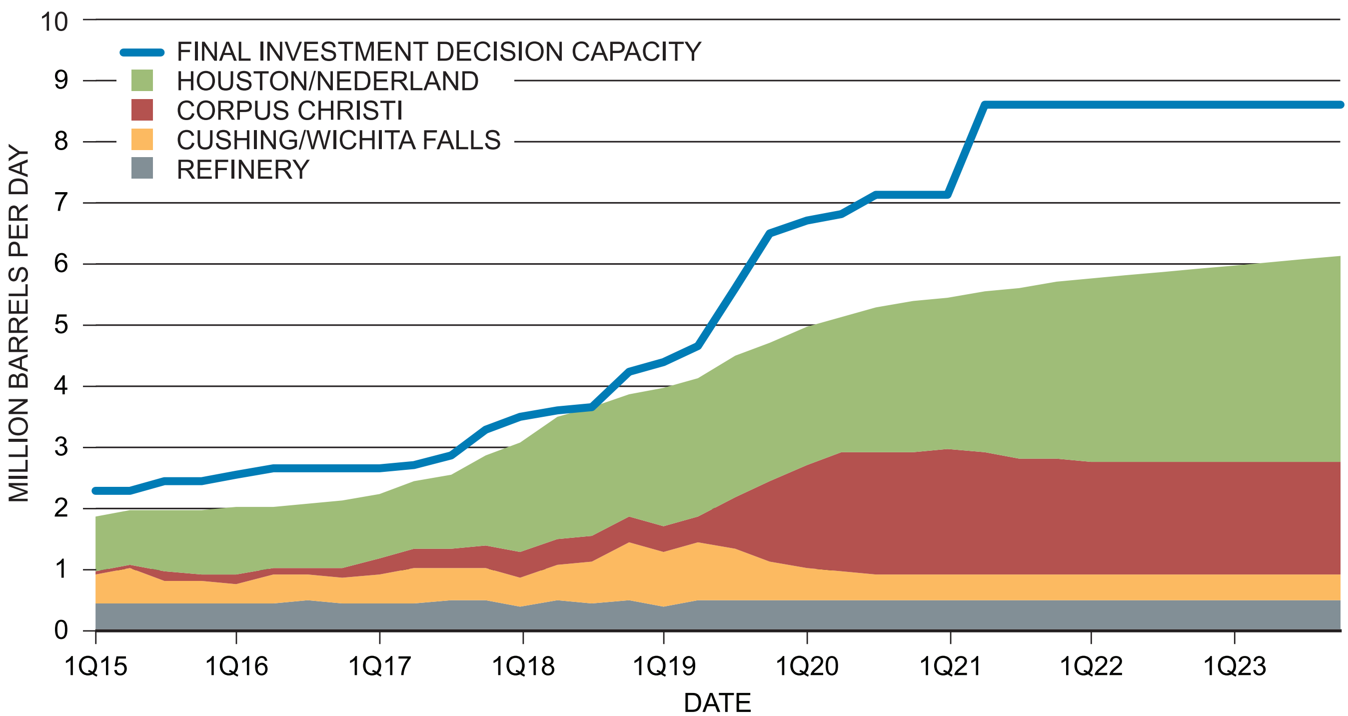
Multiple crude oil export projects are needed and being developed along the Texas and Louisiana coasts, amounting to as much as 13 MMB/D of prospective export capacity (Figure 2-21). Today, very large crude carriers (VLCCs) transport the majority of crude oil shipments around the world and can carry between 1.9-2.2 million barrels of crude oil.[10] No onshore Gulf Coast port currently is deep enough to handle fully laden VLCCs today. Many of the planned new terminals are offshore facilities that would have the capability to fully load VLCCs, which can carry roughly 2 million barrels each. Several onshore facilities are also planned to take advantage of a project to deepen and widen part of the Port of Corpus Christi ship channel to allow for VLCC traffic with drafts of up to 56 feet.

4. Resiliency — Crude Oil Transportation System

Each portion of the supply chain plays a pivotal role in providing increased resiliency through infrastructure interconnectedness. The more interconnected the infrastructure system is, the more resilient the system will be. The United

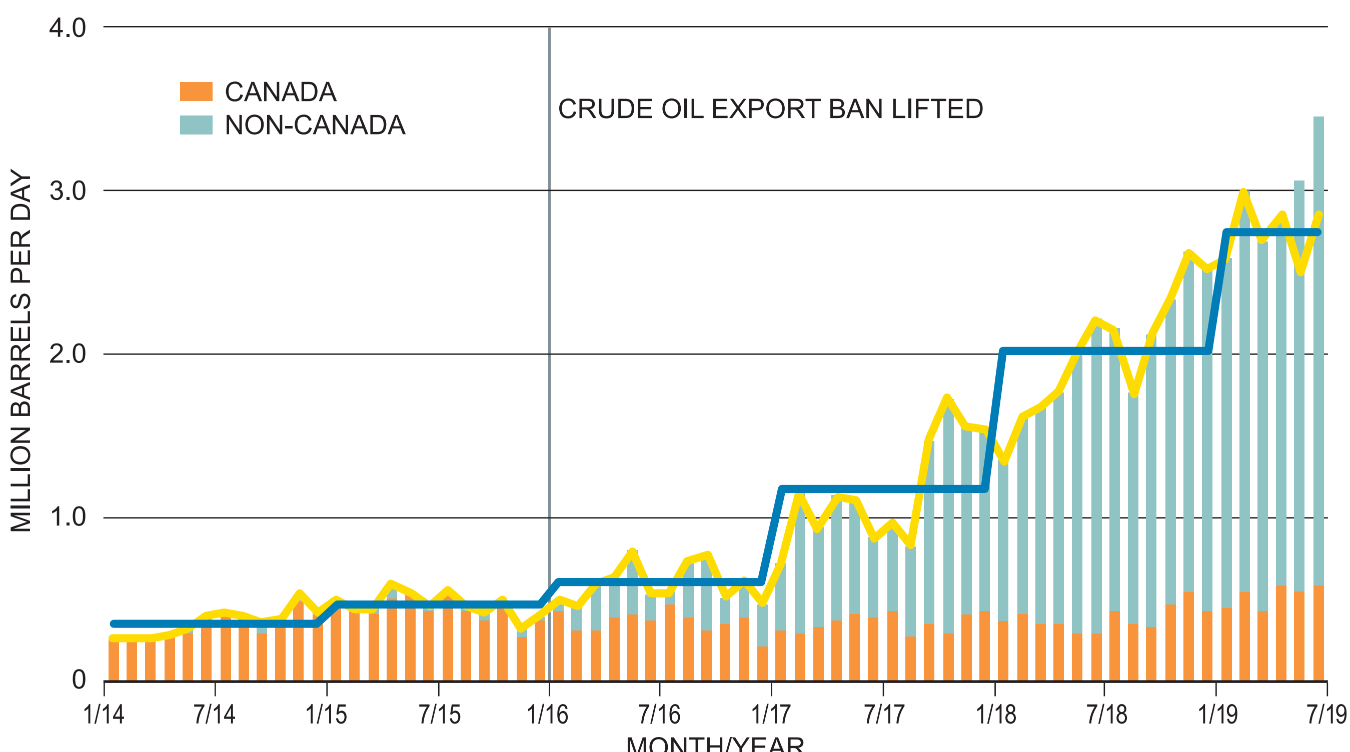
9 U.S. Energy Information Administration, "U.S. Gulf Coast Port Limitations Impose Additional Costs on Rising Crude Oil Exports," *Today in Energy*, May 16, 2018, https://www.eia.gov/todayinenergy/detail.php?id=36232 (accessed June 1, 2019).

10 U.S. Energy Information Administration, "Oil tanker sizes range from general purpose to ultra-large crude carriers on AFRA scale," *Today in Energy*, September 16, 2014, https://www.eia.gov/todayinenergy/detail.php?id=17991 (accessed October 28, 2019).



Source: East Daley Crude Hub Model.

Figure 2-18. *Permian Volumes by Destination*



Source: East Daley Crude Hub Model.

Figure 2-19. *U.S. Crude Oil Exports*

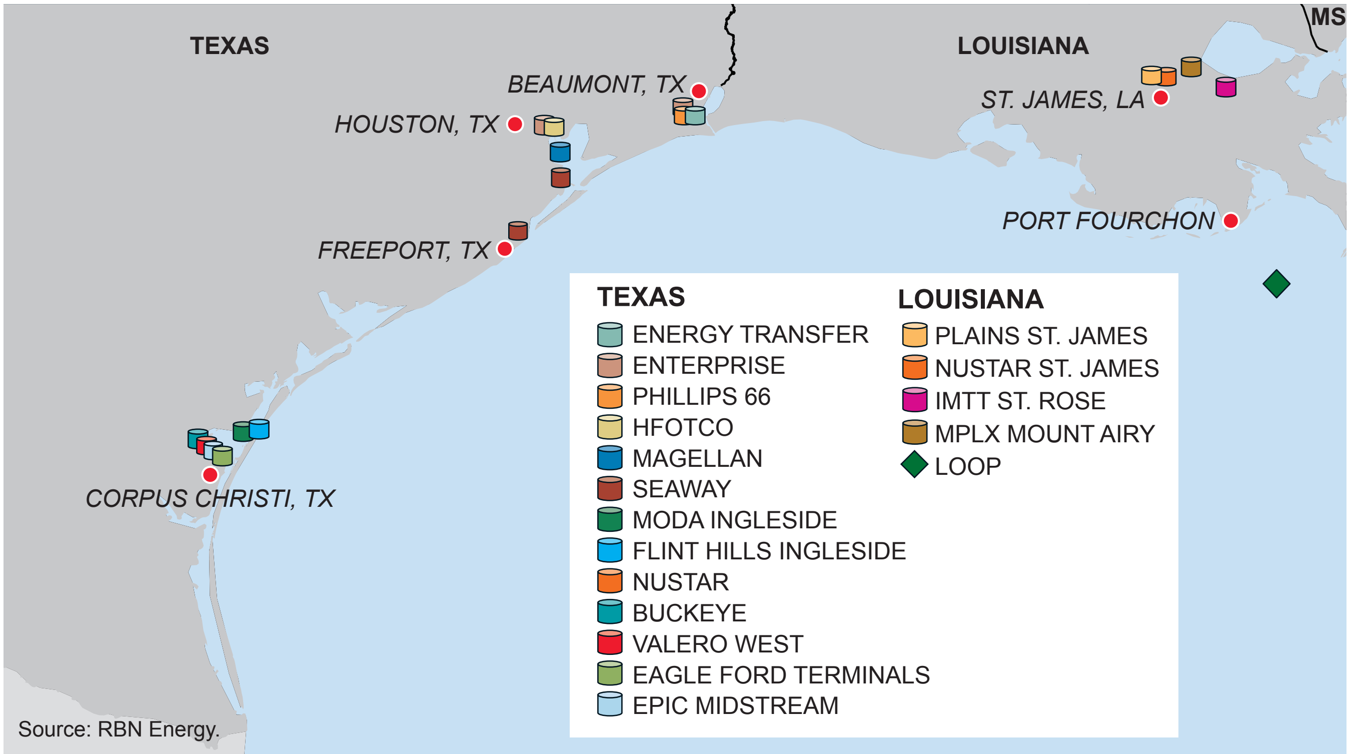


Figure 2-20. *Current U.S. Gulf Coast Crude Oil Export Terminals*

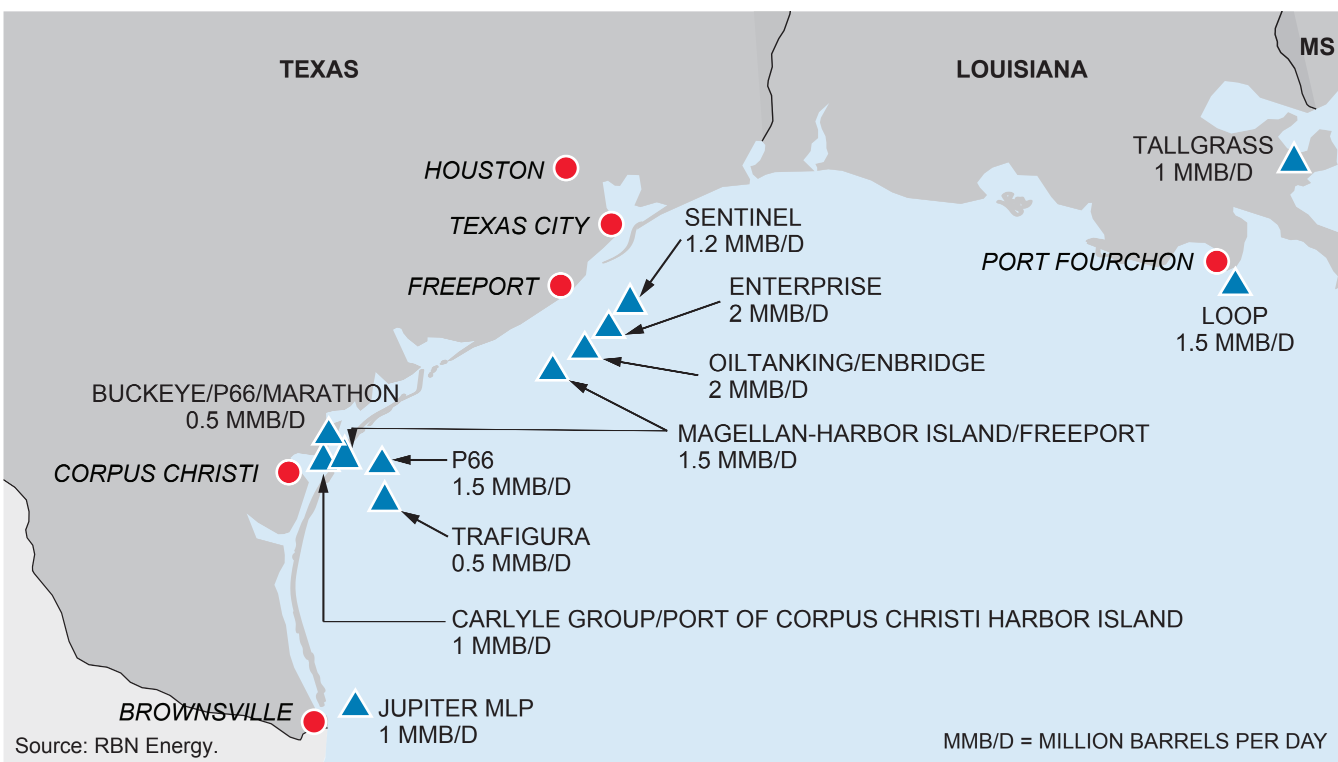


Figure 2-21. *Crude Oil Export Capacity Projected Additions*

States has a robust crude oil pipeline and railroad infrastructure system, which can transport crude oil to multiple destinations via various routes. This robust infrastructure within an area, such as the Gulf Coast, provides increased resiliency as there are pipelines, rail, trucks, and marine infrastructure that can be utilized to move crude oil to demand centers.

It is important to understand that resiliency is not static because supply and demand change over time. For this reason, U.S. crude oil resiliency needs to be consistently monitored.

Findings:

- Increasing domestic supply has allowed the energy transportation system to become more resilient as additional infrastructure is built to meet geographic changes in supply location as well as supply growth.
- Crude oil storage is essential to the supply chain, providing flexibility to adapt to fluctuations in supply and demand. Storage near demand centers provides the additional national and economic security that refineries can continue to run for a period of time in the event of a supply disruption upstream.
- The growth in U.S. oil supplies has reduced the influence of overseas producing nations on the U.S. economy and has contributed to the diversity of global supply. All of this could not have come about without the significant buildout in infrastructure that has allowed the abundance of shale oil to reach markets domestically and internationally.

C. Refined Products Infrastructure History and Current State

1. General Overview of Refining Systems

Oil refineries play a critical role in the U.S. energy market. Refining oil is an industrial process where crude oil is transformed and refined into more useful products, such as fuels for transportation and heating, asphalt for paving roads, petroleum coke for high-British thermal units (BTU) cement kilns and chemical feedstocks. Petroleum refineries are complex and selectively configured based on the physical characteristics of the crude oil and the desired product output. The ability to reliably convert raw crude oil to refined products for consumption greatly influences the resiliency of the system.

a. Capacity and Utilization

As of January 1, 2019, there were 135 operable petroleum refineries in the United States with an operable capacity of 18.6 MMB/D, essentially flat since the beginning of 2017.[11] Figure 2-22 shows that operable capacity has steadily increased by 0.9 MMB/D net since 2009, and utilization has also increased from 83% to 93% during the same period.[12]

High utilization is preferred for operational and economic efficiency, but high utilization can be seen as a concern when viewed from the perspective of energy resiliency. With minimal slack in the system, loss of capacity can be significant and create cascading constraints on upstream production. Two mitigations to capacity risk are storage and exports. In the event of refining capacity loss, refined product storage can be drawn to meet domestic demand. Similarly, export of refined products can be reduced in to maintain storage volumes until capacity is restored. The EIA currently projects a peak of 96% utilization in 2020 followed by long-term expectation of 90% to 92%. This forecast assumes capacity expansion of 0.4 MMB/D, for a total of 19 million MMB/D. U.S. refinery utilization peaks in most forecast scenarios in 2020.

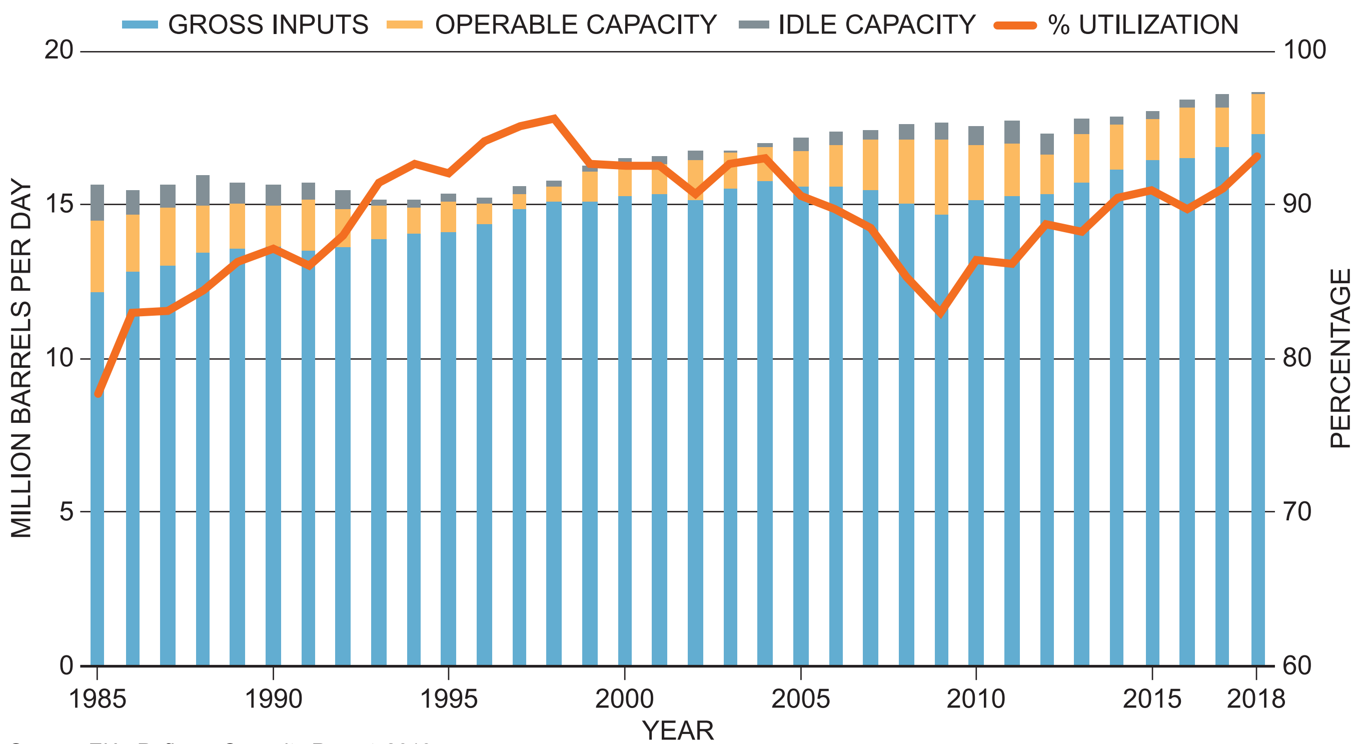
b. Feedstock Quality Specifications and the Importance of Global Trade

In the past 10 years, refinery inputs have increased from 14.7 MMB/D to 17.3 MMB/D. In 2018, refinery inputs were approximately 64% sourced from domestic production, compared to only 37% in 2009 (Figure 2-23).[13] In 2018, U.S.

11 U.S. Energy Information Administration, "Number and Capacity of Petroleum Refineries," Petroleum & Other Liquids, https://www.eia.gov/dnav/pet/pet_pnp_cap1_dcu_nus_a.htm (accessed June 1, 2019).

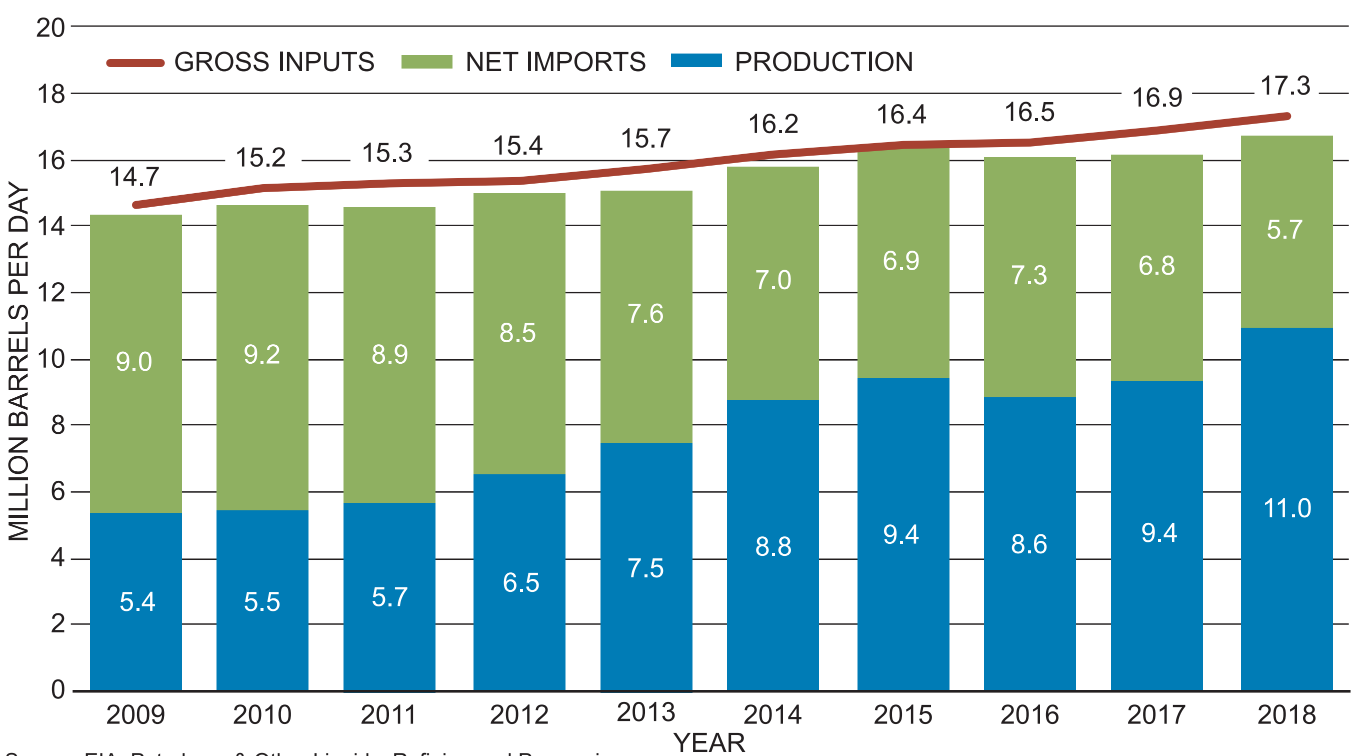
12 Ibid.

13 U.S. Energy Information Administration, "Refinery Receipts of Crude Oil by Method of Transportation," Petroleum & Other Liquids, https://www.eia.gov/dnav/pet/pet_pnp_caprec_dcu_nus_a.htm (accessed June 1, 2019).



Source: EIA, *Refinery Capacity Report*, 2019.

Figure 2-22. *Refining Capacity and Utilization*



Source: EIA, Petroleum & Other Liquids, Refining and Processing.

Figure 2-23. *U.S. Crude Oil Production, Net Imports, and Gross Inputs to Refineries*

Gulf Coast crude oil production set a record of 7.1 MMB/D. This increased production is mostly of light, sweet crude oils, but most Gulf Coast refineries are configured to process heavy, sour crude oils. This increasing production and mismatch between crude oil type and refinery configuration necessitates the need for increased exports.

Conversely, Gulf Coast refiners still require imports of heavy sour crude oil to maximize economics and produce a slate of heavier, more complex refined products. Imports have been reduced in favor of abundant regional light sweet crude oils, but refiners are likely to continue using heavy sour imports as they adjust refining processes to maximize output and profits under market prices. It should be recognized that the ease and optionality of obtaining the necessary feedstock through global trade (including supply from Canada and Mexico) to supply refineries enables resiliency.

A typical light sweet shale crude oil produces a greater proportion of petrochemical feedstocks and gasoline components. This presents a challenge, since the yield of gasoline from a refinery is expected to grow at a time when U.S. domestic gasoline demand growth is stalling. Refiners may not add incremental refining capacity in this environment, and therefore, light crude oil volumes that do not find space in U.S. refineries will have to be traded in the global market. On the other hand, the attractiveness of light sweet shale crude oil and the abundance of natural gas has led to significant growth in petrochemical projects across the country. This will be further described in Section V, The Value of Infrastructure, later in this chapter.

Secondary refining capacity downstream of the crude oil distillation unit, including thermal cracking, catalytic hydrocracking, and hydrotreating and desulfurization, increased 1% from 2016 to 2017. These upgrades primarily serve to increase the value of refinery outputs or provide regulatory compliance rather than adding new capacity. Expansions and/or reconfiguration of existing refineries are more likely to be seen than new construction going forward. It is recommended that legislators and federal and state regulators support permitting efforts of refiners to adapt to these rapidly changing supply and demand dynamics.

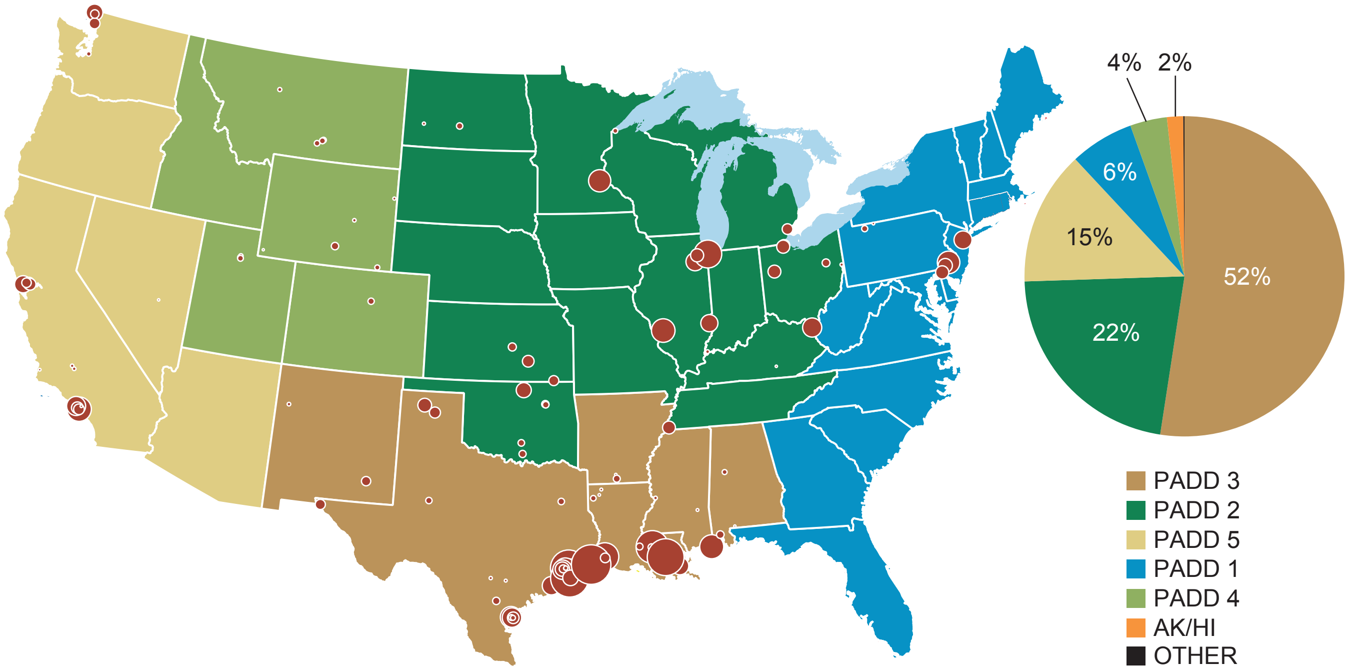
c. Geographic Concentration

Figure 2-24 shows that just over 50% of existing capacity is located on the Gulf Coast (PADD 3).[14]

- The geographic concentration of the U.S. refining capacity is both a strength and a weakness: oil is the largest single commodity in global trade, and therefore refineries realize market advantages by being near navigable waterways. This characteristic of the refining industry is one of the key enablers during the United States' shift from a net importer to a net exporter of oil. Gulf Coast refineries have been able to maintain high capacity utilization as the supply basins have shifted over time.
- Many refiners can take advantage of multiple modes of transportation including pipeline, tanker, barge, rail, and truck. Through an intricate and extensive network of pipelines, refiners can meet the needs of multiple markets and respond more rapidly to system disruptions.
- The Gulf Coast region also provides operational efficiencies and market advantages to refiners who can supply intermediate and finished products to high demand users such as petrochemical plants through existing infrastructure network.
- A vulnerability of refineries on the Gulf Coast is the exposure to catastrophic weather events. This region has experienced multiple powerful storms in recent history, testing the emergency response systems and the ability of refiners to recover after each storm. Hurricanes Ike, Rita, and Harvey have highlighted just how important Gulf Coast refining and associated infrastructure are to the nation. Each of these storms has temporarily shut down more than half of the total Gulf Coast refining capacity. An analysis by RBN Energy (Figure 2-25) indicates that after Hurricane Harvey capacity was restored to pre-storm levels within 3 weeks and resulted in a loss of 60 million barrels, or 3.5 days of supply.[15]

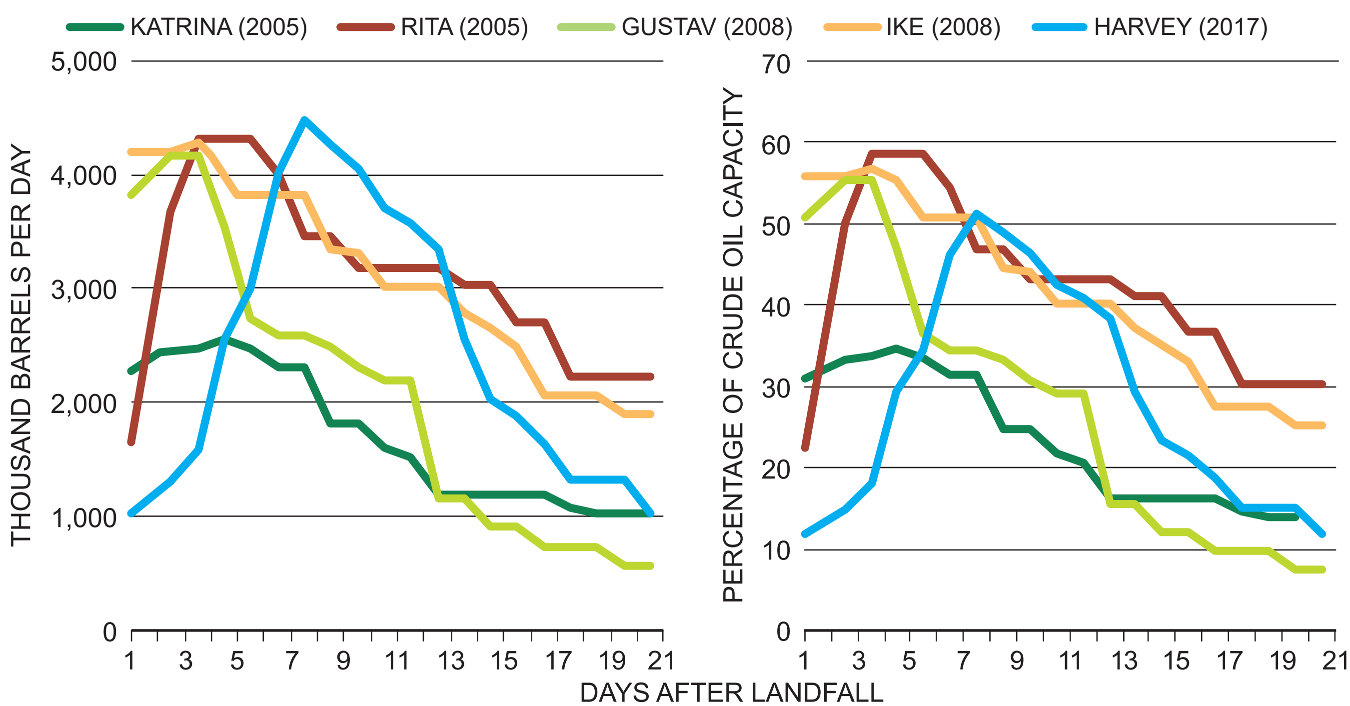
14 As of January 1, 2018, total refining capacity was 18.6 million barrels per day.

15 Baker and O'Brien (Kalt, A.), "After the Storm, Part 3 — Hurricane Harvey and the Importance of Gulf Coast Refined Product Infrastructure," RBN Energy.com, September 18, 2018, https://rbnenergy.com/after-the-storm-part-3-hurricane-harvey-and-the-importance-of-gulf-coast-refined-product-infrastructure.



Source: EIA, Petroleum & Other Liquids, Refinery Capacity Report.

Figure 2-24. *U.S. Refining Capacity by PADD*



Source: Baker and O'Brien (Kalt, A.), "After the Storm, Part 3 – Hurricane Harvey and the Importance of Gulf Coast Refined Product Infrastructure," RBN Energy.

Figure 2-25. *Refining Capacity Offline Due to Hurricanes*

These events have demonstrated the magnitude of exposure to extended, unplanned outages and the cascading disruption to the crude oil and petroleum product supply chains. While we cannot prevent hurricanes from hitting the Gulf Coast, there are multiple efforts ongoing to mitigate the impacts of future storms. For example, refiners and pipeline companies have worked with utilities to ensure priority electrical restoration and many have secured back-up power generation. Many facilities have improved flood prevention by installing dikes, and others have adjusted storage levels to ensure available supply to high demand centers in the event of a supply disruption. While these efforts mitigate the cascading impacts of catastrophic events like storms, the fact remains that geographic concentration of refineries is a vulnerability and threat to resiliency. It is recommended that legislators and regulators support policies that protect Gulf Coast refineries and infrastructure—critical components of the nation's energy system and economy.

d. Impact of Regulations on Refiners

Changes in regulations for environmental emissions and product specifications often require investment for new equipment and process modifications for refiners to achieve compliance. The most recent example of regulatory change is the International Maritime Organization (IMO) 2020, a new regulation that reduces the sulfur content of maritime bunker fuel from 3.5 to 0.5% to reduce sulfur dioxide emissions. The international standard will affect refining operations as refiners and marine transporters adapt to meet the requirements of IMO 2020. Refiners are evaluating long-term price impacts of the new standards on crude oil and refined products to understand whether they should invest in upgrading facilities to reduce their production of high-sulfur fuel oil, or simply change their crude oil slate and/or fuel oil blending. Please refer to the IMO 2020 Topic Paper for further discussion on this topic. Depending on industry response to the new regulations, there is potential to increase or decrease the availability of refining capacity and impact resiliency. A potentially higher risk outcome would be if import or export capacity is reduced and cascading constraints are imposed on refiners and on all upstream product streams.

Refiners encountered similar impacts from legislation with the 1990 Clean Air Act (CAA), which enacted federal laws that regulate air emissions from stationary and mobile sources and authorized the Environmental Protection Agency to regulate emissions standards. Compliance with the CAA provisions required refiners to modify, design, permit, and construct new units to produce mandated transportation fuel quality specifications. Refiners who were unable to economically comply with the standards stopped producing, and thereby removed capacity and resiliency from the refining system.

2. General Overview of Transportation System

In the United States, refined fuels[16] are delivered to end users via an extended and interconnected network of pipelines, rail, marine vessels, trucks, and storage terminals. Pipelines are the primary mode of transportation to move refined fuels throughout the country, accounting for 68% of the barrels transported in 2017.[17] Marine vessels accounted for 20% of transportation in 2017, with rail moving 12%.[18]

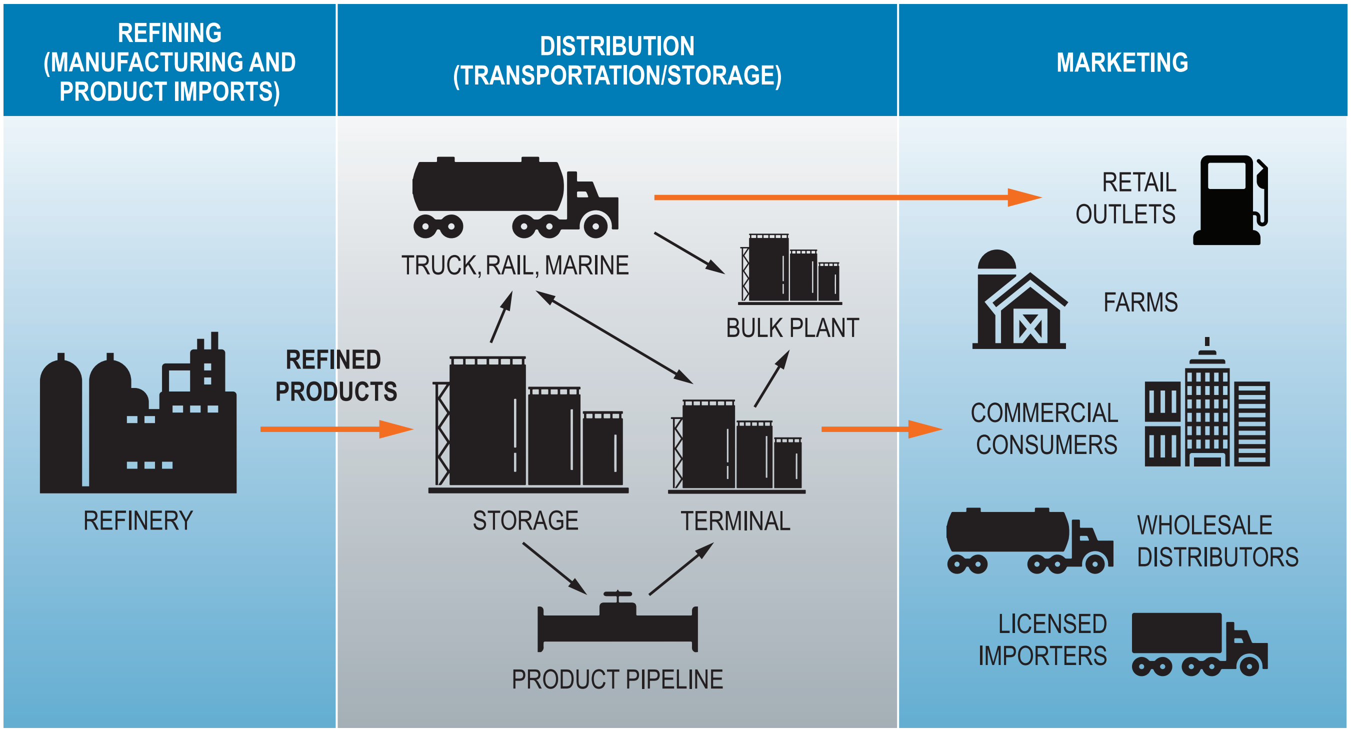
Refined fuels are transported from petroleum refineries utilizing pipelines and moved to storage terminals throughout the country. From these storage terminals, the product can be further distributed to another facility via pipeline, loaded into rail cars for further distribution, loaded into barges/tankers on a waterway, or loaded as a finished fuel into a truck for final distribution. The final destination for refined fuels can range anywhere from a retail station, energy production facility, industrial plant, or residential home depending on the quality of the product. This value chain is depicted in Figure 2-26.[19]

16 Refined fuels in this chapter includes gasoline, diesel fuels, and jet fuel.

17 Bureau of Transportation Statistics, "Crude Oil and Petroleum Products Transported in the United States by Mode," https://www.bts.gov/content/crude-oil-and-petroleum-products-transported-united-states-mode (accessed July 29, 2019).

18 Ibid.

19 Canadian Fuels Association, "Picture this: How fuel gets from the refinery to your gas pump," March 30, 2017, https://www.canadianfuels.ca/Blog/2017/March-2017/Picture-this-How-fuel-gets-from-the-refinery-to-your-gas-pump/.



Source: Canadian Fuels Association.

Figure 2-26. *Downstream Sector Value Chain*

Refined fuel storage assets are critical to the ability to move the product efficiently throughout the system. These assets are commonly used for operational purposes to gather barrels in order to build a large enough batch cycle to move to the next destination along the pipeline. Additionally, these storage assets can be used by refined fuel traders to develop storage positions based on price arbitrage opportunities, or by retailers and refiners for security of supply. The refining industry will commonly use these storage facilities to build inventory ahead of planned maintenance to ensure they maintain a presence in the marketplace. The retail industry will use this storage to ensure supply resiliency amid a sudden change in the supply market.

3. History and Current State

Historically, refined fuels pipelines were built out of necessity to meet growing demand driven by the growth of the automobile industry in the 1920s and the migration of the population across the United States. In the 1930s, the first refined products pipelines were built to move products from the refining center in Chicago, Illinois to demand centers in St. Louis, Missouri, and Kansas City, Missouri. Then in 1942, War Emergency Pipelines, Inc. was formed as a consortium of America's largest oil companies at the time, to begin building the 1,200-mile Little Big Inch, which is now the Enterprise TEPPCO pipeline (Figure 2-27); see also text box "Vignette: Oil Infrastructure Helps Win World War II." This pipeline was constructed to move products from Texas refineries to as far east as Philadelphia and New York. The project was initially meant to supply the fuel needs during the war effort; however, when multiple oil tankers were sunk off the East Coast of the United States in 1945, there was a large movement to land-based pipelines. During that same period, Buckeye Pipelines began building transportation fuel lines and converting idle crude oil pipelines in Ohio and Indiana to supply the growing demand for transportation fuels. Later in 1962, eight oil companies (Sinclair Pipeline, Texaco, Gulf Oil, American Oil, the Pure Oil Co., Phillips Petroleum Co., the Cities Service Co., and Continental Co.) founded the Colonial Pipeline to transport transportation fuels from the Gulf Coast to the Southeast and East Coast destinations. At the time, the Colonial Pipeline

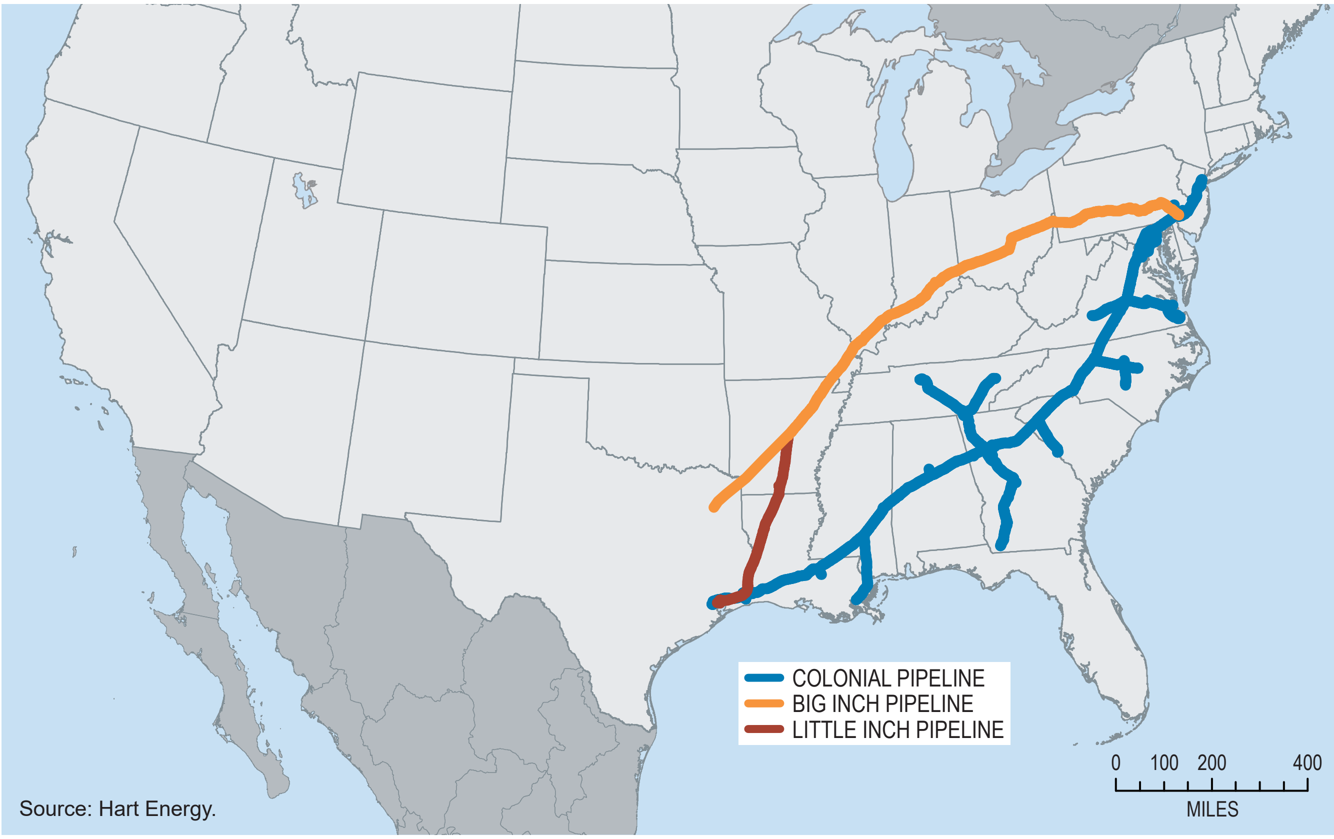


Figure 2-27. *Big Inch, Little Inch, and Colonial Pipelines*

was the largest privately financed pipeline construction project in U.S. history.

VIGNETTE: OIL INFRASTRUCTURE HELPS WIN WORLD WAR II

According to the American Oil & Gas Historical Society, two 1943 pipelines from Texas to the East Coast helped win World War II. Big Inch carried crude oil from East Texas to Illinois, while Little Big Inch carried gasoline, heating oil, diesel, and kerosene all the way to Philadelphia and New York. The pipelines, both completed before the D-Day invasion at Normandy on June 6, 1944, made possible the delivery of huge quantities of oil and refined products for Operation Overlord. This was an excellent example of strong government/public cooperation. The pipelines are both operational today, albeit in different services.

Refined products pipelines are built to solve a supply/demand imbalance. Due to the initial cost and time to build a pipeline, other transportation modes such as trucking, rail, and marine movements will precede the pipeline construction. When the imbalance of supply/demand gets to a point where a pipeline can be built to deliver the transportation of refined fuels more efficiently than other modes and the economics of the build are supported, a pipeline project is commenced. Multiple transportation modes will continue to coexist to solve short-term supply/demand disruptions and deliver to markets that are difficult to serve by way of pipeline due to geographical obstacles and governmental permitting regulations.

Interstate and intrastate pipelines transport refined products to demand centers from refineries throughout the country, which are typically referred to by their PADD name.[20] An overview of the 5 PADDs (Petroleum Administration for Defense Districts) is depicted in Figure 2-28.

20 U.S Energy Information Administration, "PADD regions enable regional analysis of petroleum product supply and movements," *Today in Energy*, February 7, 2012, https://www.eia.gov/todayinenergy/detail.php?id=4890 (accessed July 31, 2019).

Figure 2-29 shows some of the major pipelines that move product from refineries to terminals, other pipelines, and other consumer markets. These pipeline networks are crucial to supplying the national demand for gasoline, diesel fuels, and jet fuel. Today, refined products pipelines stretch 62,491 miles across the United States.[21]

Movement of transportation fuels between the Gulf Coast and East Coast represents the largest movement of such products in the United States and primarily move out of the region by pipeline. In most cases, refined products pipelines utilize one pipeline to transport multiple grades of fuel.

21 Pipeline and Hazardous Materials Safety Administration, "Mileage for Hazardous Liquid or Carbon Dioxide Systems," Annual Report, https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-hazardous-liquid-or-carbon-dioxide-systems (accessed October 1, 2019).

Without a buffer in between the fuels, this process is called batching. These pipelines typically ship segregated batches of products, as illustrated by Figure 2-30.

These areas are generally served by the major pipeline systems described here:

- The Colonial and Plantation pipelines deliver fuels from the Gulf Coast throughout markets in the Midwest and East Coast. These pipelines have a combined capacity of 3.2 MMB/D. Colonial also interconnects with the Buckeye and Sunoco Logistics systems that move product within PADD 1 (East Coast).
- The Magellan system is the longest refined products system extending from the Gulf Coast and covers 15 states. It can access refinery capacity

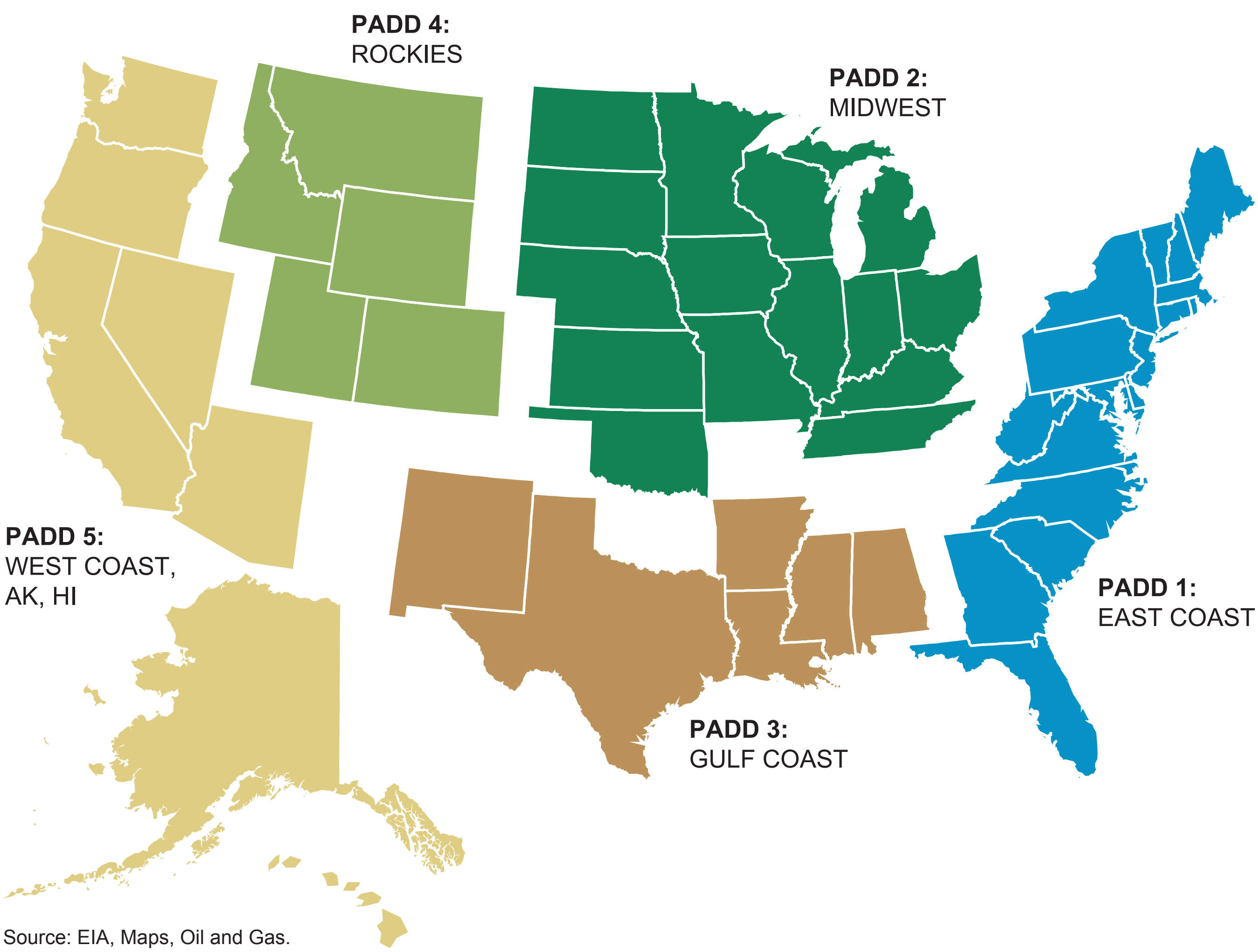


Figure 2-28. *Map of PADD Regions*

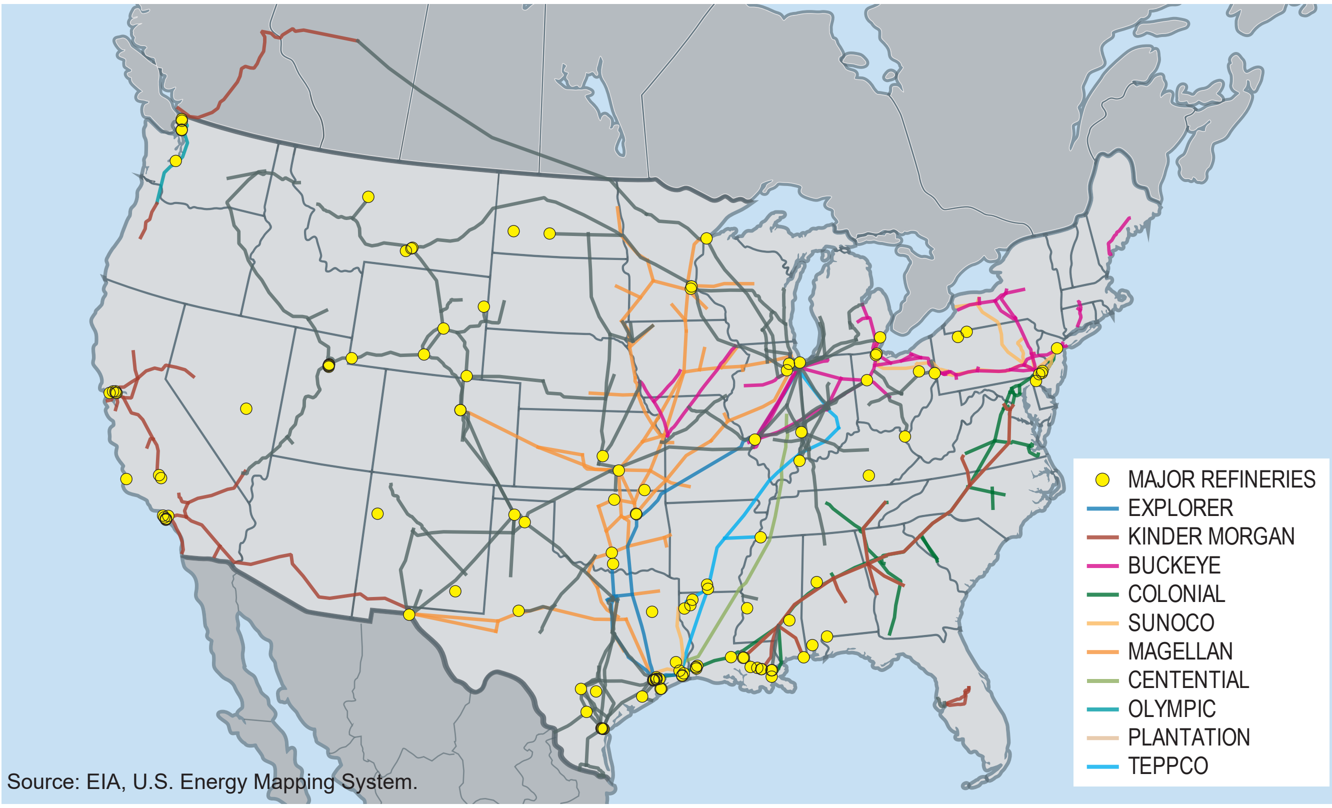
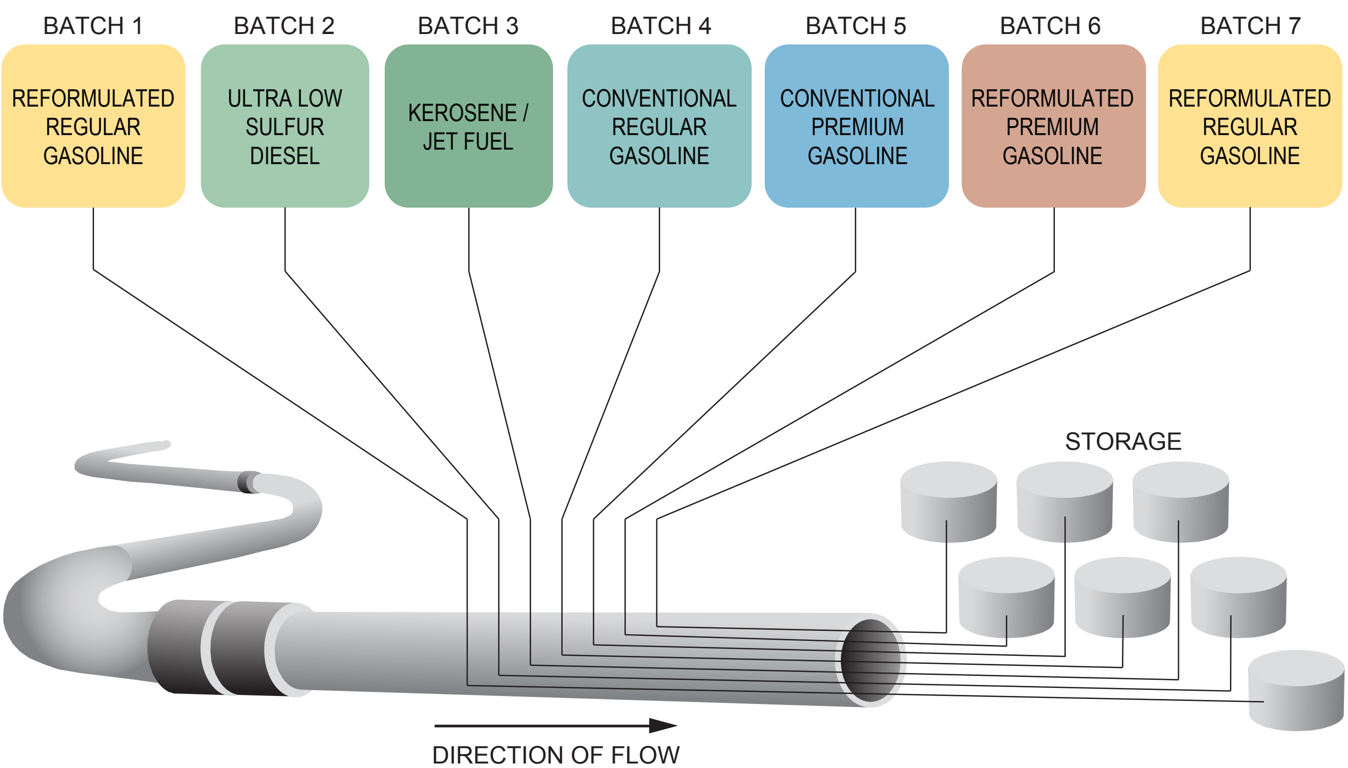


Figure 2-29. *Map of Major Refined Products Pipelines and Refinery Locations*



Source: Pipeline 101.

Figure 2-30. *Petroleum Products Batching* in the midcontinent and Gulf Coast and is one of the key systems internal to PADD 2 (Midwest).

- The Explorer pipeline originates in the Texas Gulf Coast and supplies markets in the Texas inland region and markets throughout the Midwest. The Explorer pipeline is a large-diameter pipe ranging from 28" to 24", telescoping as it delivers product to midpoint destinations along its path.

There are a number of regions in the United States where no refined products pipelines operate, such as New England and Florida. In other regions, such as PADD 5 (West Coast, Alaska, Hawaii), there are only a few pipelines. Kinder Morgan's Calnev pipeline transports gasoline, diesel, and jet fuel from Los Angeles to Las Vegas. This pipeline system serves the McCarran International Airport as well as the Nellis and Edwards Air Force bases and is a supply source for jet fuel to Las Vegas. Another pipeline, the UNEV line from Salt Lake City moves gasoline and distillate to Las Vegas. The Olympic pipeline is a products pipeline to Portland. The Kinder Morgan East and West supply fuels to Arizona.

As discussed in the Supply and Demand chapter, gasoline and distillate demand are forecast to remain flat or decline. As such, existing infrastructure should be sufficient to accommodate volumes. Jet fuel demand, however, is forecast to increase. Product lines typically run at capacity and more infrastructure may be needed.

a. Large-Diameter Pipelines for Inter-PADD Movements

Large-diameter pipelines that range from 18" to 36" in diameter are generally used to transport product between PADDs. Examples of these pipelines are Colonial, Plantation, Magellan, and Explorer, which were described previously. These pipelines solve significant regional supply/demand imbalances, much like in PADD 3 (Gulf Coast) where more than 50% of U.S. refining capacity resides. PADD 3 (Gulf Coast) is the main source of supply for PADD 1 (East Coast), which is home to approximately one-third of the United States demand for transportation fuels. The Explorer pipeline is another large-diameter pipeline that was originally built to transfer transportation fuels from PADD 3 (Gulf Coast) into PADD 2 (Midwest). The flows from PADD 3 (Gulf Coast) are illustrated in Figure 2-31. The Explorer pipeline was built at a time when PADD 2 (Midwest) was in a significant need of supply to meet growing demand in the region. Since then, refinery utilizations have increased to a point of making PADD 2 (Midwest) almost neutral on intra-PADD supply/demand. This has allowed Explorer to focus on other liquid fuels and fuel additives. Additionally, these larger-diameter pipelines are used to connect local refineries with marine export terminals along the Gulf Coast. These export facilities provide storage tanks for the owners of the products to accumulate additional product in tankage, facilitate buy/sell transactions, and import/export product to and from the region. A significant amount of PADD 1 (East Coast) demand (~11%) is delivered via these Gulf Coast and Louisiana Coast terminals using Jones Act vessels.

The Jones Act, federal statute 46 USC Section 55102, controls coastal trade within the United States. The Jones Act prohibits foreign built or foreign flagged vessels from delivering goods into a U.S. port that originated from another U.S. port.

b. Small-Diameter Pipelines for Inter-PADD and Intra-PADD Movements

Small-diameter pipelines that range from 6" to 16" in diameter are generally used to transport product within each PADD to distribute transportation fuels from refineries to the major demand centers within the region. Originally, many of these pipelines were built by companies, or a consortium of companies, who owned smaller local refineries to supply the demand within their local market. As PADD 2 has seen a significant portion of the original refineries idled over time (54 operating refineries in 1982, down to 25 in 2019), these smaller diameter pipelines are now being used to solve further-reaching supply/demand imbalances. The key benefit of these pipelines is the ability to easily reverse flow as needed to supply the market's needs. These reversals can happen daily, quarterly, or as seasonal supply/demand for the different transportation fuels dictate. The limited amount of line fill (amount of product held in the line at any one time) compared to a large-diameter

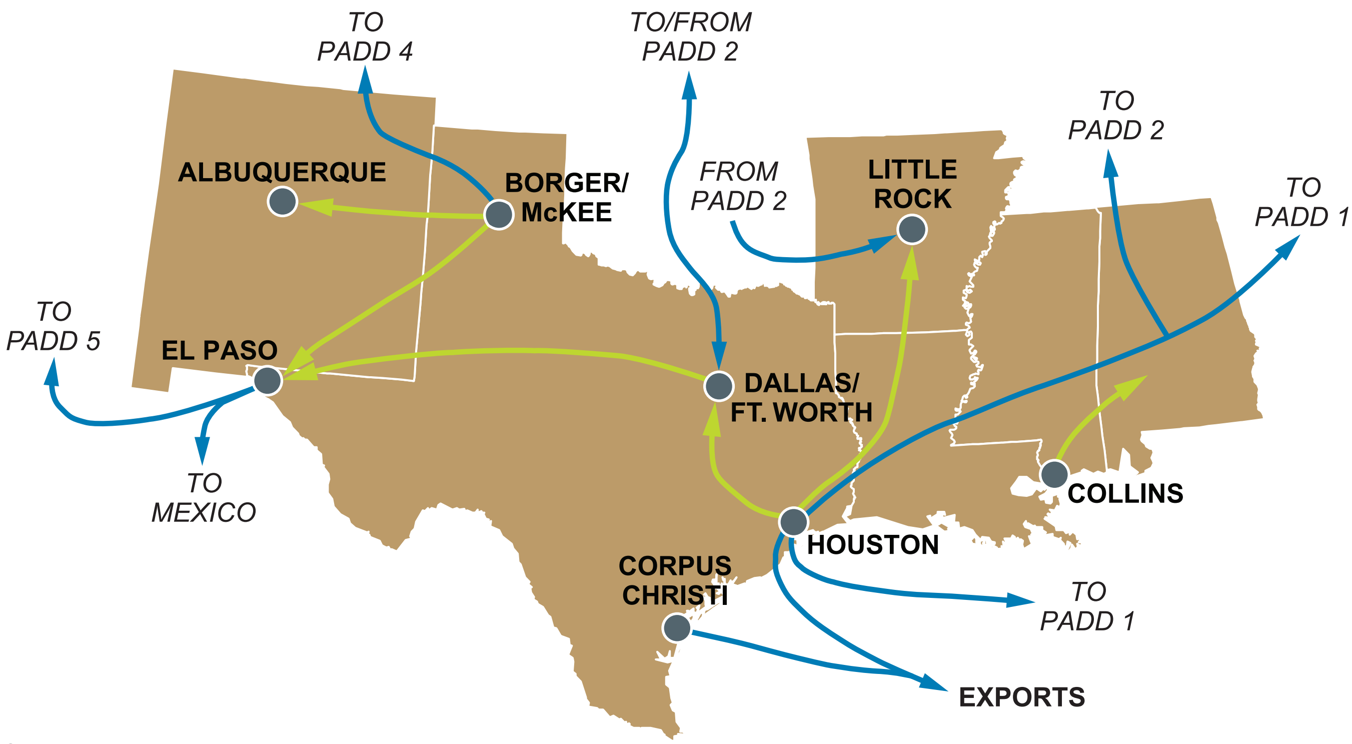


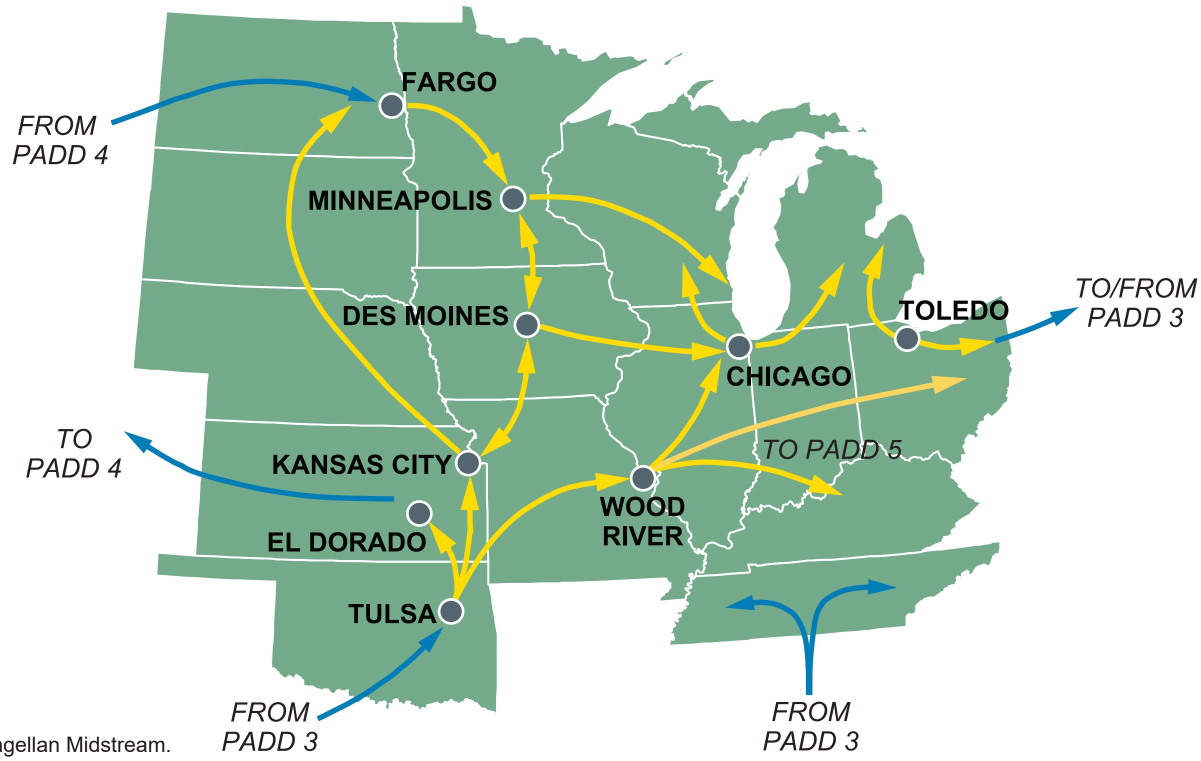
Figure 2-31. *PADD 3 (Gulf Coast) Pipeline/Marine Flows Diagram*

pipeline and the distance between terminals is what makes this possible. When the pipelines need to be reversed, the line fill needs to be displaced into a storage tank farm or moved past these facilities to a demand center farther down the pipeline.

Since these pipelines were built to solve regional supply/demand variances, they are also commonly utilized to transport gasoline, distillate, and jet fuel within the same pipeline. These products are batched in a manner to ensure the products maintain their chemical integrity and are transferred into tankage along the way to their destination. Where the products contact each other within the pipeline is called the interface. This product interface can be absorbed into one or both of the products depending on the batch size of the fuels and the amount of interface created, or it can be completely segregated into another tank for further refinement back into gasoline or distillate. These smaller diameter pipelines are generally located in PADD 2 and PADD 4, as illustrated in Figure 2-32 and Figure 2-33. The most notable pipelines in this region include Magellan Midstream Partners, Buckeye Partners, NuStar, Phillips 66 Pipeline, and Marathon Pipeline.

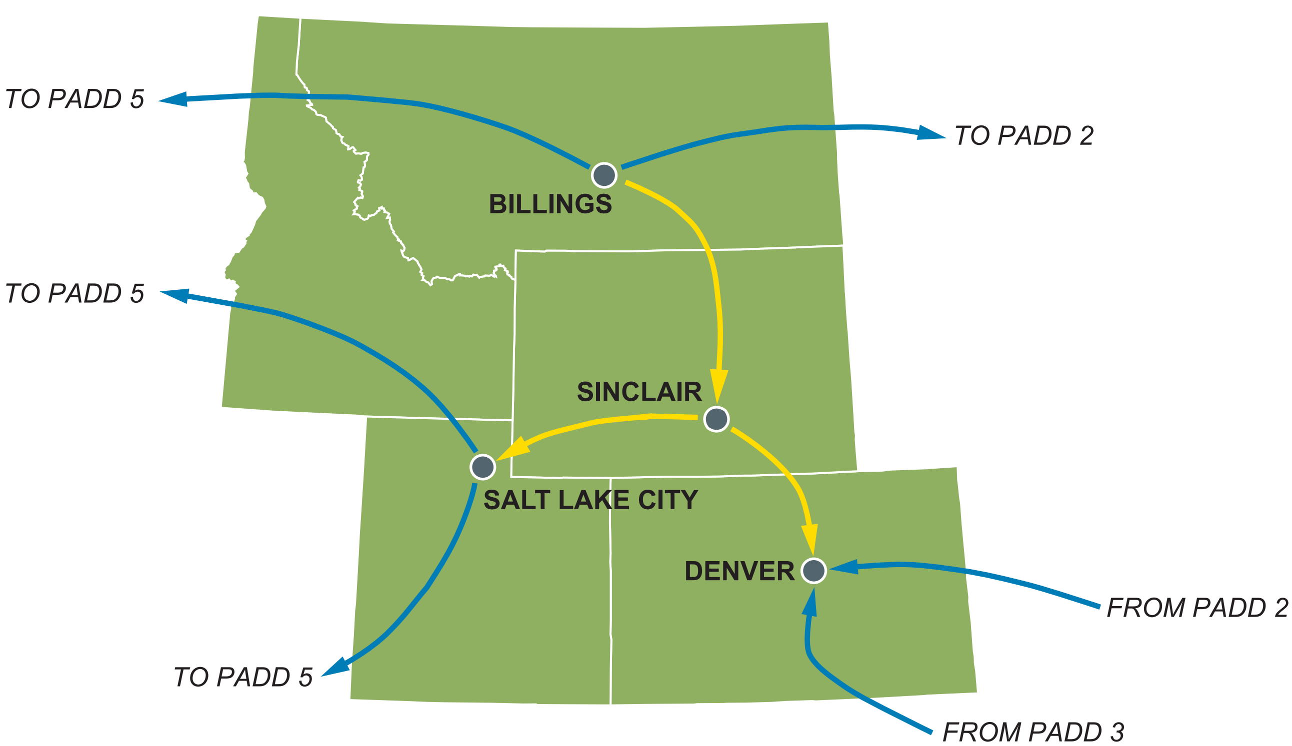
c. Storage and Delivery Terminals

All refined fuels pipelines throughout the United States deliver products to storage and delivery terminals for further distribution to the end user. Many of these terminals are located within close proximity of a demand center and consist of storage tanks, a truck rack, and/or a rail/marine loading facility. These terminals can be used to store product for the owner of the inventory or facilitate the delivery into another vessel (truck, railcar, barge/ship) for ultimate delivery to the customer. Storage and delivery terminals play an integral part in the distribution of transportation fuels. For jet fuel, many of the heavily trafficked airports within the United States have a pipeline connection to on-site storage tanks owned by a company operating on behalf of all of the airlines within the airport. In advance of these airports, the delivery terminal, owned by a third party, also has storage tanks set aside and designated as pre-airfield



Source: Magellan Midstream.

Figure 2-32. *PADD 2 (Midwest) Pipeline Flows*



Source: Magellan Midstream.

Figure 2-33. *PADD 4 (Rocky Mountain) Pipeline Flows* storage. The product in these tanks is tested and approved before being further distributed to the airport facilities or into a truck that will ultimately deliver into the airport.

4. Learning from the Past with a View of the Infrastructure Needs of the Future

The current focus for the owners of the inland refined fuels infrastructure is on the directional flow of the fuels to clear the supply centers and fuel the demand centers. Because there have been very few new greenfield refineries announced within the United States, there is little need for additional infrastructure. However, refineries throughout the country are continuing to find ways to debottleneck their current facilities and create incremental capacities. While the demand for refined fuels is starting to flatten compared to the historical norms, infrastructure plays a key role in supplying this product to the appropriate markets throughout the United States. Because the increased capacity from these refineries is not matched by local demand increases, refined fuels are being distributed to different demand centers than have been historically seen. To facilitate these movements, the refined products infrastructure is being modified to flow in the reverse direction and to distant markets.

As described in the National Petroleum Council's 2014 report, *Enhancing Emergency Preparedness for Natural Disasters*, there are many different regulatory fuel specifications in the United States that dictate the types of products that can be sold in a given area.[22] These numerous resulting regional formulations have also been described as boutique fuels. These specifications were established primarily to address environmental concerns. Variations include but are not limited to formulations that lower volatility of fuel to reduce emissions that contribute to ozone pollution. Further complicating matters, seasonal environmental vapor pressure restrictions require facilities to lower their inventories to minimum levels to replenish with gasoline that meet new requirements. This unavoidable annual regulatory supply constraint occurs around September of each year coinciding with peak hurricane season. These regional and seasonal complexities can impede the industry's ability to quickly respond to unplanned disruptions.

Figure 2-34 summarizes the various types of gasoline required in the United States by state and federal environmental laws.

The nation's oil and gas infrastructure is also being adapted to support the growing supply of renewable fuels (ethanol, biodiesel, and renewable diesel). Renewable diesel is a hydrocarbon product with a composition that is indistinguishable from petroleum diesel. Refineries are being modified to process renewable feedstocks to produce renewable diesel or a mixture of renewable diesel and petroleum diesel. The transportation fuel supply chain has been, and is being, modified to support increases in renewable fuel production and distribution. Existing labeling laws require identification of renewable diesel content at retail pumps. This requirement is a barrier to the transport and delivery of renewable diesel as a fungible product along with petroleum diesel, although it is compositionally the same. A change in the labeling law would allow expansion and optimization of renewable diesel into the marketplace. Such a change in labeling requires Congressional action to modify previous statutory language. Industry associations are supporting this change and are working to identify a legislative opportunity to enact it.

5. Exports — Refined Products

As the United States continues to see refinery capacity increasing through debottlenecking strategies and demand for petroleum-based fuels flattening to declining in many regional markets, there will need to be increased focus on the ability to export refined fuels through marine infrastructure (Figure 2-35).[23] PADD 2 refinery increases have changed the seasonal supply/demand scenario. Previously, a significant quantity of product was transferred into PADD 2 from PADD 3. Figure 2-36 shows the increased dependencies on exports for PADD 3 as the inter-PADD transfers

22 National Petroleum Council. 2014. "Appendix G: Hydrocarbon Liquids Supply Chain," in *Enhancing Emergency Preparedness for Natural Disasters*, p. G-13, https://www.npc.org/reports/2014-Emergency_Preparedness-lr.pdf.

23 Debottlenecking is a common industry term and can be described as capacity expansion of existing facilities through optimization.

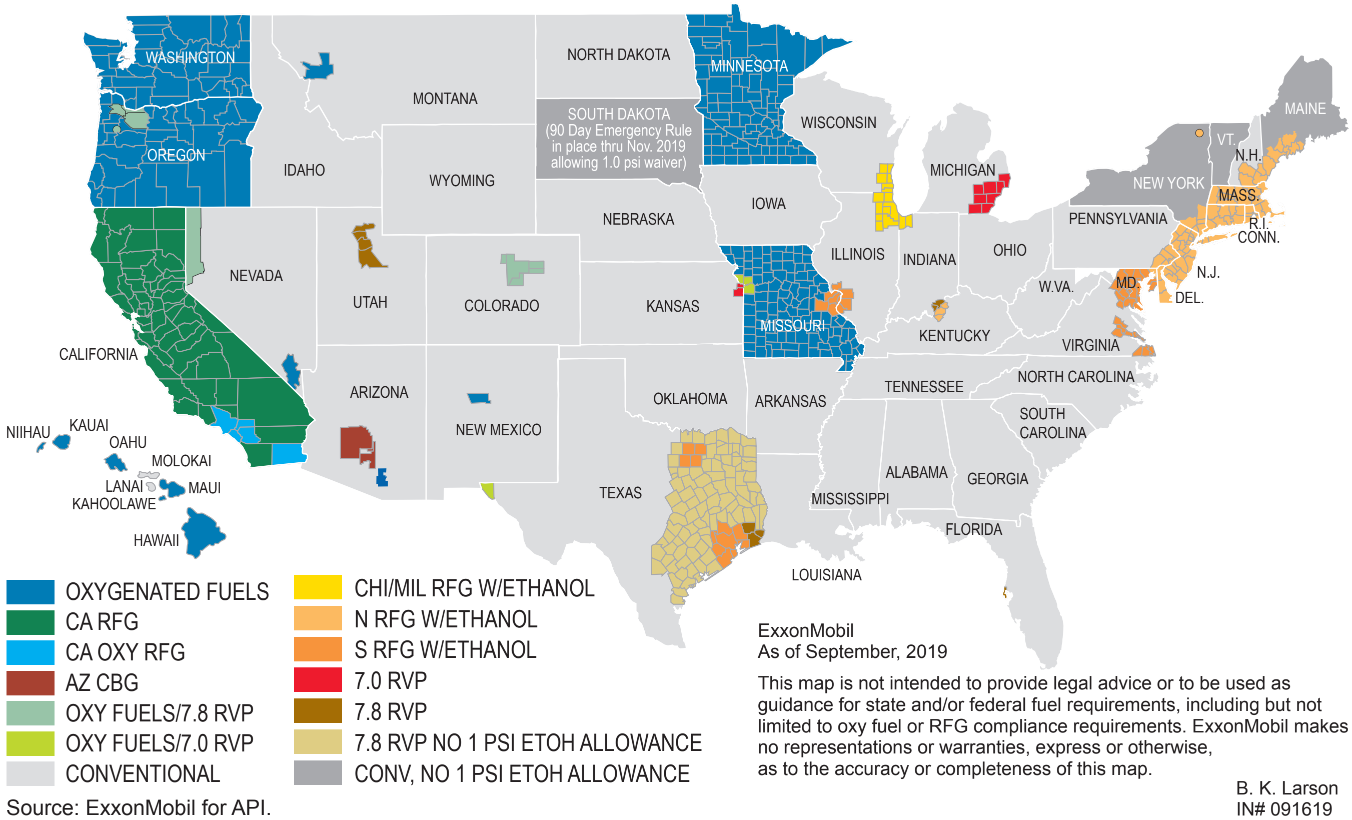


Figure 2-34. *U.S. Gasoline Requirements as of September 2019*

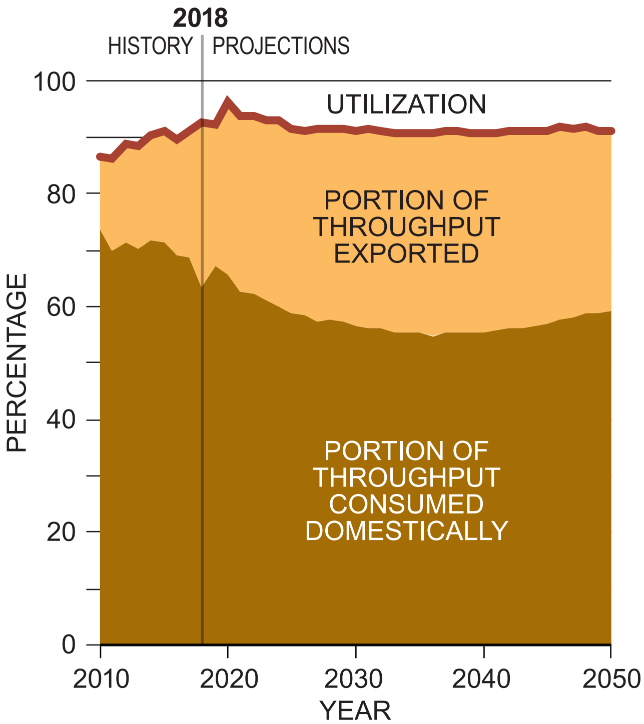
from PADD 3 to PADD 2 have steadily declined. The flow of the product has switched and now refineries in PADD 2 are supplying enough product to transfer some of it into PADD 1, PADD 3, and PADD 4. This capacity on the Gulf Coast that was previously moving north will need to the exported to continue to operate at equal capacities. Additionally, new capacity announced (~290M B/D by 2022) on the Gulf Coast will further add to the oversupply within PADD 3.

As the markets work to solve the supply/demand imbalances via exports, for all liquids including refined products there will need to be an emphasis on the marine export infrastructure. Figure 2-37 shows a live image of Gulf Coast marine traffic on May 19, 2019. As the Gulf Coast continues to see heavier traffic, there will need to be a continued focus on safety, clearance routes, and timing of vessels moving in and out of the ports. This focus will undoubtedly slow down vessels entering the facilities and fueling, thus causing a further delay. Improved infrastructure, including wider and deeper channels to improve safety and efficiency of existing traffic and allow larger and more deeply loaded vessels to safely transit into and out of ports without impacting existing traffic, is needed to meet existing and forecasted export demand. This situation is especially acute in the Houston Ship Channel. To expedite the delivery of these improvements, Congress and the administration should consider innovative project authorization, funding, and construction strategies.

6. Resiliency — Refined Fuels Transportation System

a. Strengths

- Products Supply Security: Some pipelines originating in the Gulf Coast are connected to several refineries. For example, the Colonial pipeline has connections to 29 refineries and 267 distribution terminals. In the event of an outage at any one refinery, pipelines can easily access alternative supplies from the region.
- Pipeline Excess Capacity: Over the past 10 years, PADD 2 refining capacity has increased. As a



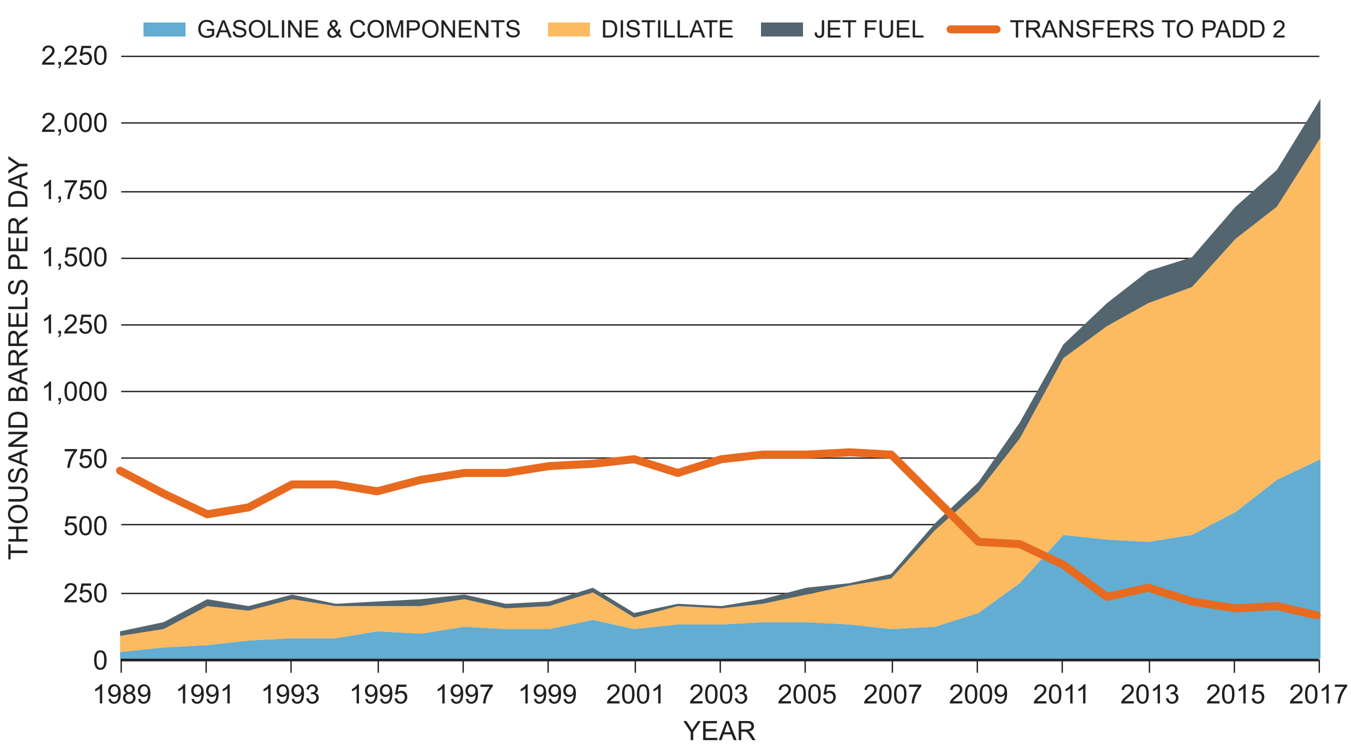
Source: EIA, *Annual Energy Outlook 2019*.

Figure 2-35. *U.S. Refinery Utilization Relative to Products Exported*

result there has been a decline in PADD 3 to PADD 2 transportation fuel movements. The excess pipeline capacity between the two regions provides swing supply into the region during in-region refinery outages.

b. Exposures

- Products Supply Security: Flint Hills, Colonial, and Explorer pipelines are all sourced from refineries in the Texas Gulf Coast. During Hurricane Harvey in August 2017, Colonial and Explorer pipelines shut down due to a lack of product supply as a result of refinery closures. Explorer supplies jet fuel to Dallas-Fort Worth International Airport.
- Weather: Underground pipes are not affected by weather and can remain operable, but pumping facilities can be adversely affected and can have cascading effects.
  - Following Hurricane Katrina in 2005, power outages to key pumping facilities in Mississippi, along Colonial and Plantation pipelines,



Source: EIA, Petroleum & Other Liquids.

Figure 2-36. *PADD 3 Exports and Inter-PADD Transfers by Product*

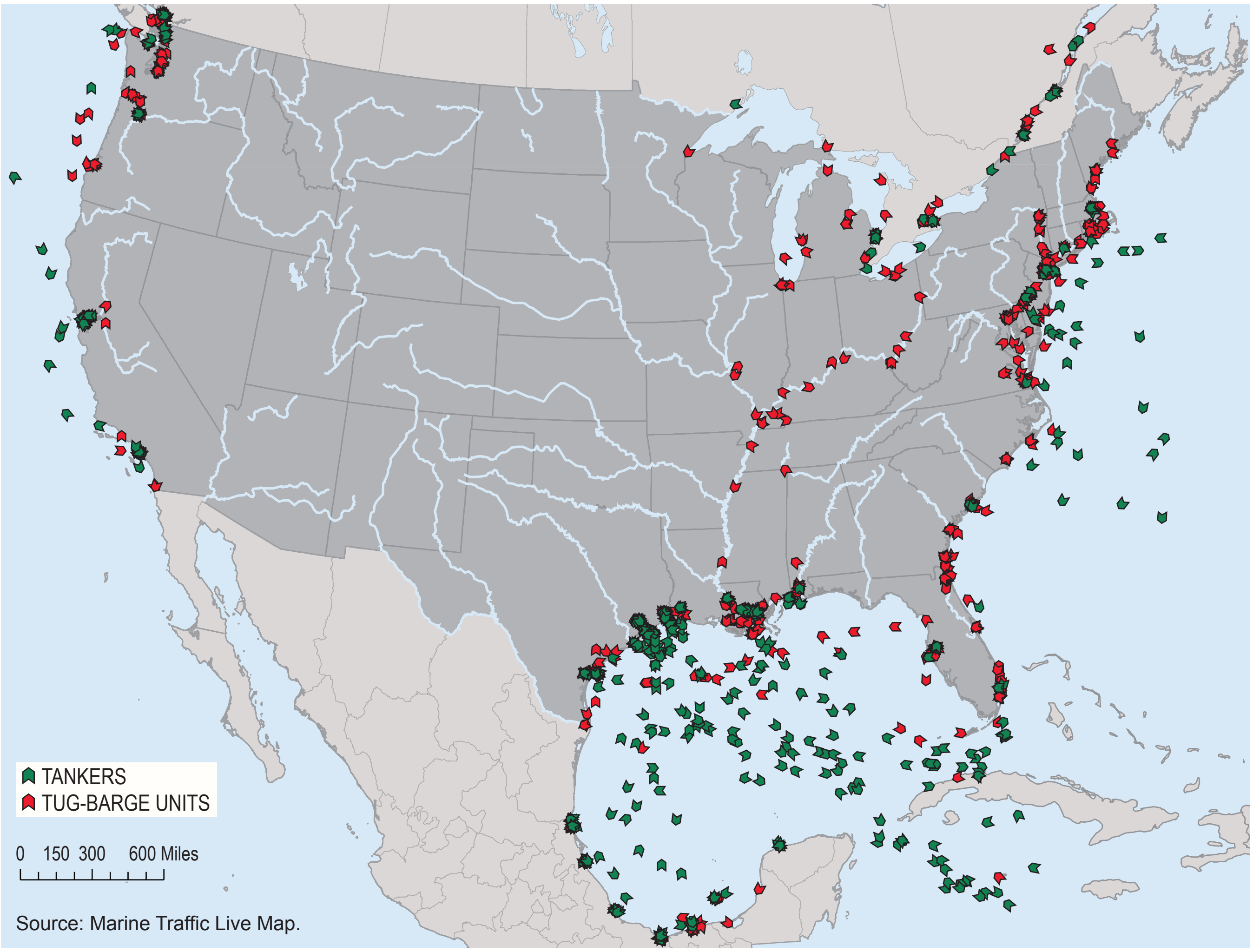


Figure 2-37. *Marine Traffic May 19, 2019*

rendered both pipelines inoperable, cutting off transportation fuels supply to dependent markets.

- After Hurricane Sandy, power was out to Buckeye's Long Island Pipeline System for several days. At the time of the outage, Buckeye was scheduled to receive a large delivery of jet fuel from Colonial Pipeline for delivery to New York City area airports. The Buckeye outage prevented Colonial from clearing the jet fuel from its system, backing up shipments on its 885 MB/D Line 3 as far south as the line's origin in Greensboro, North Carolina.

- The dependence of the East Coast on the Colonial and Plantation pipelines to meet consumption is a major vulnerability. Almost 50% of PADD 1 demand for refined products is supplied via these pipelines. There are no refineries between Alabama and Philadelphia. Given this region's lack of refinery capacity, nearly all supply of transportation fuels comes from other regions and therefore has limited supply options. Supply from these pipelines is difficult to replace in many markets in the Southeast that lack waterborne access. Conversely, an outage on these pipelines could back up refinery output in the Gulf Coast with no available outlet.

c. Case Study: Colonial Pipeline Shutdown of 2016

An incident that occurred in mid-2016 due to a leak on Colonial Pipeline caused a 12-day interruption of supply into PADD 1, but shows the resilience of the distribution system to supply products to market. There are 15 storage tank locations along the route, more than 50 delivery points and seven airports that receive jet and other fuel directly from pipeline spurs.[24] Total motor gasoline stocks in the lower Atlantic (PADD 1C) fell by nearly 6 million barrels—the largest reduction in weekly region gasoline inventories on record. However, regional storage was able to handle the outage and the shortfall in deliveries was made up by increasing volumes moved long distance via truck, and still more barrels supplied by ship and barge. The Washington/Baltimore airports came within hours of a stock out. Had the outages extended for longer periods of time, it would have been increasingly more difficult for the energy distibution network to balance out regional supply and demand.

Finding: U.S. refiners are pushing the limits of capacity utilization. With minimal slack in the system, loss of capacity can be significant and create cascading constraints on upstream production. Two mitigations to capacity risk are storage and exports.

D. Natural Gas Infrastructure History and Current State

1. General Overview of Transportation System

In the United States, natural gas is delivered to end users via an extended and interconnected network of pipelines comprising 1,308,612 miles of distribution mains, 301,503 miles of transmission pipelines, and 18,357 miles of gathering lines.[25] Pipelines are the primary mode of transportation for delivering natural gas to the domestic market. There are instances where the end user receives the molecules by truck in the form of compressed natural gas (CNG) or liquefied natural gas (LNG). However, the percentage market share of these two delivery options is negligible.

The natural gas infrastructure system in the United States has taken over a half-century to build. This system is complex in both structure and operation and involves a far-reaching transnational and cross-border pipeline system. It comprises a network of gathering, transmission, and local distribution pipelines, natural gas processing, storage facilities, and LNG terminals. The gas infrastructure system operates according to a variety of regulatory regimes, which is discussed in Chapter Three, "Permitting, Siting, and Community Engagement for Infrastructure Development."

2. History and Current State

a. Natural Gas Pipelines

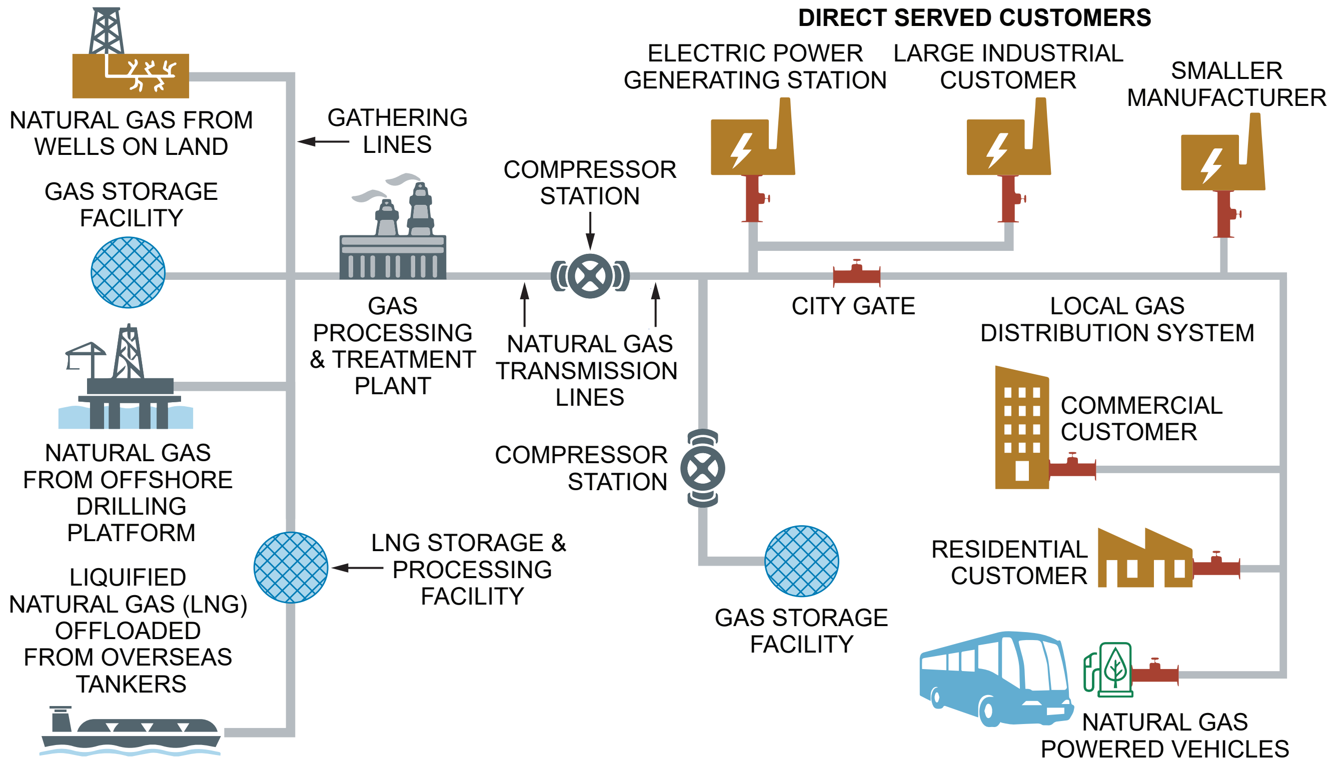
Throughout much of the 19th century, natural gas was used almost exclusively as a source of street lighting. Infrastructure did not exist to transport gas over long distances. It was not until the late 1920s that the industry began to develop a transportation system to connect production areas to markets.

There are four main types of pipelines within the U.S. transportation grid: gathering systems, interstate pipelines, intrastate pipelines, and distribution systems. Historically, gathering systems were usually low pressure, small-diameter pipelines that move natural gas from the wellhead to a centralized location. Current gathering pipeline systems are larger in diameter and operated at higher pressure. Gathering systems' pipelines flow into interstate or intrastate pipelines. These can range in size from 2" to 42" in diameter and are typically constructed from steel pipe. Interstate pipelines carry natural gas across state borders, while intrastate pipelines carry natural gas within a state. The interstate and intrastate pipelines generally supply natural gas to local distribution systems (Figure 2-38). Some large industrial, commercial, and electric generation customers receive natural gas directly from interstate and intrastate pipelines; however, most customers receive gas from a local distribution company (LDC) that has the regulatory responsibility to sell gas on demand at the delivery point.

Since 1984, onshore transmission pipeline mileage has gradually grown from approximately

24 Braziel R., "The Problem With Pipelines; Colonial Pipeline and America's Fuel Transportation Networks," *Forbes*, November 2016, https://www.forbes.com/sites/energysource/2016/11/08/the-problem-with-pipelines-colonial-pipeline-and-americas-fuel-transportation-networks/#31674ebc3d90.

25 Bureau of Transportation Statistics, "U.S. Oil and Gas Pipeline Mileage," https://www.bts.gov/content/us-oil-and-gas-pipeline-mileage (accessed July 1, 2019).



Source: Pipeline and Hazardous Materials Safety Administration.

Figure 2-38. *Natural Gas Value Chain*

280,000 miles to the current distance of 301,503 miles (Figure 2-39).[26] Interstate pipelines total approximately 210,000 miles with an additional 90,000 miles of intrastate pipelines and gathering systems.

As described in Chapter One, "Supply and Demand," since the application of horizontal drilling combined with hydraulic fracturing technology for economic production of shale gas, domestic natural gas supply has grown and will continue to grow over the coming decades. This supply growth is characterized by a geographic shift, with the once-dormant and now predominant gas-producing basin, Appalachia, serving as a prime example. Meanwhile, a number of pipeline projects are underway to transport natural gas growth to the Gulf Coast to supply growing LNG exports. Since the onset of the shale development, investment in natural gas infrastructure has occurred through the expansion or repurposing of existing pipelines as well as in new pipelines. These investments have enabled the rapid growth in domestic gas supply. But, given the projected supply growth, the U.S. pipeline system, particularly the interstate grid, must continue to expand to accommodate this growth. Investment in new natural gas infrastructure projects will be dictated by market forces to address supply/demand imbalances and will be specific to different regions.

26 U.S. Energy Information Administration, "Estimated Natural Gas Pipeline Mileage in the Lower 48 States, Close of 2008," https://www.eia.gov/naturalgas/archive/analysis_publications/ngpipeline/mileage.html (accessed July 1, 2019).

b. Natural Gas Storage

The ability to store and retrieve large quantities of natural gas has been a key factor in the growth and development of the natural gas industry. Most commonly, natural gas is stored under pressure in underground facilities. The underground facilities are depleted gas reservoirs/fields, aquifers, or salt domes. The characteristics of underground storage reservoirs are their capacity to store natural gas, the rate at which withdrawal of natural gas can be made, and their relative proximity to the market. Underground storage is a primary tool in maintaining the integrity of the pipeline system.

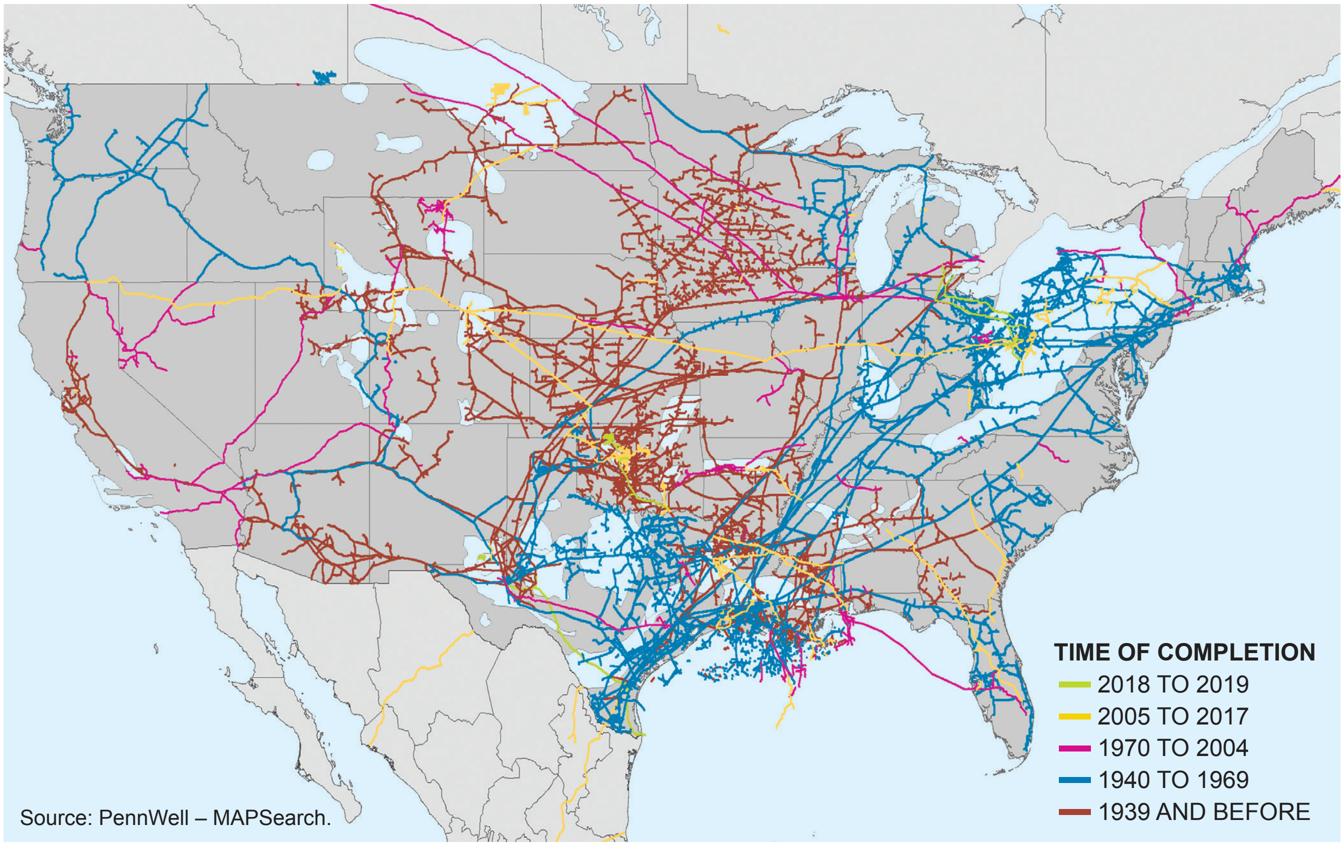


Figure 2-39. *North America Natural Gas Pipeline System Evolution Since 1939*

There are three fundamental reasons for using underground storage:

- Reduce the need for both swing natural gas production deliverability and pipeline capacity by allowing production and pipeline throughput to remain relatively constant
- Reduce pipeline demand charges (pipeline capacity commitments) by customers
- Hedge against natural gas price increase, or to arbitrage gas price differentials.

Pipelines, LDCs, and generators also use storage for operational flexibility and reliability, providing an outlet for unconsumed natural gas supplies or a source of gas to meet unexpected gas demand. Storage at trading hubs can provide balancing, parking, and loan services further enhancing the flexibility of the market. Natural gas is typically injected during the summer season (April to October) and withdrawn in the winter season (November to March). In the long run, storage helps maintain operational stability, meeting peak demand and narrowing seasonal price differentials.

3. Storage Current State

There are 414 underground natural gas storage facilities in the United States, of which 388 are active (Figure 2-40).[27] The EIA measures underground natural gas storage capacity in two ways: design capacity (the sum of reported working natural gas capacities of active storage fields) and demonstrated peak capacity (sum of peak monthly working natural gas volumes observed). The total storage capacity in 2017 was 9,261 BCF, with a working gas capacity of 4,851 BCF.[28] The storage fields vary by type with depleted producing fields

27 U.S. Energy Information Administration, Natural Gas, "Underground Natural Gas Storage Capacity," https://www.eia.gov/dnav/ng/ng_stor_cap_a_EPG0_SAD_Count_a.htm (accessed July 1, 2019).

28 Ibid.

making up 81% of underground storage capacity.[29] Aquifer storage makes up 9%, and salt domes make up the remaining 10%.[30] The majority of underground natural gas storage facilities are located in the South Central region, primarily comprised of depleted fields and salt domes (Figure 2-41 and Figure 2-42).

In 2018, the data collected and reported by the EIA showed decreases in both design capacity, falling by 0.3% or 13 BCF, and demonstrated peak storage capacity, falling by 1.2%, or 54 BCF (see Figure 2-43 and Figure 2-44).[31] These declines were the largest year-on-year declines since 2012. Declines in design capacity resulted from closures of unused facilities and reductions in capacity at individual facilities, while declines in demonstrated peak capacity resulted from lower natural gas injections into storage facilities. The slowed growth in underground natural gas storage capacity in the U.S. Lower 48 states in recent years is in clear contrast to 2012 and 2013, which saw big increases in salt dome storage in the South Central region. Salt dome storage generally offers higher deliverability rates than other types of storage and is therefore responsive to sudden changes in price related to extreme weather. However, EIA's 2018 data show lower utilization of salt facilities in the South Central region, which resulted in a lower demonstrated peak capacity in the region.

Storage capacity growth slowed over the past 5 years due to abundant supply and low seasonal price spreads. However, the Appalachian region increased development of storage capacity. Storage continues to be utilized to manage nonuniform loads of local distribution companies, supply natural gas-fired power generation, and provide on-demand supply for power generation to support growth in renewable power. However, underground natural gas storage is geologically limited.

29 Ibid.

30 Ibid.

31 U.S. Energy Information Administration, "Natural Gas Storage Dashboard," https://www.eia.gov/naturalgas/storage/dashboard/commentary/20190408 (accessed July 1, 2019).

a. Aboveground Storage

In 2018, there were 157 LNG storage facilities in service with a combined capacity of 56 million

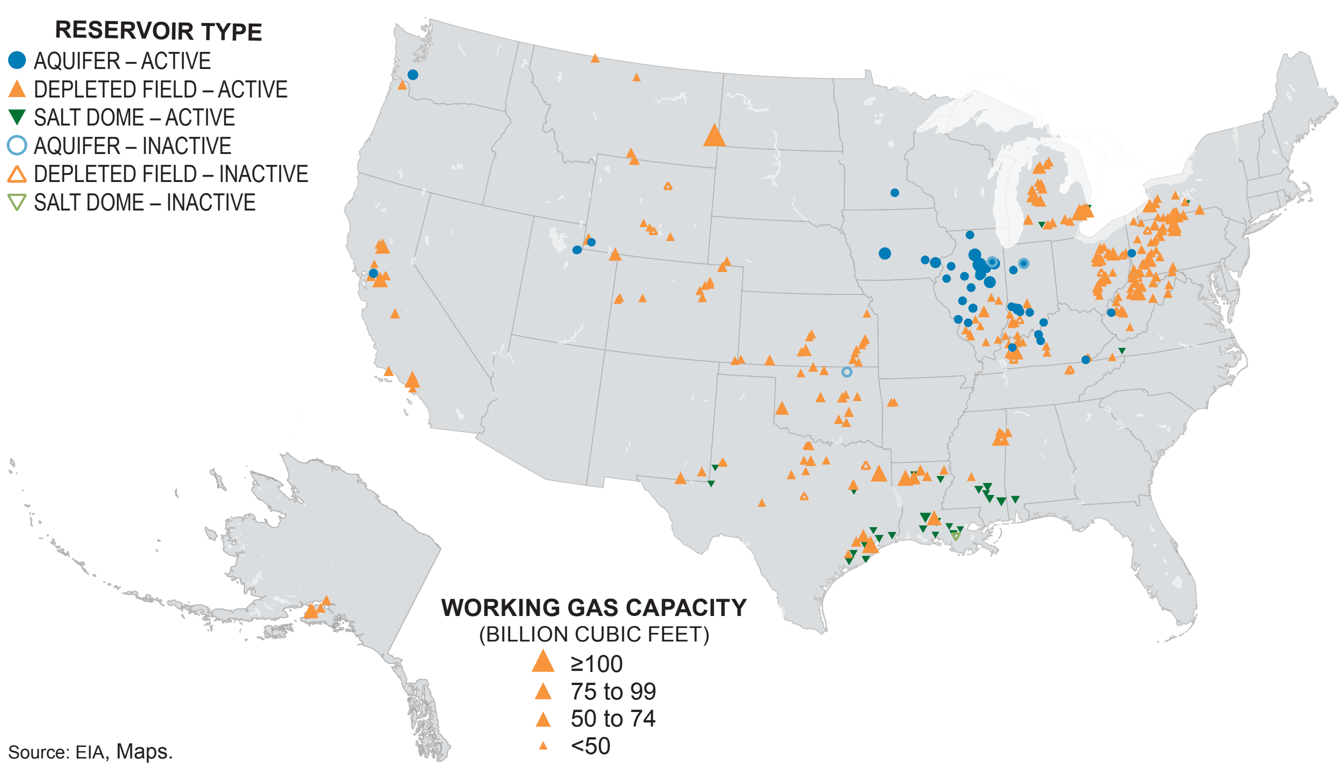


Figure 2-40. *U.S. Underground Natural Gas Storage Facility by Type, December 2017*

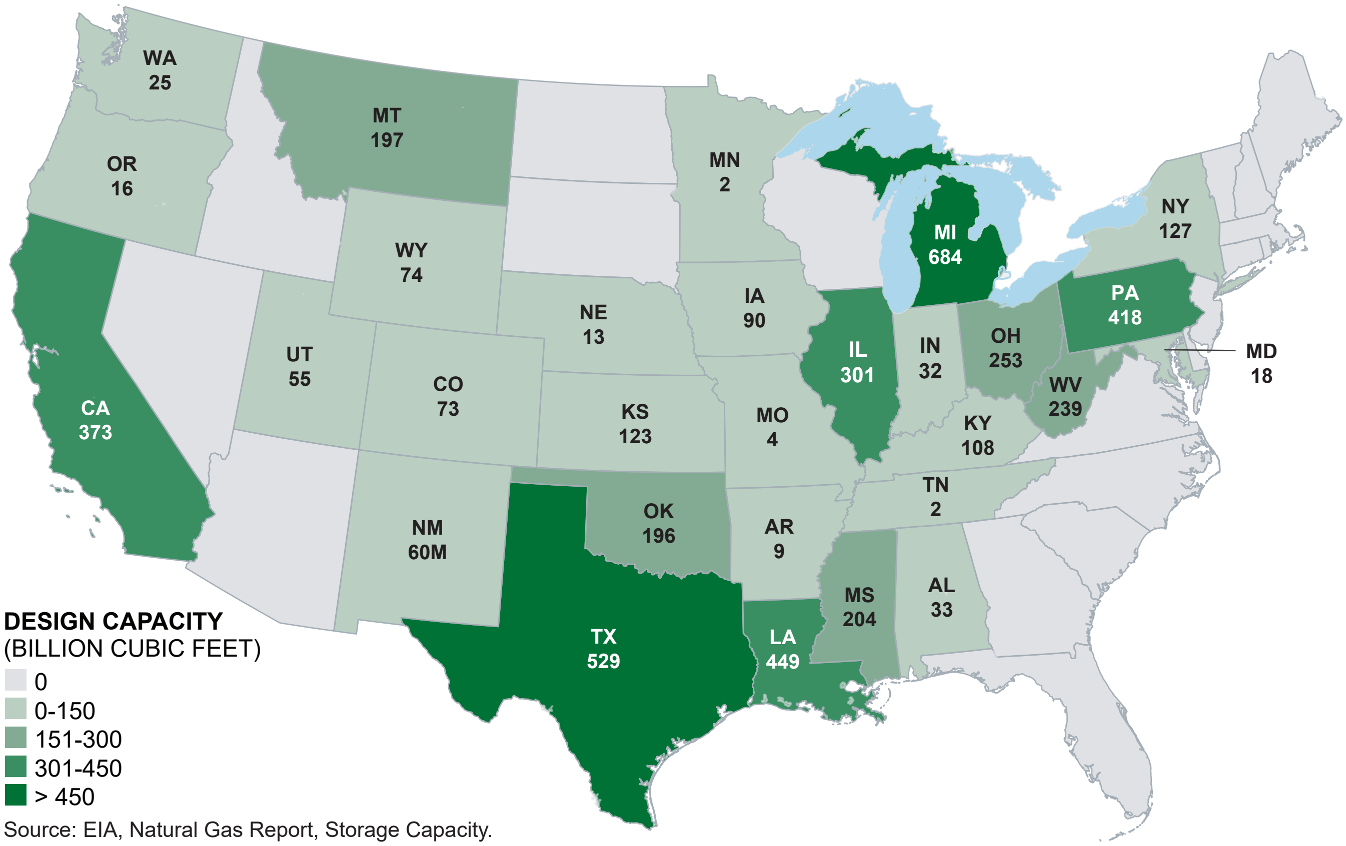
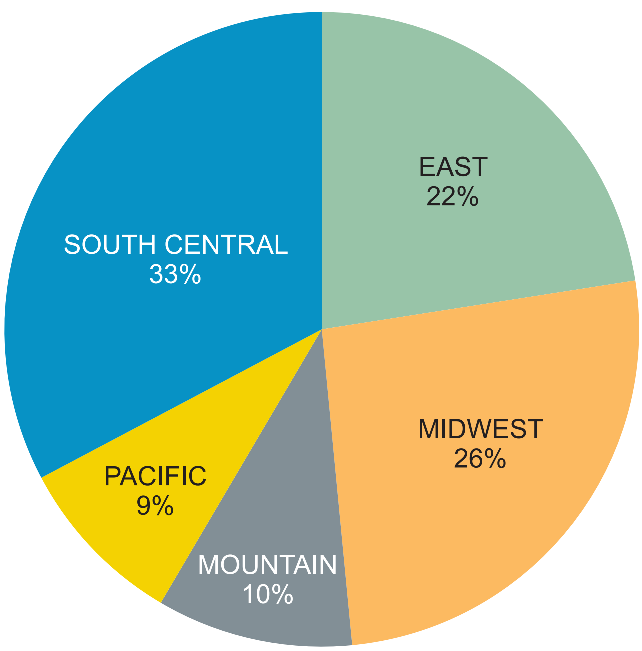


***Figure 2-41.** U.S. Underground Natural Gas Storage Design Capacity, November 2018*



Source: EIA, Natural Gas, Storage Capacity.

***Figure 2-42.** U.S. Underground Natural Gas Storage Design Capacity by Region*

barrels.[32] Aboveground LNG storage capacity is projected to grow where new LNG export terminals are constructed.

LNG storage facilities are used by LNG import terminals to smooth gas deliverability between cargoes or by local utilities for peak-shaving.[33] LNG storage facilities at import terminals continually cycle through supplies as new shipments arrive. At LNG export terminals, LNG storage

32 Pipeline and Hazardous Materials Safety, "LNG Facilities and Total Storage Capacities," https://www.phmsa.dot.gov/data-and-statistics/pipeline/liquefied-natural-gas-lng-facilities-and-total-storage-capacities (accessed October 5, 2019).

33 Cove Point LNG Terminal has a storage capacity of 14.6 BCF and a daily send-out capacity of 1.8 BCF. The terminal connects, via its own pipeline, to the major Mid-Atlantic gas transmission systems of Transcontinental Gas Pipeline, Columbia Gas Transmission, and Dominion Energy Transmission.

Dominion Energy, "Cove Point Terminal," https://www.dominionenergy.com/company/moving-energy/dominion-energy-transmission-inc/facilities-projects-and-programs/cove-point/cove-point-terminal (accessed July 1, 2019).

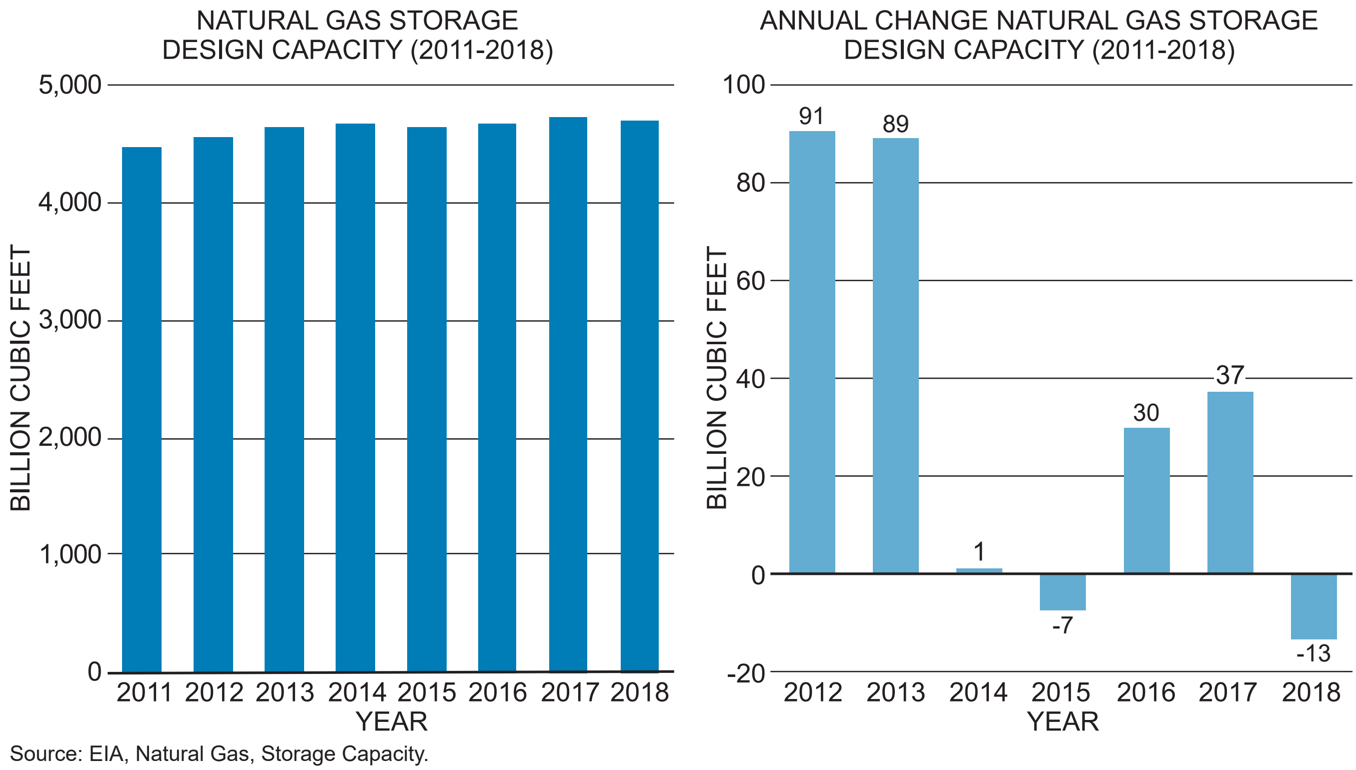


Figure 2-43. *Natural Gas Storage Design Capacity*

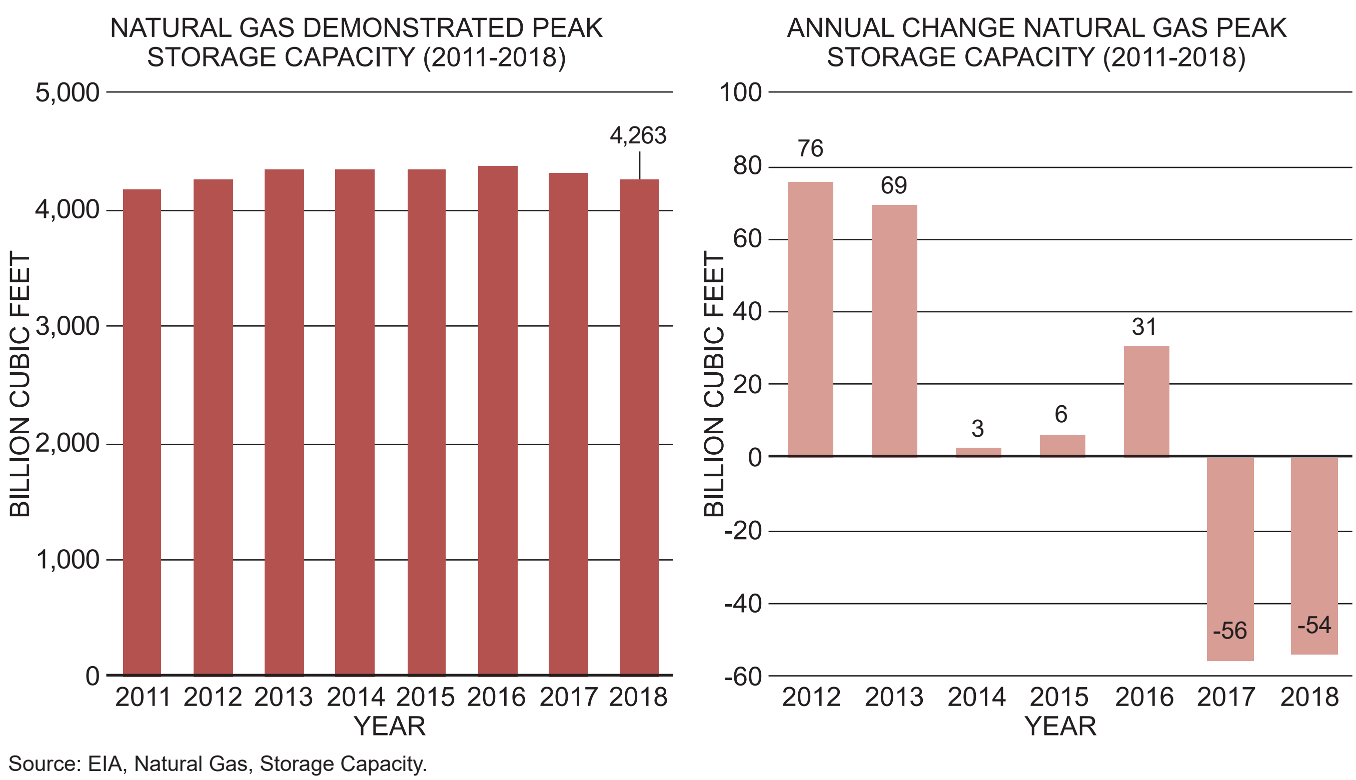


Figure 2-44. *Natural Gas Demonstrated Peak Storage Capacity*

facilities are used after gas has been liquefied and stored until it is loaded onto LNG carriers.[34]

LNG storage facilities at local utilities are used for a different purpose: these facilities may hold up to 4 BCF of gas, which is stored for the coldest days of the year. Larger LNG storage facilities that are not associated with import terminals liquefy the gas they receive directly from the pipeline grid. Smaller storage sites do not have liquefaction capabilities and receive LNG by truck. LNG storage facilities have advantages over underground storage in that they are not geographically restricted to the naturally occurring geologic structures described above. The deliverability rates of LNG storage can be designed for much higher rates than typical underground storage. However, LNG storage facilities are generally more costly than underground storage on a per unit basis, so these facilities are operated as peak-shaving only to mitigate seasonal demand spikes. LNG storage facilities are also used by pipeline companies for load-balancing and to manage peak day demand.

b. Liquefied Natural Gas Terminals

LNG is natural gas that has been liquefied for storage and transport. The liquefaction process begins when natural gas is transported via pipeline to a liquefaction facility. There, components that will freeze at low temperatures (water, carbon dioxide, and heavier hydrocarbons) are removed and the remaining gas is chilled to about -260°F, at which point the gas becomes a liquid.[35] The volume of natural gas in its liquid state is about 600 times smaller than its volume in its gaseous state, making it easier and more efficient to store and ship and allowing producers to deliver clean-burning natural gas from remote production areas to distant markets where additional supplies are needed.

Efforts to liquefy natural gas for storage began in the early 1900s, but it was not until 1959 that the world's first LNG ship carried cargoes from Louisiana to the United Kingdom, proving the feasibility of transoceanic LNG transport. The widespread use of liquefaction allows natural gas to be transported via marine vessels as LNG from producing countries to global markets. This logistical flexibility helps improve the security of gas supplies worldwide and is making LNG one of the fastest-growing energy markets.

LNG terminals have historically played a limited role in the natural gas infrastructure system. The first liquefaction terminal in the United States was built in Kenai, Alaska. ConocoPhillips began operations of the Kenai LNG plant in 1969. Up until recently, it had been the only LNG export plant of domestic production in the United States. In the early 2000s, LNG import terminals were approved in anticipation of a need for natural gas imports. These terminals were located in Everett, Massachusetts; Cove Point, Maryland; Elba Island, Georgia; Lake Charles, Louisiana; and the Gulf of Mexico offshore (Gulf Gateway). At the time, these five terminals had a combined peak capacity of more than 1.3 trillion cubic feet per year.[36] As domestic natural gas became abundant and displaced the need for LNG imports, these same facilities provided a strong starting base for the development of export facilities.

As American exports of LNG have increased, LNG export terminals have become an important demand component of the domestic infrastructure system. As of September 1, 2019, five LNG export terminals are operational and capable of exporting LNG: Cheniere Energy's Sabine Pass LNG in Louisiana and Corpus Christi LNG in Texas, Dominion Energy's Cove Point LNG in Maryland, Sempra Energy's Cameron LNG in Louisiana, and Elba Island LNG.[37] Fifteen additional LNG export projects have been approved by the Federal Energy Regulatory Commission (FERC), eight of which are under construction, while ten additional export projects have been

34 The Sabine Pass LNG Terminal in Louisiana has five LNG storage tanks capable of holding 17 BCF. Cheniere, "Top 5 Global Supplier of LNG by 2020," https://www.cheniere.com/terminals/sabine-pass/ (accessed July 1, 2019).

35 Center for Liquefied Natural Gas, "LNG Process," https://lngfacts.org/about-lng/lng-process/ (accessed September 1, 2019).

36 U.S. Department of Energy, "Liquefied Natural Gas: Understanding the Basic Facts," https://www.energy.gov/sites/prod/files/2013/04/f0/LNG_primerupd.pdf (accessed July 1, 2019). The Northeast Gateway located offshore Massachusetts began operations in 2008, slightly later than this first suite of LNG import terminals.

37 Federal Energy Regulatory Commission, "Existing North American LNG Export Facilities," https://www.ferc.gov/industries/gas/indus-act/lng/lng-existing-export.pdf (accessed August 26, 2019).

proposed to FERC and five export projects are in the pre-filing stage (Figure 2-45).[38] These LNG export projects will drive significant change to existing natural gas infrastructure across the country and require new investments to grow this infrastructure.

c. Trucks and Rail

Trucks and rail can be used to deliver natural gas either as LNG or CNG. These are typically stop-gap forms of transportation due to liquefaction and compression costs, as well as insufficient infrastructure. For example, trucking of LNG and CNG exists in distribution areas that lack sufficient pipeline infrastructure to meet a peak day load or need supply to support a maintenance or construction outage. Trucked LNG is also used to fuel remote power generation and support upstream drilling operations.

38 Ibid.

4. The Impact of Shale on Natural Gas—Change in Major Flow Patterns

With North American gas supply growing, new infrastructure is required to bring new supply to replace declining production from historical basins and to supply growing demand centers, such as LNG export terminals on the Gulf Coast and gas for power demand throughout the country. Additional pipeline capacity, storage capacity, and LNG export terminals will be required to underpin this growth. As a result, many traditional pipeline corridors are reversing the flow direction in which natural gas travels while other corridors are rapidly expanding in terms of capacity.

a. Natural Gas Flows Pre- and Post-Shale

Prior to the shale development, most natural gas flowed from the Gulf Coast and the midcontinent to the Midwest, West Texas, New Mexico, and the Northeast, supported with some LNG imports into New England. Rockies natural gas flowed both

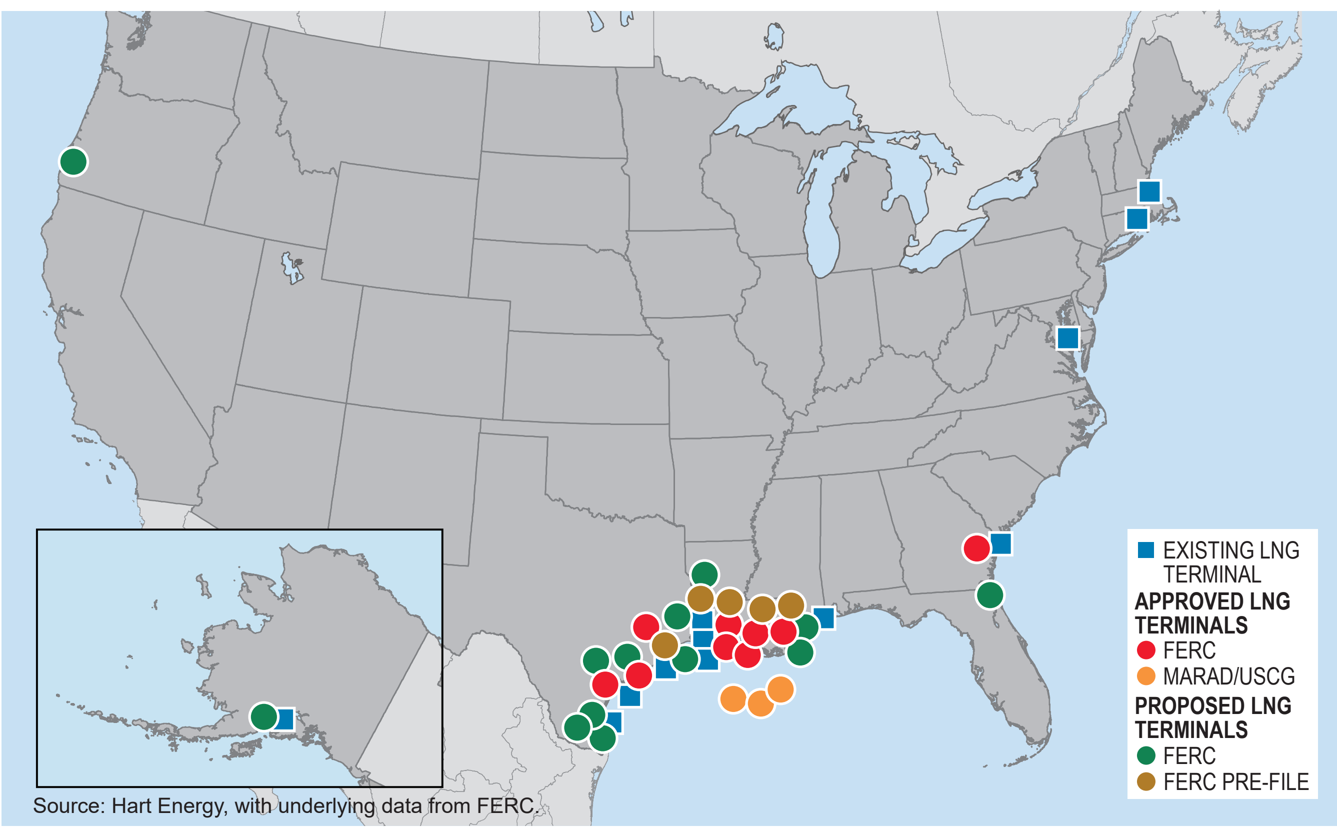


Figure 2-45. LNG Terminals, Existing, Approved, and Proposed

east and west, but primarily to California. These flow patterns are represented by the green arrows in Figure 2-46.

The abundance of shale natural gas has changed flow patterns as represented by the red arrows in Figure 2-46. Flows from Texas and Louisiana to the Northeast have reversed, feeding consuming markets in the Gulf Coast region and the multiple LNG export facilities along the coast. In addition to flowing south, Appalachia natural gas began to flow into the Midwest, where it created a major oversupply. Bakken gas also began to flow to the Midwest, into that same oversupply. Rockies gas continued to flow both west and east, but the eastbound flows could not go past Illinois because of market pressure from Northeast supplies. Finally, West Texas (Permian Basin) gas continues to supply the Southwest and California but will soon be a primary supply source into South Texas exports to Mexico and a major supply into Gulf Coast LNG exports.

b. Natural Gas Regional Flow Dynamics

As natural gas pipeline infrastructure evolved to address the rapidly growing levels and locations of natural gas supply, it followed three main vectors. First, pent-up Rockies gas, primarily from tight sands and coalbed methane, began to flow east with the construction of Rockies Express. Second, major shale gas development in East Texas and Northwest Louisiana led to multiple major pipelines to move that gas east

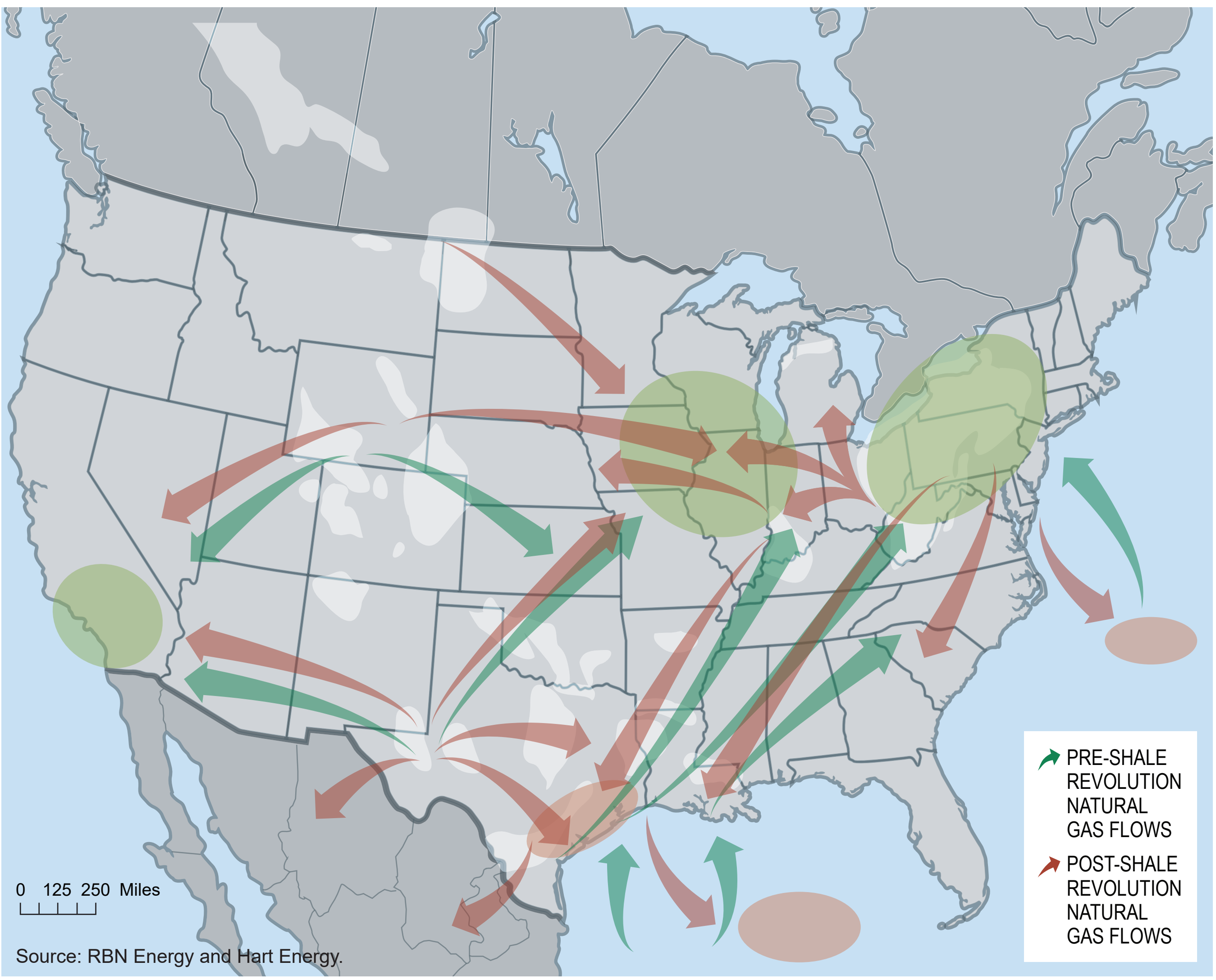


***Figure 2-46.** Gas Flows Pre- and Post-Shale*

into traditional paths of flow to demand markets in the Northeast and Midwest. Third, as Northeast supplies in Appalachia became the fastest-growing supply source, infrastructure changes were made to modify and use existing pipelines to move natural gas out of the region along five major corridors:

1. South to the Gulf Coast down the Ohio Valley
2. South to rapidly growing Southeast U.S. markets along the Atlantic Coast
3. West into the midcontinent to feed the extensive pipeline network serving Chicago and interconnecting to routes south
4. East, into the large gas-consuming regions of the Northeast
5. North, into Eastern Canadian markets traditionally served by Western Canadian gas.

The next generation of major pipeline construction over the coming months will involve the development of greenfield pipeline projects east out of the Permian Basin, the most prolific source of new supply.

Findings:

- Infrastructure projects in the early phases of the shale development were generally accomplished using existing pipeline paths, and thus were able to be relatively economic and to avoid many of the environmental and land impacts of new pipeline construction.
- New supply sources of natural gas have fewer transportation options, and production levels may be impacted without significant natural gas pipeline investment.
- The current and next generations of major projects have generally moved beyond what can be done with existing infrastructure, and thus involve expensive and more impactful greenfield pipelines. This regional evolution heightens the importance of finding sufficient shipper commitments to support the economics of the new construction, and of overcoming approval and permitting obstacles, including stakeholder concerns.

c. Infrastructure Buildout 2000 to 2008: The Rockies

In the mid-2000s, immediately prior to the shale development, a major focus of the natural gas market was in the Rockies, the only region of the United States experiencing production growth during a period when most basins were in decline. Rockies natural gas supply was surging, coming on so fast that it overwhelmed the pipeline takeaway capacity out of the region. Natural gas prices in the Rockies region were driven down to pennies due to the lack of pipeline capacity while a growing supply/demand imbalance in the rest of the country drove prices to very high levels—between $8/MMBTU and $13/MMBTU.

The response to these issues was the Rockies Express (REX), a new, 1.9 BCF/D pipeline from the Rocky Mountains to eastern Ohio (Figure 2-47). At the time, REX was the largest natural gas pipeline built in the United States in the previous 20 years and would ultimately span 1,663 miles, becoming one of the nation's longest interstate pipelines. The pipe was intended to move natural gas from a region experiencing gas gluts to regions badly in need of new supplies. REX came online in phases, reaching Missouri in 2008 with completion into Ohio in 2009. As Rockies gas flowed into the Northeast market, price discounts for Rockies gas disappeared, and new Rockies supplies contributed to lower prices across the United States.

However, by the time REX was operating, a far more dramatic period of production growth was underway. Ultimately, the epicenter of shale development was significant production in Marcellus, at the *outlet* of REX. The huge investment in REX had resulted in a pipeline that carried gas *to* the most rapidly growing supply area, not away from it. Upon completion, REX briefly ran (as intended) at near full capacity from west to east. But very quickly the rise of Appalachia gas began to push back Rockies supply. Certain key regulatory rulings allowed REX to respond to this with a partial reversal, resulting in the pipeline being fed from both ends and converging south of Chicago. Today, through bidirectional flow, REX transports natural gas from major supply basins in the Rocky Mountain and Appalachian regions to demand centers across a vast segment of North America. After

Figure 2-47. *Gas Infrastructure Buildout in the Rockies, 2008-2011*

further investment, today REX has the capacity to move 2.6 BCF/D from east to west and 1.8 BCF/D from west to east.[39]

> ***Finding:*** Pipelines and their shippers have to make a long-term commitment (20 to 30 years) based on the size and location of production areas and market areas at the time of investment, in an industry that is undergoing rapid dynamic changes in both. The history of the REX pipeline highlights one of the most significant challenges of infrastructure investment.

d. Infrastructure Development since 2008: The Gulf Coast

Shale development began with the Barnett Shale around Fort Worth, Texas. As the technology was proven in Barnett, the next step was radically accelerated development in the Haynesville Shale in northwestern Louisiana in 2008-2010. As had happened in the Rockies, supply overwhelmed takeaway capacity and drove local prices down. The result was the development of pipeline projects to move the gas out of the production areas, largely into the major long-line systems to the Northeast—at the time the premium market in the country. Some of the key projects were CenterPoint's Carthage-to-Perryville (Line CP), CenterPoint/Spectra's Southeast Supply Header (SESH), Boardwalk's Gulf Crossing Pipeline (GCP), and Kinder Morgan's Midcontinent Express (MEP), joined by multiple pipelines within Louisiana (Figure 2-48).

However, as these projects were being developed, the world was changing. By the end of 2011, Appalachian natural gas production was surging, up from 1.6 BCF/D in 2008 to 7.8 BCF/D in 2011, having the same effect on the long-line systems as it had on REX. Local Northeast volumes were beginning to supply the Northeast demand

39 Tallgrass Energy, "Rockies Express Pipeline," https://www.tallgrassenergy.com/Operations_REX.aspx (accessed October 5, 2019).

markets, reducing the need to transport natural gas from faraway production areas. Natural gas was entering pipelines in Pennsylvania and West Virginia from the Marcellus, rather than traveling over 1,000 miles from Texas or Louisiana. This reduced flows up the long-line systems from the South such as Transco, Texas Eastern, and Tennessee Gas pipelines, impairing the market for Barnett and Haynesville gas, and causing market prices to fall to levels that would no longer support development in the relatively higher-cost Haynesville Shale.

e. *Infrastructure Development Since 2008: Appalachia*

The Northeast has been historically the largest natural gas demand region in the United States. It has now become the predominant supplier of domestic gas supply. The ripple effect on natural gas pipeline infrastructure extends in every direction (Figure 2-49).

Northeast gas production has surged past 30 BCF/D as major pipeline takeaway capacity has become available. Northeast gas production now accounts for one-third of all U.S. natural gas supply, up from just 3% of supply in 2008. The Northeast has been transformed into a net exporter into both the southern and midwestern United States, as well as Eastern Canada. By the end of 2018, Appalachian pipeline capacity finally caught up with production after takeaway capacity from the region was expanded by 20.9 BCF/D. But this balance is expected to last for only the next several years. The combination of average local demand and outbound takeaway capacity from Appalachia reached about 30 BCF/D. This combination is expected to increase to about 38 BCF/D by 2021, which may be adequate to meet the

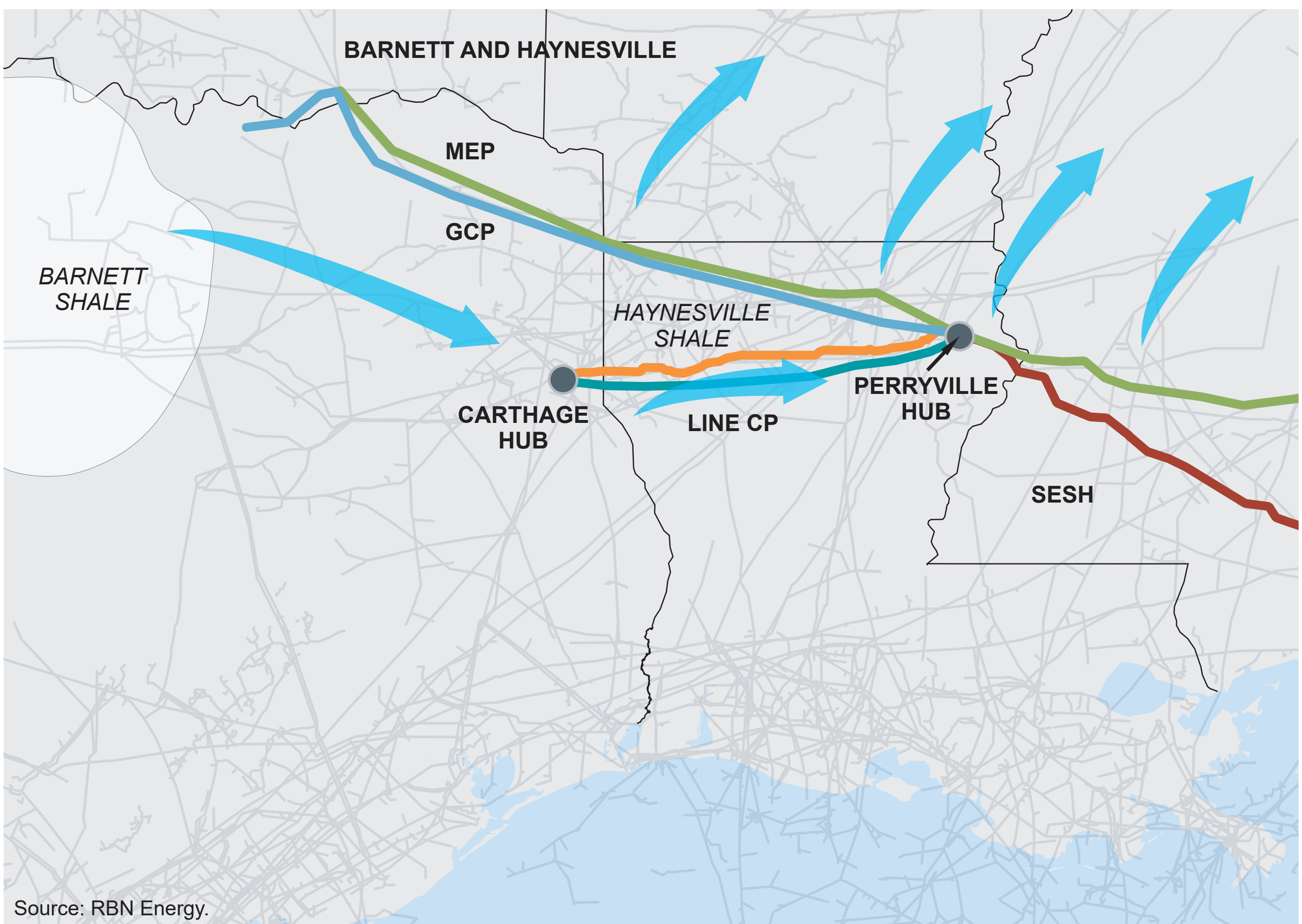
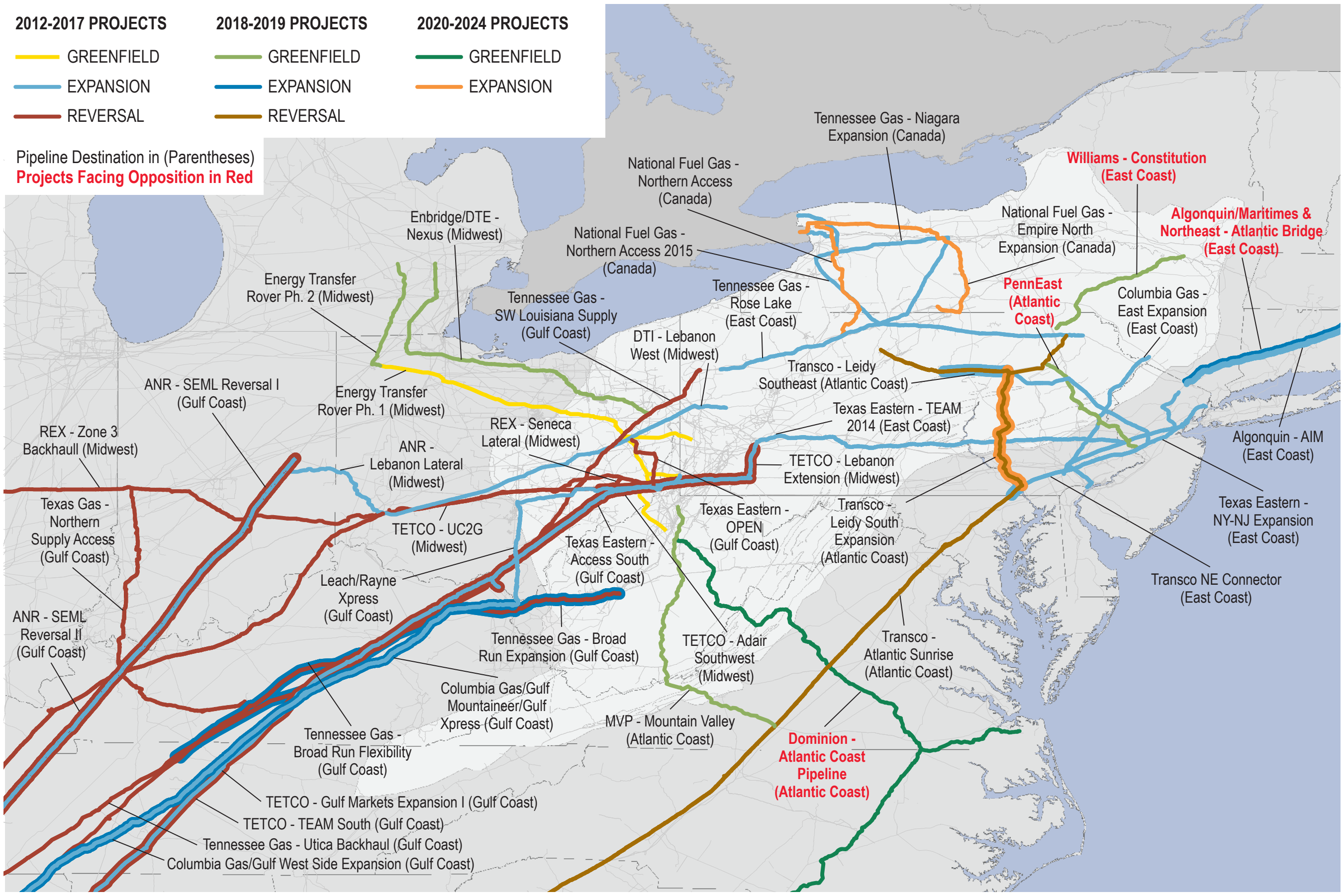


Figure 2-48. *Gas Infrastructure Buildout in the Gulf Coast, 2008-2011*



Source: RBN Energy and PennWell - MAPSearch.

Figure 2-49. *Natural Gas Pipeline Projects from Appalachia, 2012-2024*

expected increase of Marcellus/Utica production growth into the mid-2020s. To date, most of the substantial growth in pipeline capacity needed to accommodate these profound changes involved the reuse of existing pipelines—either reversing the flow direction or expanding the pipelines' capacity. Recently more costly and impactful greenfield pipelines have been required. Projects to deliver Appalachian natural gas to the Atlantic Coast, East Coast, and Canada may provide approximately 5 BCF/D in new natural gas takeaway capacity. Many of these projects are encountering a more difficult regulatory and permitting environment. For example, the Mountain Valley Pipeline and Atlantic Coast Pipeline projects have encountered lawsuits following the receipt of certificates of public convenience and necessity by FERC and have yet to progress with implementation. Meanwhile, the Atlantic Sunrise Pipeline experienced a delay due to stakeholders' objections to the pipeline's proposed route after FERC issued a certificate of public convenience and necessity.[40]

In the early years of the Appalachian capacity buildout, outbound capacity constraints resulted in a large oversupply in the region, which in this case drove the region's prices very low. As shown in Figure 2-50, Appalachian gas prices (represented by Dominion South price basis compared to Henry Hub) that had for decades demanded a premium over other supply areas traded at deep discounts.

The loss of the historical premium in the Northeast market has driven the wave of pipeline developments from Appalachia to access

40 Lancaster Against Pipelines, "Judge Declines to Give Atlantic Sunrise Pipeline Builder Immediate Possession of Nuns' Land," July 7, 2017, http://www.wearelancastercounty.org/_judge_declines_to_give_atlantic_sunrise_pipeline_builder_immediate_possession_of_nuns_land.

markets in the Gulf Coast, reversing the longstanding net flow of natural gas from the South to Appalachia.

As takeaway capacity from Appalachia has improved in 2018 and early 2019, the deep discounts initially created by the oversupply of gas have eased, but prices remain at a discount to the Gulf Coast, creating lower prices for consumers throughout the Northeast than were previously realized prior to the development of Appalachia gas supplies.

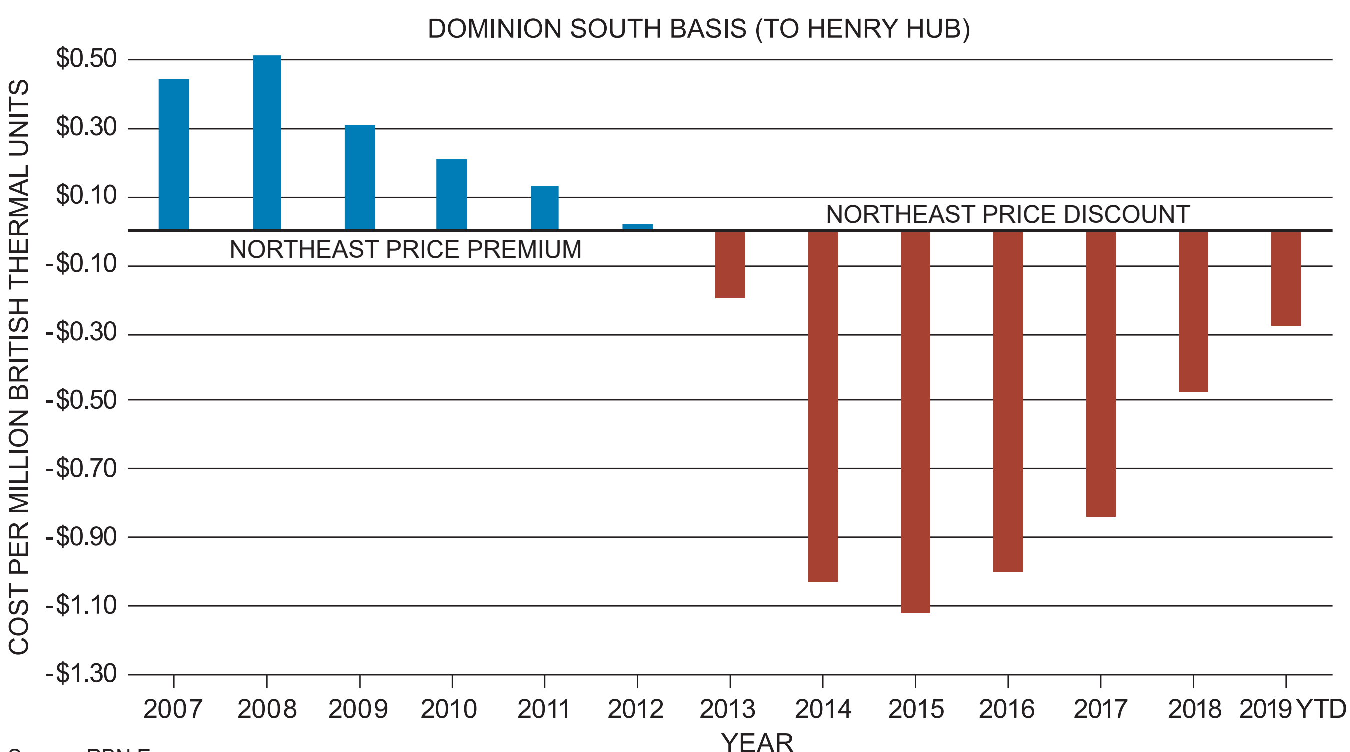
f. Appalachia Infrastructure — Ohio to the Gulf Coast

As Appalachian supply surged past Texas and Louisiana shale natural gas production, flows from the long-line pipelines from the South slowed then stopped as Northeast markets came to be supplied with Northeast gas. Northeast gas was sold to customers in the South by using displacement transactions (backhauls) across the pipelines that did not require significant new long-line pipeline construction.[41] But by 2012, it was clear that natural gas actually had to physically flow south, rather than just satisfying the Northeast region or displacement markets. Fortunately, demand markets (including LNG exports) were ramping up in the Gulf Coast region. This resulted in 12 new pipeline projects to move natural gas from Appalachia to the Gulf Coast down the Ohio Valley, increasing southbound takeaway capacity from near zero to more than 6 BCF/D by the end of 2017. These natural gas pipeline projects, depicted in Figure 2-49, proved critically important to the ability of Appalachian gas to exit the region.

In 2018 and 2019, three more Ohio Valley projects totaling 2.6 BCF/D of additional takeaway

41 In pipeline transportation, the substitution of a source of natural gas at one point for another source of natural gas at another point. Through displacement, natural gas can be transported by backhaul or exchange. In natural gas marketing, the substitution of natural gas from one supplier of a customer with natural gas from another competing supplier.

Interstate Natural Gas Association of America, "Displacement (Gas)," https://www.ingaa.org/about/34/1867.aspx.



Source: RBN Energy.

Figure 2-50. *Appalachia Gas Price Developments, 2012-2019* capacity to the Gulf Coast have been completed. These additional pipeline projects, depicted in Figure 2-49, include TGP's SW Louisiana Supply and TGP Broad Run expansion, as well as Columbia Gulf's Gulf Xpress.

The Gulf Coast was not the only market seeking natural gas supply from Appalachia. Increased pipeline access to the Atlantic Coast began in 2017. The first was a pipeline expansion of the Transco Leidy Southeast pipeline. Columbia Gas' WB Xpress project also increased deliveries to Atlantic markets by 0.5 Bcf/d in late 2018. Transportation down the East Coast has moved forward with other major projects—one that has succeeded and one that is pending. Transco's Atlantic Sunrise project is a major addition to the market, moving 1.7 BCF/D away from Marcellus, dropping 0.85 BCF/D of that gas off in Maryland to supply the Cove Point LNG export terminal and carrying the other 0.85 BCF/D all the way to the Gulf Coast. Atlantic Sunrise went into service in 2018. EQT's Mountain Valley Pipeline has received FERC approval and has been slated to move 0.5 BCF/D out of Marcellus/Utica into an interconnection with Transco in Virginia. It had been planned to go into service in 2019, but has thus far encountered multiple permitting delays, leading to uncertainty as to its completion date.

Looking ahead, two more major projects seeking to add 2.1 BCF/D in natural gas pipeline capacity from Appalachia are expected to move forward. Transco plans to expand its Leidy South line by 0.6 BCF/D in the third quarter of 2020. Dominion is seeking approvals for the Atlantic Coast Pipeline, designed to move 1.5 BCF/D from West Virginia to North Carolina, with service to Virginia Beach along the way, planned for service in 2021. The Atlantic Coast Pipeline remains subject to numerous legal and regulatory challenges.

In addition to going south and southeast, Appalachian takeaway capacity also has been built out to the west, into the midcontinent. As previously discussed, an early major step in this effort was the successful reversal of the eastern section of REX. Appalachian takeaway capacity to the Midwest from 2012 to 2017 increased by 4.7 BCF/D through a combination of lateral pipelines, extensions of existing pipelines, and backhauls. During this period, the construction of Rover Phase I was noteworthy as the first major greenfield pipeline out of the region, signaling that the era of low-cost, low-impact conversion of existing pipelines was drawing to an end.

Two additional projects were completed in the 2018 to 2019 timeframe to the MichCon/Dawn (Canada) market. Rover Phase II both increased Rover's capacity from 1.7 BCF/D to 3.25 BCF/D and finished the extension from Ohio to Michigan. Nexus, another greenfield project following a route similar to Rover's, brought an additional 1.5 BCF/D of capacity from Appalachia to the already-constrained MichCon/Dawn market. The introduction of these two major supply sources into the Dawn Hub caused a cascade of oversupply into MichCon, then west into Chicago. And as this oversupply reaches the midcontinent, it competes with Rockies and Permian Basin gas that cannot yet reach Gulf Coast markets. Until sufficient midcontinent takeaway capacity can be in place to relieve these constraints, supplemented by sufficient capacity to allow Permian Basin gas to serve southern markets, Appalachian production will not have full access to Gulf Coast markets.

g. Appalachia Infrastructure — Successful Projects to the East

From 2012 to 2017, six successful projects aimed at increasing takeaway capacity from Appalachia to the East Coast were completed, adding 2.4 BCF/D from the basin. All of these projects were expansions of existing systems and therefore able to take advantage of the economics of legacy facilities. These projects included TETCO's NY/NJ Expansion (0.8 BCF/D) and TEAM (0.6 BCF/D), TGP Rose Lake (0.2 BCF/D), Transco NE Connector (0.1 BCF/D), Columbia Gas Eastside Expansion (0.3 BCF/D), and Algonquin AIM (0.3 BCF/D).

Three additional major projects totaling 1.9 BCF/D were proposed to enter service in 2018 to 2019, but their completion dates remain uncertain in late 2019 due to legal and regulatory challenges. These projects are the PennEast Pipeline (1.1 BCF/D), Williams Constitution (0.7 BCF/D), and Algonquin/MNE Atlantic Bridge (0.1 BCF/D).

The PennEast and Constitution pipelines are greenfield projects and continue to face stiff opposition from various nongovernmental organizations and state regulatory agencies. The Atlantic Bridge Project is designed to increase natural gas reliability into the New England area, a region which still deals with natural gas price spikes and supply availability issues during winter cold snaps. The Northeast consuming states, largely led by New York, have been especially difficult for project development, even after FERC approvals have been received. In particular, the withholding of Clean Water Act Section 401 certifications by state authorities (necessary to gain U.S. Corps of Engineers approval) has been a recent tactic used to frustrate pipeline development.

Two major projects not shown here, Kinder Morgan's Northeast Energy Direct and Enbridge's Access Northeast, would have relieved New England capacity constraints, but were canceled for lack of subscription by regional customers. This was driven in part by market structures in New England that limit binding commitments for long-term natural gas supply by electric utilities. More details on New England market structures are given in the topic paper, "Gas/Electric Coordination Issues and Natural Gas Pipeline Deployment."

New York, despite perennial winter shortages, is pursuing a number of policies to prevent pipeline construction, in part relying on long-term plans to eliminate natural gas use for power generation. For example, in May 2019, New York's Department of Environmental Conservation issued a denial to Williams for its proposed Northeast Supply Enhancement (NESE) project.[42] Shortly thereafter, National Grid said that it would not process new applications for natural gas service in its New York City and Long Island service areas until the NESE pipeline receives the permits it needs to proceed.[43]

42 French, M. J., "Cuomo administration rejects Williams pipeline," May 15, 2019, *Politico*, https://www.politico.com/states/new-york/albany/story/2019/05/15/cuomo-administration-rejects-controversial-williams-pipeline-1017327 (accessed September 1, 2019).

43 Reuters, "National Grid says no new NYC natgas customers without Williams pipeline," May 17, 2019, https://www.reuters.com/article/us-national-grid-williams-new-york-pipel/national-grid-says-no-new-nyc-natgas-customers-without-williams-pipeline-idUSKCN1SN2GW (accessed September 1, 2019).

Finding: The closest and previously highest-value consuming region, New England and New York, has been unable to get the natural gas pipeline capacity it needs due to a combination of opposition to pipeline projects and market structures that have hindered long-term shipper capacity commitments.

Since the start of 2015, 0.30 BCF/D of pipeline capacity from Appalachia has been developed to the Canadian market in southern Ontario including National Fuel Gas's Northern Access 2015 (0.14 BCF/D) and TGP Niagara (0.16 BCF/D). Other projects were proposed, but not sufficiently subscribed to be built. These flows into southern Ontario have disrupted the traditional flow of natural gas supplies into Ontario and Quebec from Western Canada, along the TransCanada (now TC Energy) system and the Great Lakes system through Michigan. One result of this disruption has been a heavy concentration of both pipelines on the Dawn Hub as a destination, exacerbating the congestion at Dawn discussed earlier. From 2020 to 2024, two additional projects are planned to increase takeaway capacity to Canada by 0.71 BCF/D. These are Empire Northern Expansion (0.21 BCF/D, 4Q 2020) and Northern Access (0.50 BCF/D, 1Q 2021). If completed, this new capacity will further push back on Western Canadian supplies, forcing them back to the midcontinent to join the large oversupply situation there.

h. Infrastructure Buildout Since 2008: Permian Basin

In the same timeframe as pipelines were being built to take Appalachian gas south and west, still more natural gas production started to flow into the market from gas associated with crude oil production, which was increasing from the Bakken and Eagle Ford, and eventually from the Permian Basin. Although it was once one of the most mature supply areas in the nation, application of shale (tight gas) technology in the Permian Basin has created a significant supply of oil and associated natural gas. Ultimately, the Permian Basin became by far the dominant new supply area. As crude oil pipelines were built out, crude oil production grew, which also increased volumes of associated gas, adding to the oversupply. This associated gas also was high in NGL content, which increased volumes of NGL production. Permian Basin natural gas production grew faster than any basin in the United States other than the Marcellus/Utica. Natural gas pipeline takeaway capacity was more than adequate in 2017, but by 2018, capacity was fully utilized. Due to oversupply in the region, Permian Basin gas prices fell dramatically, ultimately trading negative for many days during 2019 (see Figure 2-51).

Permian Basin natural gas supply is the foundation for exports to Mexico and for multiple LNG export projects, but it requires a considerable buildout of pipeline capacity of pipelines across Texas. As of August 1, 2019, three new pipelines reached Final Investment Decisions (FID) and are being developed to transport up to 6 BCF/D of Permian Basin natural gas to the Gulf Coast.[44] These

44 As of July 1, 2019, these projects include Kinder Morgan's Gulf Coast Express, Kinder/EagleClaw's Permian Highway Pipeline, and WhiteWater Midstream/MLPX/Stonepeak Whistler Pipeline.

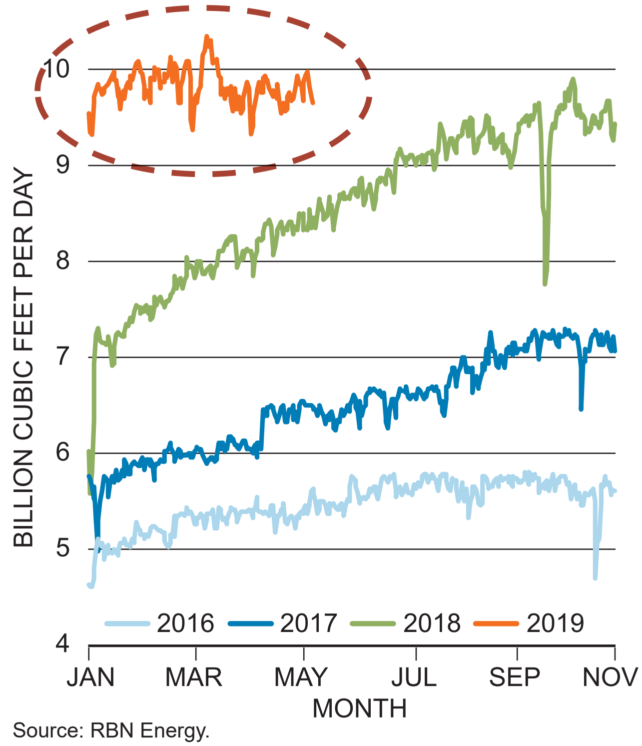


Figure 2-51. *Permian Basin Natural Gas Production*

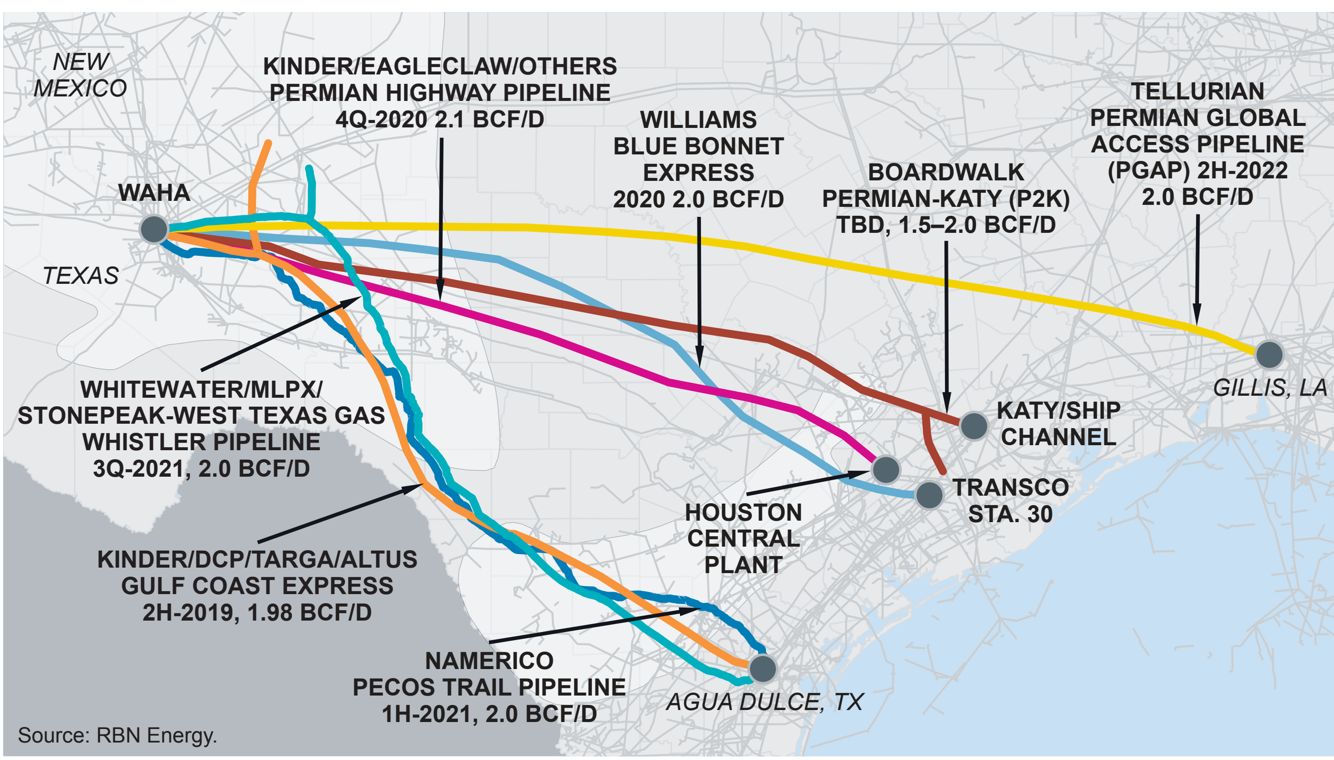


Figure 2-52. *Permian Basin Gas Takeaway Pipelines, 2019+*

projects may be joined by additional announced projects that have not yet reached FID, including Namerico Pecos Trail Pipeline, Williams Blue Bonnet Express, Boardwalk Permian-Katy, and Tellurian Permian Global Access Pipeline. These projects are all pictured in Figure 2-52.

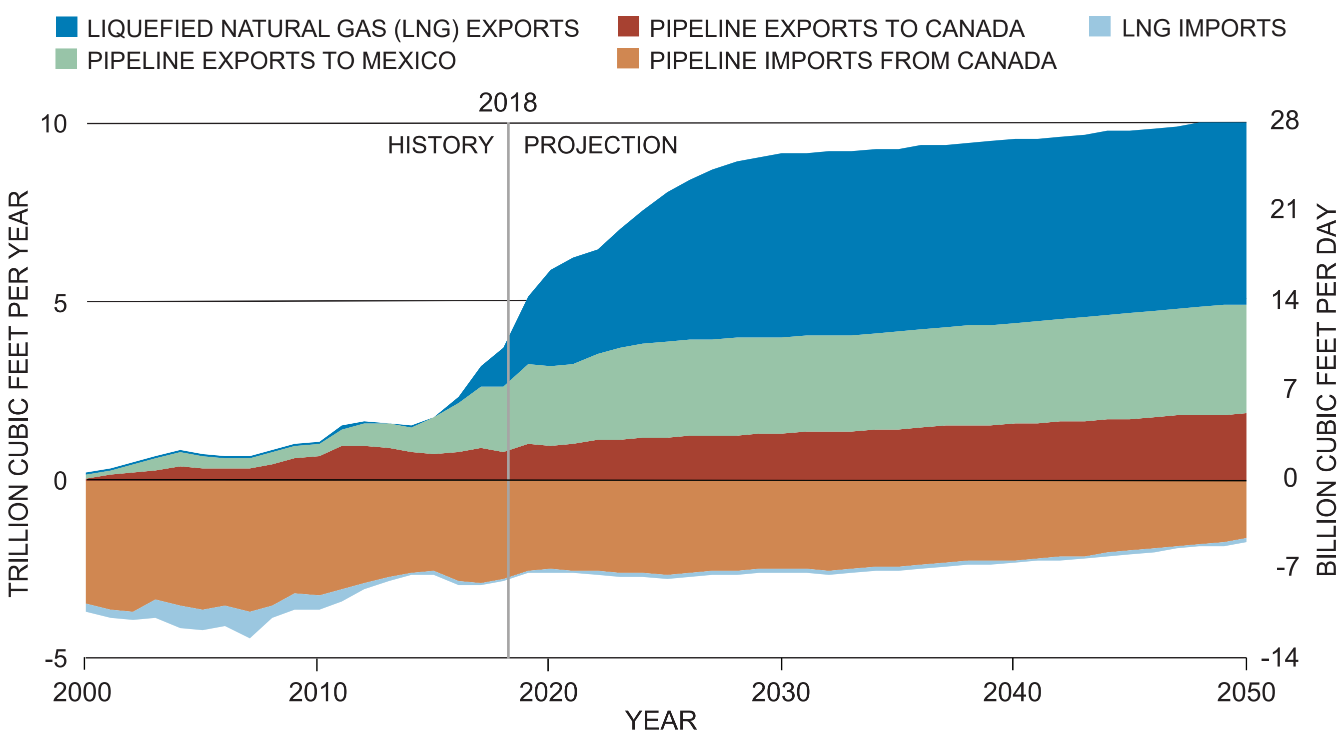
It is critical that all of these projects proceed as planned and on time to ensure that the Permian Basin has sufficient gas takeaway capacity, allowing further growth in crude oil, natural gas, and NGL production from the Permian Basin and Gulf Coast LNG export projects to meet their startup expectations and contractual commitments. Increasing opposition from landowners and other stakeholders could hinder development.

5. Exports — Natural Gas

U.S. natural gas production now exceeds domestic demand and is expected to grow faster than domestic demand for the foreseeable future. Thus, the bulk of the expected production growth will be exported. The Canadian market is fully supplied, both from its own resources and from a degree of cross-border exports from the Northeast United States, so the primary available destinations for growing production are exports to Mexico by pipeline and to the rest of the world by LNG (Figure 2-53 and Figure 2-54). Additional pipeline infrastructure to and within Mexico can increase export capacity while additional LNG export facilities will further increase LNG export capacity.

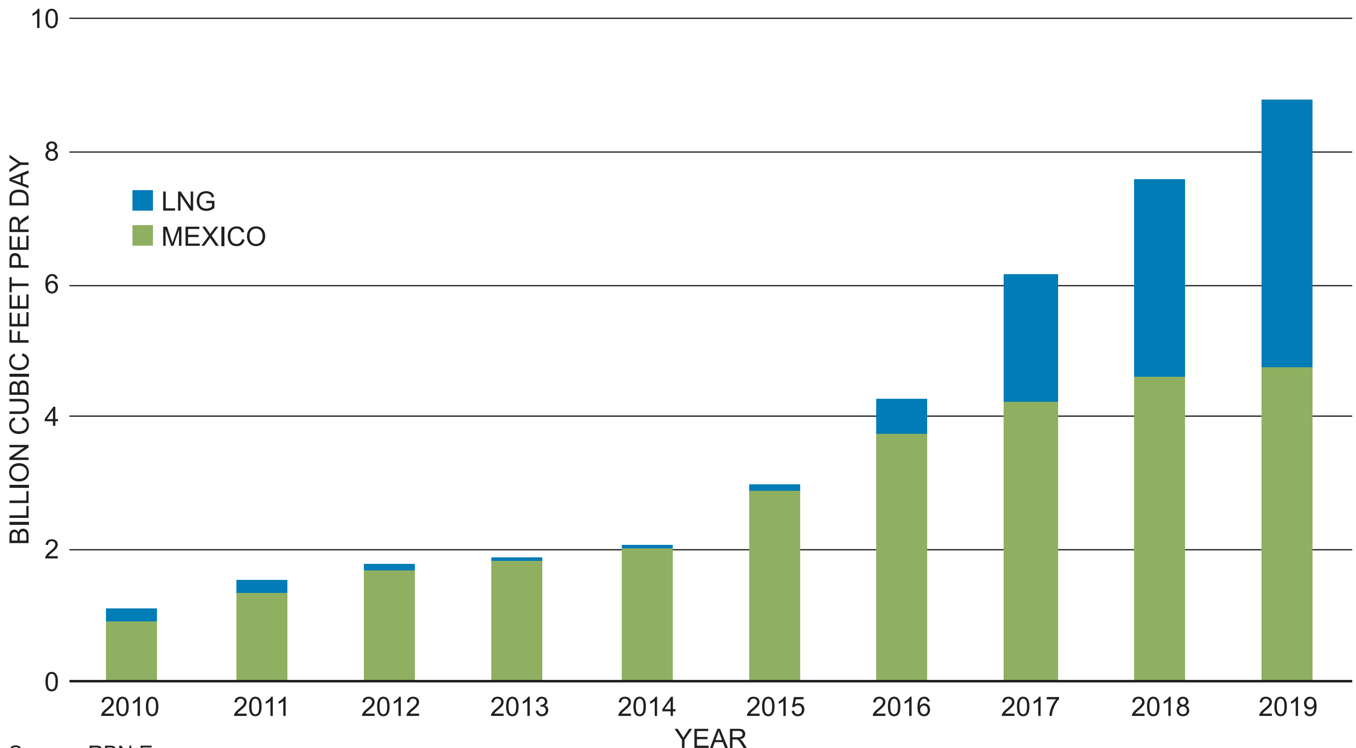
a. Natural Gas Pipeline Exports to Mexico

The United States and Mexico have had a longstanding natural gas supply relationship, with relatively modest volumes of natural gas flowing both ways across the border, depending on the location of supplies and demand. U.S. exports to Mexico have sharply increased over the last decade as Mexico's own domestic production has waned. At the same time, major growth in Mexican gas-fired power generation as a result of the country's 2014 energy reform has combined with surging Texas supply to make nearby Mexican markets a major destination for U.S. supply, resulting in multiple



Source: EIA, *Annual Energy Outlook 2019*.

Figure 2-53. *Natural Gas Trade*



Source: RBN Energy.

Figure 2-54. *Natural Gas Surplus*

cross-border pipeline projects from the Permian Basin and South Texas into both central and eastern Mexico.

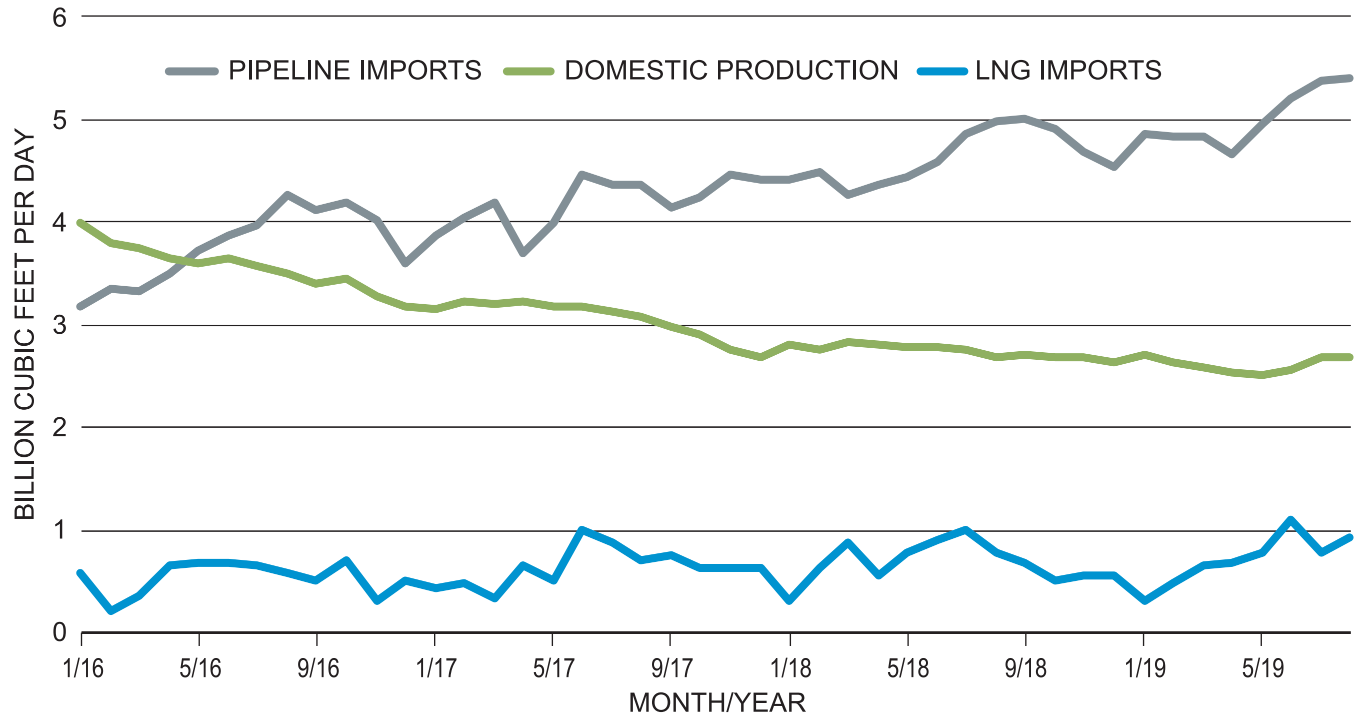
Exports from the United States to Mexico have ramped up sharply, from less than 1 BCF/D as recently as 2010, to nearly 5 BCF/D today, with potential for much higher levels as new infrastructure becomes available (Figure 2-55). Meanwhile, Mexico meets remaining natural gas demand with LNG imports, much of which also come from the United States (Figure 2-56).

The key to the Mexican gas market is that the major U.S. supply growth is in West Texas, which will feed central Mexico primarily from the Waha Hub in the Permian Basin, while the major Mexican consuming markets are in eastern Mexico, fed either by internal Mexican pipelines that carry natural gas from west to east, or by cross-border pipelines from Agua Dulce in Southeast Texas (Figure 2-57). Infrastructure is constrained, both across Mexico and into Agua Dulce, creating a major need for infrastructure in both countries. In the United States, the primary supply is Permian Basin gas, some of which is able to cross the border in the west and then move east across Mexico. To make this supply a more robust source for eastern Mexico, major pipelines are being developed to move natural gas from West Texas to Agua Dulce.

b. Natural Gas LNG Exports

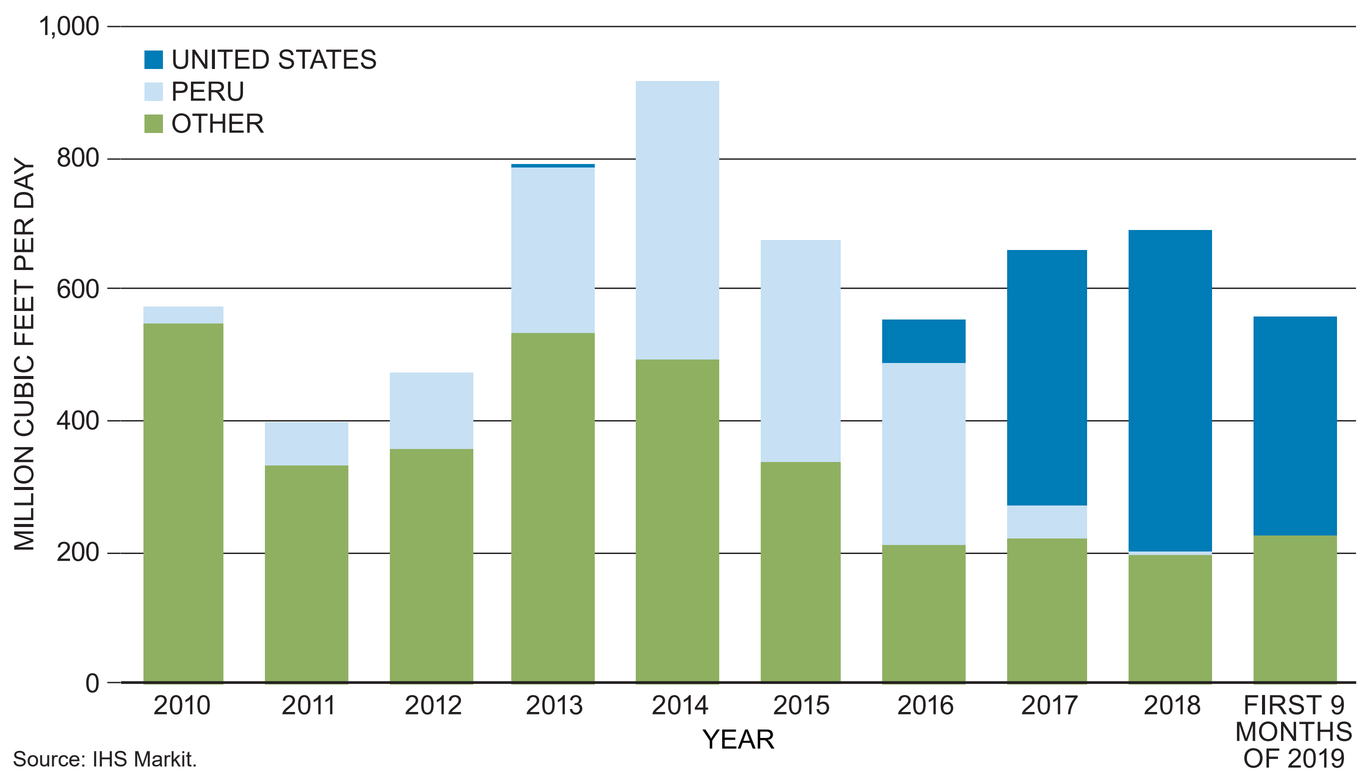
As previously described, the U.S. LNG industry has been transformed by domestic natural gas abundance. Over the span of 15 years, the United States has pivoted from being an LNG importer to an LNG exporter. Beginning in 2016, Cheniere's Sabine Pass (3.0 BCF/D), originally intended as an import terminal, became the first U.S. LNG export terminal in the U.S. Lower 48 and has seen its capacity and exports rise steadily. Sabine Pass has since been joined by Cove Point (0.7 BCF/D), Corpus Christi (0.6 BCF/D), and Cameron (0.6 BCF/D), placing current operating U.S. LNG export capacity at about 5 BCF/D as of mid-2019.[45] As a result,

45 U.S. Energy Information Administration, "U.S. and International Imports/Exports Data," Natural Gas, https://www.eia.gov/naturalgas/data.php#imports (accessed July 1, 2019).



Source: IHS Markit, data from EIA and Mexico Ministry of Energy, SENER.

Figure 2-55. *Mexico's Natural Gas Supply Mix*



Source: IHS Markit.

Figure 2-56. *Mexico's LNG Imports by Supply Country*

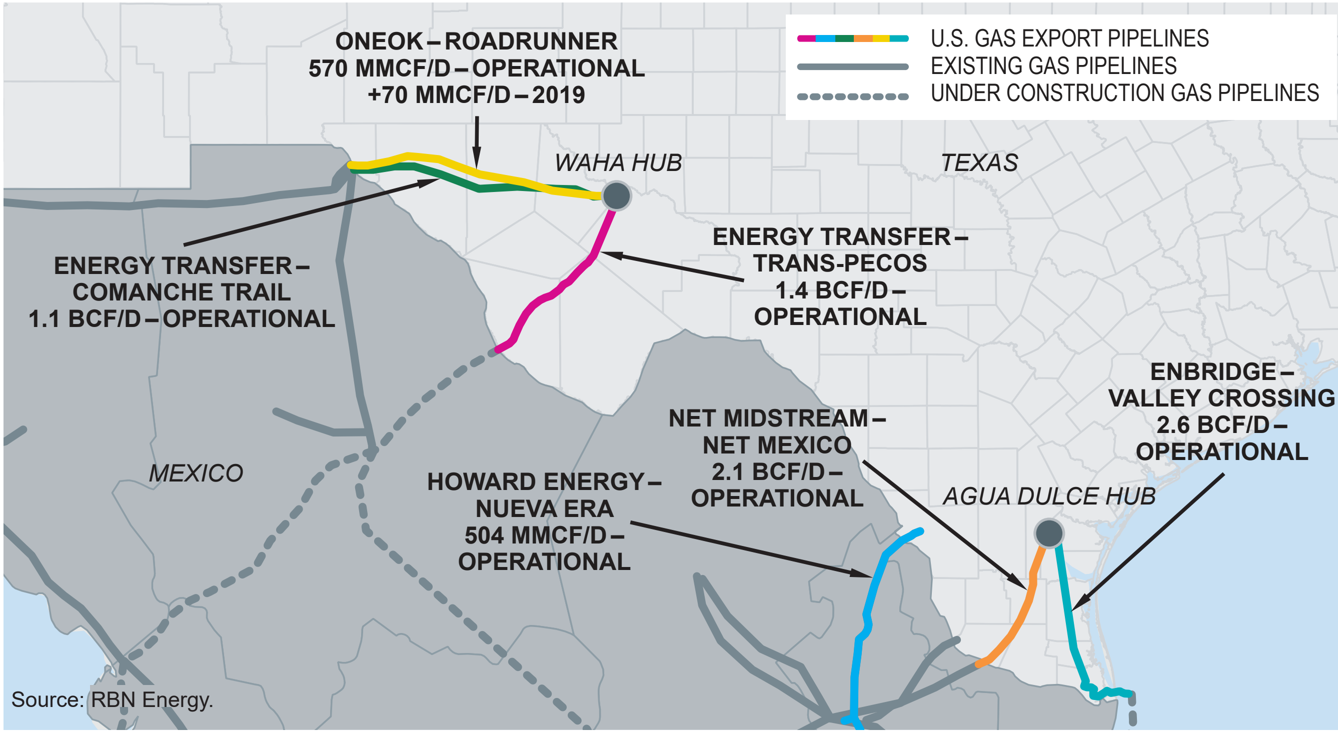


Figure 2-57. *Mexico Natural Gas Pipelines*

LNG exports have risen from 0 to 2.2 BCF/D in 2017, 3.4 BCF/D in 2018, and more than 5 BCF/D in the first half of 2019. Most of that volume has been shipped from Sabine Pass, but the sources are rapidly diversifying.

Future LNG projects will be driven by their competitive costs of supply. Generally speaking, the competitiveness of American LNG hinges on the sum of the following costs as compared to the equivalent amount of LNG delivered from low-cost producers around the world, predominantly in the Middle East and Southeast Asia.

- Cost of upstream production
- Cost of transportation from producing area to liquefaction terminal
- Cost of transportation from the liquefaction terminal to end-user market
- Predictable and transparent regulatory and fiscal framework.

Over the next 2 years, the United States will see a significant increase in LNG export capacity in a short time span, with 5 BCF/D of additional capacity added at five facilities along the Gulf Coast. Most of that capacity will fill up with firm gas supply within a few months of start-up, driving major changes in flow and pipeline capacity. The majority of the pipelines supplying Gulf Coast LNG export terminals are greenfield pipelines crossing Texas and Louisiana.

6. Resiliency — Natural Gas Transportation System

a. Pipelines Resiliency

The vast bulk of natural gas delivery takes place domestically through pipelines, storage, and distribution systems. There are fundamental characteristics of the U.S. delivery system that create inherent resiliency, although the system is not without exposures.

One of the most striking characteristics of the system shown is its sheer size and complexity as described and depicted above. The diversity of locations of supply, storage, directions of flow, and multiplicity of delivery options means that in the event of any outage, the likelihood of being able to work around such outage and maintain service is extremely high, having resulted in a reliability in meeting firm contractual commitments recently measured at 99.79%.[46]

A very important physical characteristic of the system is that the bulk of it is buried, and thus protected from weather. In the journey from production well or import point, to the ultimate consumer, there are relatively few critical facilities that are exposed to hurricanes, tornadoes, etc. Figure 2-58 depicts the delivery path schematically, with all underground facilities designated as green.[47] The resiliency of the natural gas industry during significant weather events is described in the text box titled "Examples of Resiliency to Weather."

b. Vulnerabilities to Damage or Corrosion, Regulatory Oversight

Underground facilities can be vulnerable to ground shifting and other subsurface activity, to accidental or malicious damage, and to corrosion.

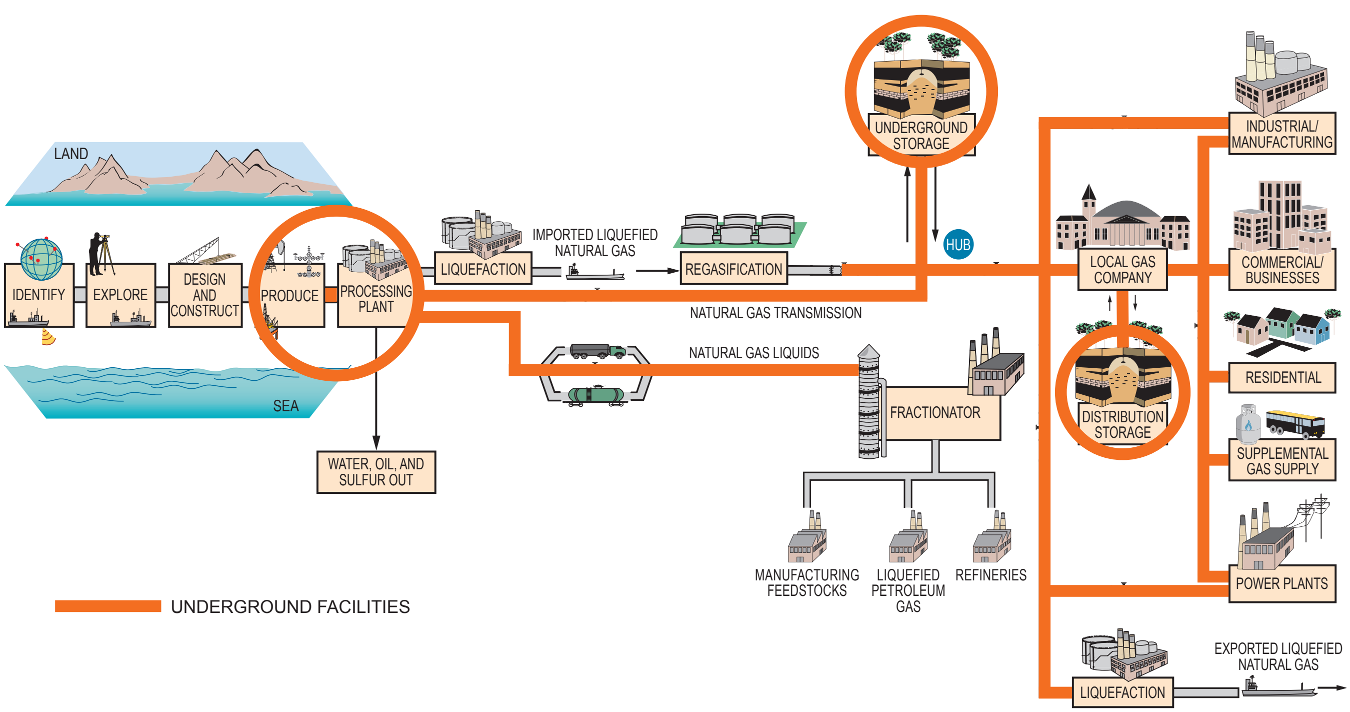
46 Natural Gas Council, Natural Gas Systems: Reliable & Resilient, July 2017, p. 8.

47 Natural Gas Council, *Weather Resilience in the Natural Gas Industry, the 2017-18 Test and Results*, Report prepared for the Natural Gas Council, August 2018.

Protecting the underground natural gas network from such exposures is a major focus of the extensive safety regulatory oversight exercised by multiple agencies.

Federal and state regulatory agencies are vital to the oversight of pipeline industry construction and operating practices. The Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) administers a national program of safety in natural gas and hazardous liquid pipeline transportation, including identifying pipeline safety concerns, developing uniform safety standards, and promulgating and enforcing safety regulations to protect against risks to life, property, and the environment. PHMSA also maintains legislative authority over LNG facilities and underground natural gas storage facilities. Their pipeline safety regulations can be found in 49 CFR Parts 190-199.

PHMSA maintains the primary mission of ensuring the safety of pipeline networks, while the Transportation Security Administration (TSA) is the lead federal agency for pipeline



Source: RBN Energy, on behalf of the Natural Gas Council, based on the American Petroleum Institute *Oil and Natural Gas Industry Preparedness Manual.*

Figure 2-58. *Gas System Schematic*

EXAMPLES OF RESILIENCY TO WEATHER

During the summer of 2017, the U.S. weathered two major hurricane events that both had widespread and serious impacts on multiple sectors of the economy. But neither event had virtually any negative impact on the reliability of natural gas deliveries.

First, in August-September 2017, Hurricane Harvey made landfall in Houston, then stalled, turning into a historic rain event—ultimately depositing nearly 51" of rain in the Houston area and causing devastating flooding, thus immobilizing the heart of the natural gas industry. The event was the costliest natural disaster in U.S. history, with a price tag in excess of $125 billion. Yet pipeline operations continued normally, both within the Houston area and across the broad national footprint of pipelines operated from Houston. The only known outages included a few limited instances of compressor stations that were flooded and thus shut down (but able to be worked around) and many instances of retail gas needing to be disconnected from flooded homes for safety reasons (that is, the gas service was still operable, but the homes were uninhabitable). In addition to the natural physical resiliency accorded by the buried location of pipelines, the extensive success of the industry in distributed commercial operation not requiring employees to be collocated allowed operations to continue normally despite the difficulty of moving forces in place. Key operational forces had already been relocated to emergency operations centers in order to operate the hardened supervisory control and data acquisition and other proprietary systems that required on-site presence.

In September, Hurricane Irma followed, affecting Florida and Georgia. Irma tracked essentially the entire length of the Florida peninsula, disabling 64% of all power in the state because of downed power lines. But gas service into and throughout the state continued normally, such that distributed generation powered by natural gas, for installations such as hospitals, first responders, and other important applications, continued uninterrupted. The only reported gas outages were a limited number of retail services that were disabled because of uprooted trees, but in all cases, they pertained to homes that had been evacuated anyway.

Thus, the overall impact of these two devastating storms was substantial on many sectors, but not on the natural gas industry. The experience demonstrates that the natural gas industry is largely weatherproof.

security. PHMSA works closely with its partners at TSA to ensure pipeline systems are safeguarded. In addition to TSA, PHMSA also works closely with the Department of Energy to monitor energy supply and provide pipeline subject matter expertise.

Finally, the Environmental Protection Agency (EPA)'s emergency management activities and regulations help protect the environment and human health from releases or discharges of oil, chemicals, and other hazardous substances. Through risk management planning, the EPA ensures that operators appropriately prepare for risks associated with operating assets involving hazardous materials.

c. Storage Resiliency

As discussed above, interstate pipelines, marketers, and LDCs rely extensively on natural gas storage. The widespread and important storage network can experience its own issues of resiliency, whether because of equipment failure, well freeze-offs, or field leakage. The highest-profile incident of field leakage in recent years involved Sempra Inc.'s Aliso Canyon facility outside of Los Angeles (Figure 2-59). On October 23, 2015, Southern California Gas Company (SoCalGas) detected a major leak at Aliso Canyon, an underground natural gas storage facility located 30 miles northwest of Los Angeles. The Aliso Canyon storage facility, which has 115 wells, is the second largest natural gas storage field in the western United States. The 86 BCF of working natural gas capacity at Aliso Canyon accounts for two-thirds of SoCalGas' natural gas storage capacity, according to EIA data. Additionally, Aliso Canyon has the largest daily deliverability of all the storage facilities west of the Rockies, estimated at 1.9 BCF/D. After the 2015 leak was detected, the storage level allowed by the California Public Utilities Commission (CPUC) was reduced to 15 BCF, with any further withdrawals requiring regulatory approval. Once Aliso Canyon resumes limited operations, the facility's maximum working gas storage level will be limited to a maximum of 23.6 BCF.[48] Chapter 4, "Technology Advancement and Deployment," provides a detailed description of the Aliso Canyon incident.

48 U.S. Energy Information Administration, "California's Aliso Canyon natural gas storage facility cleared to resume partial operation," *Today in Energy,* July 28, 2017, https://www.eia.gov/todayinenergy/detail.php?id=32252; and California Public Utilities Commission, "Summary on the Operational Constraints at the Aliso Canyon Natural Gas Storage Facility," https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/AC.pdf (accessed October 1, 2019).

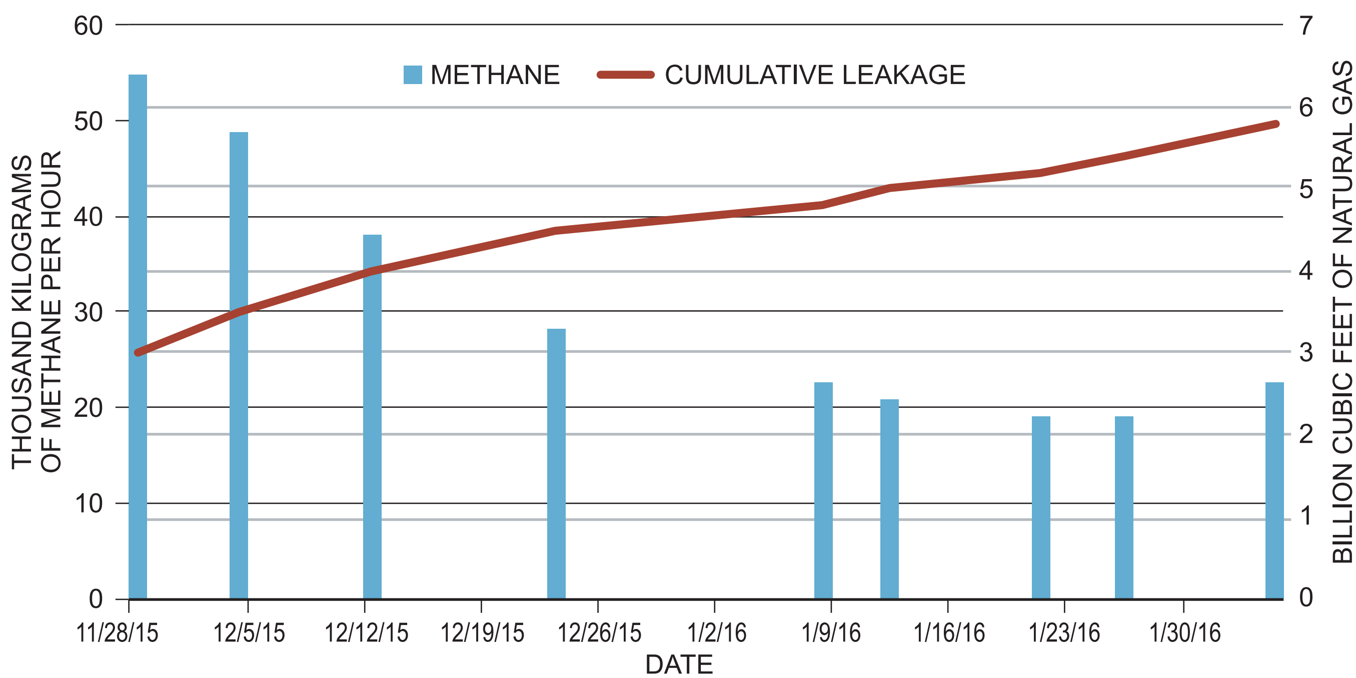
Findings:

- The interconnected nature of the natural gas pipeline network facilitates the competitive marketplace and ensures system and supply reliability.
- Natural gas underground storage is a primary tool in maintaining the resilience of the pipeline system.

E. Natural Gas Liquids Infrastructure History and Current State

1. General Overview of Natural Gas Liquids

Most NGLs are produced at natural gas processing plants, which are usually near natural gas-producing fields. Unprocessed (raw) gas is moved from the well in small-diameter pipeline gathering systems to processing plants, where impurities are removed and NGLs are extracted.



Note: In early December 2015, the well was leaking at a rate of 49,000 (+/- 9,300) kilograms of methane per hour. By early February, the rate had slowed to 23,000 (+/- 3,800).
Source: EIA, *Today in Energy,* February 1, 2016, based on California Air Resources Board.

Figure 2-59. *Natural Gas Leakage Estimates at Aliso Canyon*

Processed gas (called residue gas) is moved to pipelines for delivery to markets. Mixed NGLs (called Y-grade) are transported by pipeline, rail, truck or barge to fractionation facilities that separate the Y-grade into the five NGL purity products: ethane, propane, normal butane, isobutane, and natural gasoline. These products are then moved by pipeline, rail, truck, barge, or ship to end-use markets. This value chain is depicted in Figure 2-60.

2. General Overview of Processing and Fractionation Systems

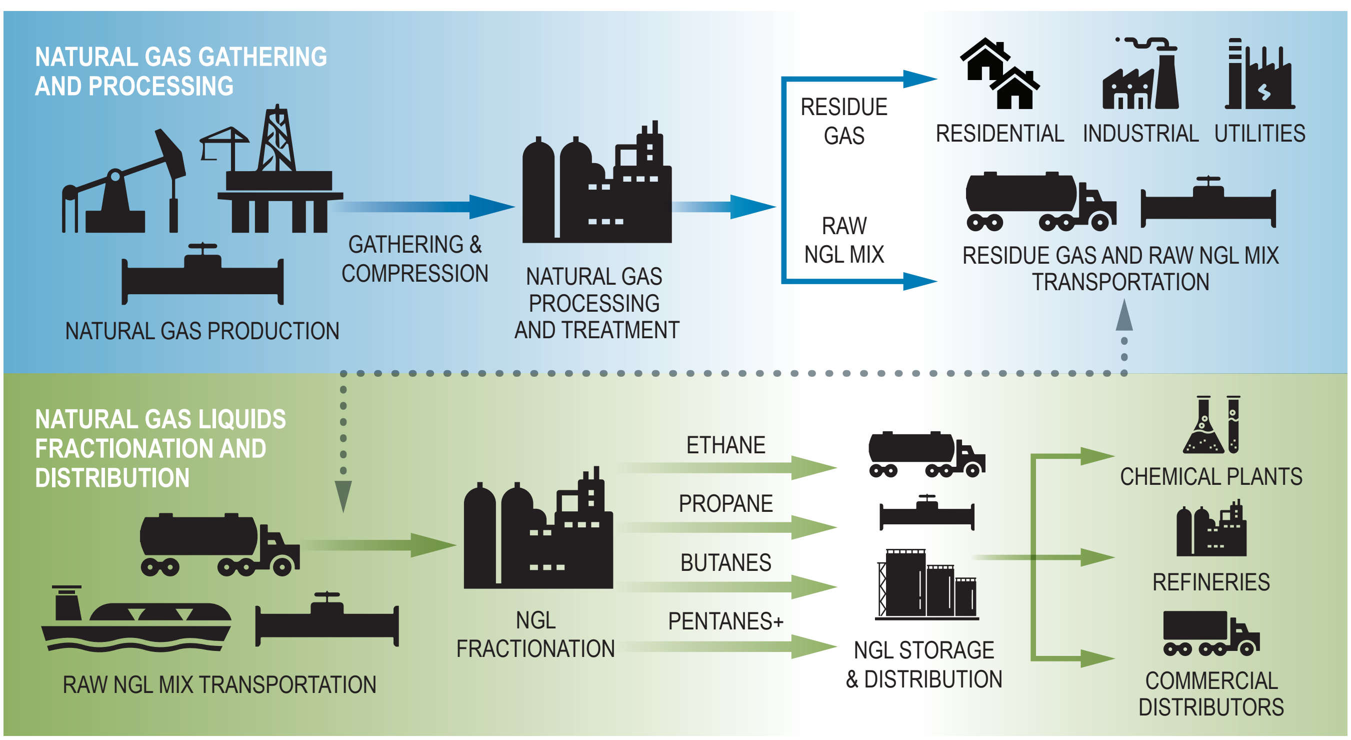
a. *Gas Processing*

There are 600 processing facilities with a capacity of 108 BCF/D. The average production of gas in 2018 was 89 BCF/D. However, only 70% of this production requires processing since it is wet. Dry gas shale plays account for 30% of total U.S. production and shale gas does not require processing.

Since processing plants need to be located near production regions, additional facilities have been necessary because of the geographic shift in gas production. There has been more than a 50% increase in plant infrastructure buildout over the last 10 years.[49] Figure 2-61 shows a map of processing plants and fractionators located throughout the country but primarily in or near producing areas.[50] The Marcellus play and Delaware Basin in the Permian Basin are new areas of production and require new infrastructure. Figure 2-62 shows regional production versus capacity. From a macro regional perspective, there appears to be sufficient capacity for production. However, this can be misleading. For example, in the PADD 3, there is significant under-utilized capacity in Louisiana due to a decline in offshore production. Generally, plant utilization is less than 70%. However, there is significant plant capacity under construction, planned, and proposed in the growth areas.

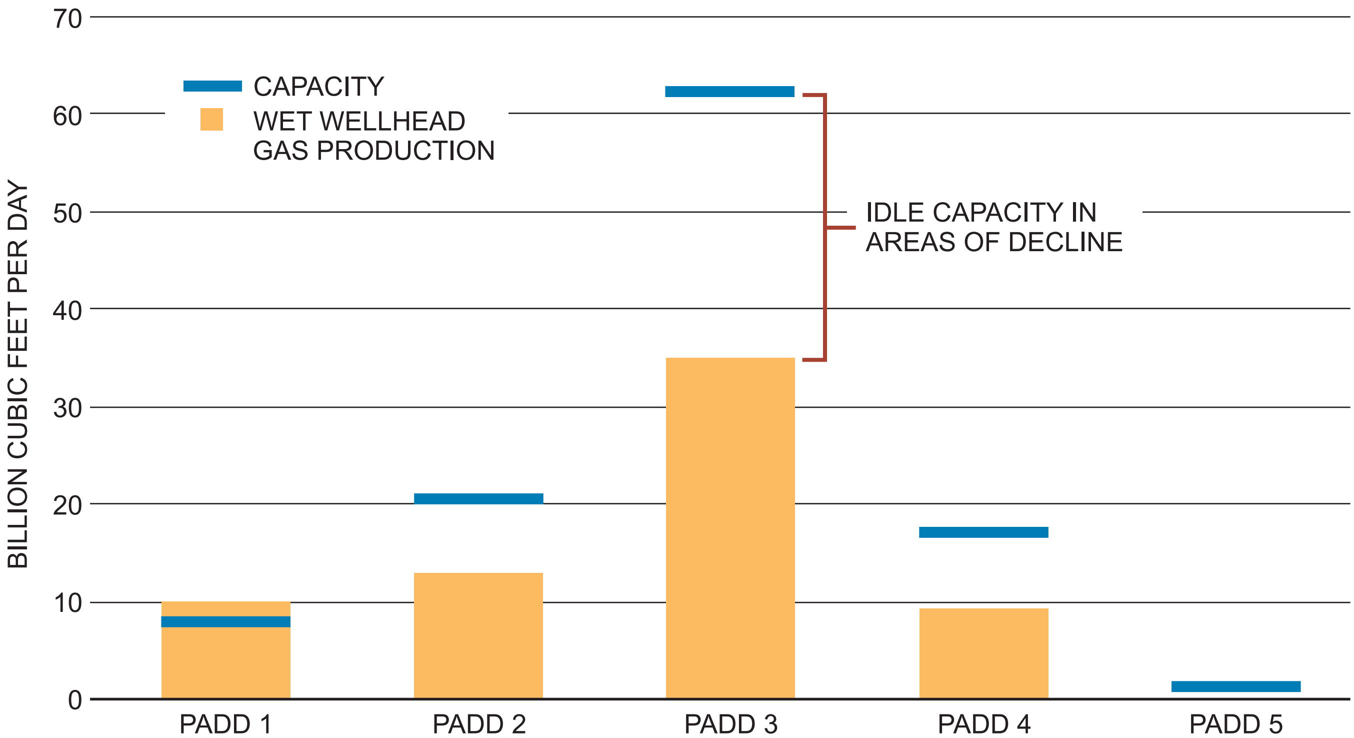
49 U.S. Energy Information Administration, "Natural Gas Processing Capacity in the Lower 48 States," Analysis & Projections, February 14, 2019.

50 S&P Global Platts Analytics, Platt's NGL Facilities Databank, https://www.spglobal.com/platts/en/products-services/natural-gas/platts-ngl-facilities-databank.



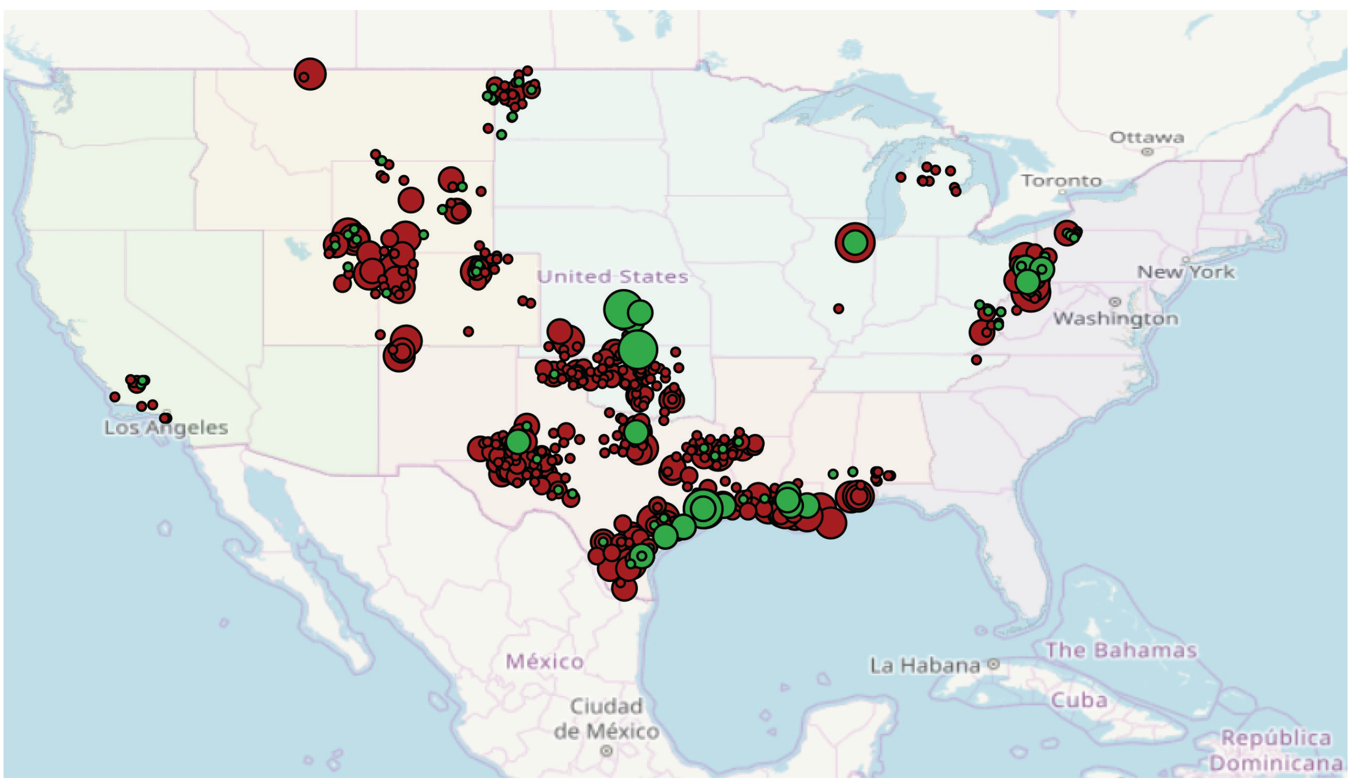
Source: IHS Energy.

Figure 2-60. *Natural Gas Liquids Production Chain*



Source. S&P Global Platts Analytics – NGL Facilities Databank.

Figure 2-61. *Map of U.S. Natural Gas Processing and Fractionation Capacity*



Source: S&P Global Platts Analytics—NGL Facilities Databank.

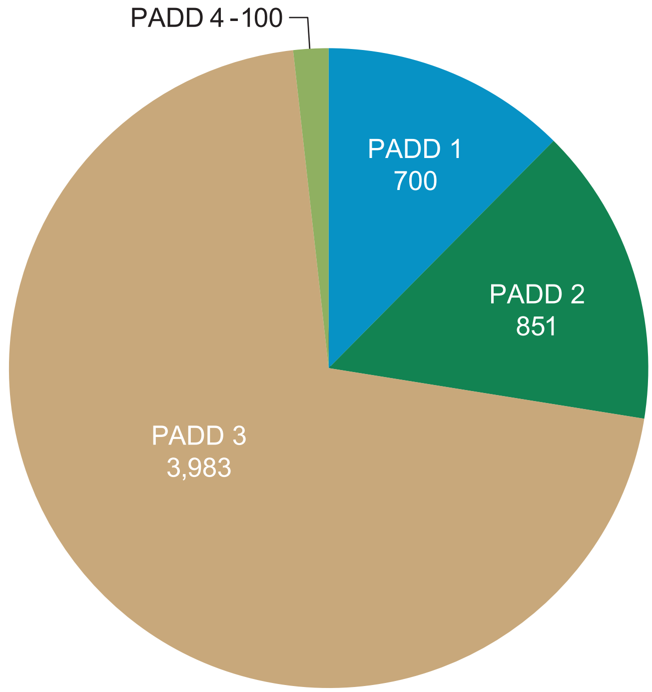
Figure 2-62. *U.S. Natural Gas Processing Capacity by PADD.*

b. Fractionation Systems

Total fractionation capacity (Figure 2-63) in the United States is 5.6 MMB/D, provided at approximately 100 fractionation facilities.[51] At the end of 2018, NGL production was 4.349 MMB/D, suggesting a 90% utilization.[52] Unlike gas processing facilities, fractionation facilities are more concentrated. The three main areas of fractionation in the United States are Mont Belvieu, Texas, Conway, Kansas, and Philadelphia, Pennsylvania. Seventy percent of all U.S. production of NGLs flows to PADD 3 (Texas and Louisiana) for fractionation.[53] More than half of this fractionation activity is in Mont Belvieu, Texas.[54] This location is in proximity to refining complexes, petrochemical plants, and underground storage capacity, and has access to onshore and offshore transportation of purity products to domestic and global markets. As NGL production grew in the major shale basins, pipelines were built to move the Y-grade to fractionation centers, primarily in Texas. As described in the Supply and Demand chapter, domestic supply of NGLs exceeds local demand, giving rise to the export potential of surplus, valuable NGLs from the Gulf Coast to global markets.

By mid-2018, fractionation capacity in Mont Belvieu and other locations throughout Texas was nearly fully utilized. This trend is illustrated by the dashed oval in Figure 2-64. The capacity shortfall occurred as new petrochemical plants using ethane for feedstock were coming online, resulting in market disruption and NGL price spikes.

Responding to the fractionation capacity constraints, several midstream companies announced the construction of new fractionators, both in Mont Belvieu and other locations along the Texas Gulf Coast. Twelve new fractionator trains are planned, for a total capacity addition of 1,620 MB/D, bringing total Texas fractionator capacity to 5,140 MMB/D (Figure 2-65).[55] The constraints being experienced at Mont Belvieu are expected to continue through 2019, when the first wave of new fractionators is expected to come online.



Source: S&P Global Platts Analytics – NGL Facilities Databank.

Figure 2-63. *U.S. Fractionation Capacity*

Although the majority of this new fractionation capacity is planned to come online on the Gulf Coast, specifically at Mont Belvieu, additions in Corpus Christi and Sweeny indicate that the industry is diversifying geographically, while maintaining access to the water.

3. General Overview of NGL Transportation System

a. NGL Pipelines

Pipelines are the most efficient mode to transport large volumes of NGL long distances across the United States and transport almost all Y-grade NGLs, almost all ethane and ethane/propane mixes, some propane, butanes, and gasolines, as well as other refined products to market centers.

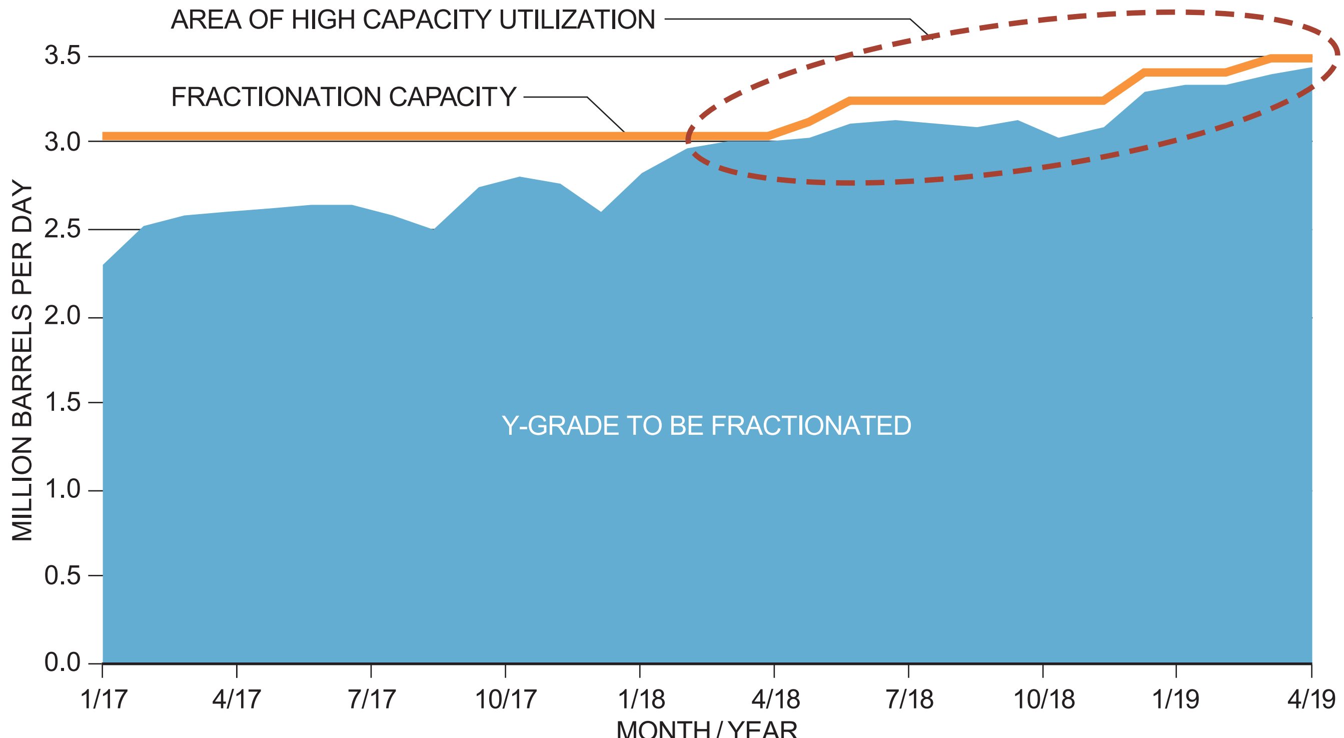
51 S&P Global Platts Analytics, Platt's NGL Facilities Databank, https://www.spglobal.com/platts/en/products-services/natural-gas/platts-ngl-facilities-databank.

52 U.S. Energy Information Administration, "Natural Gas Plant Field Production," Petroleum & Other Liquids, https://www.eia.gov/dnav/pet/pet_pnp_gp_dc_nus_mbblpd_m.htm (accessed July 1, 2019).

53 RBN Energy.

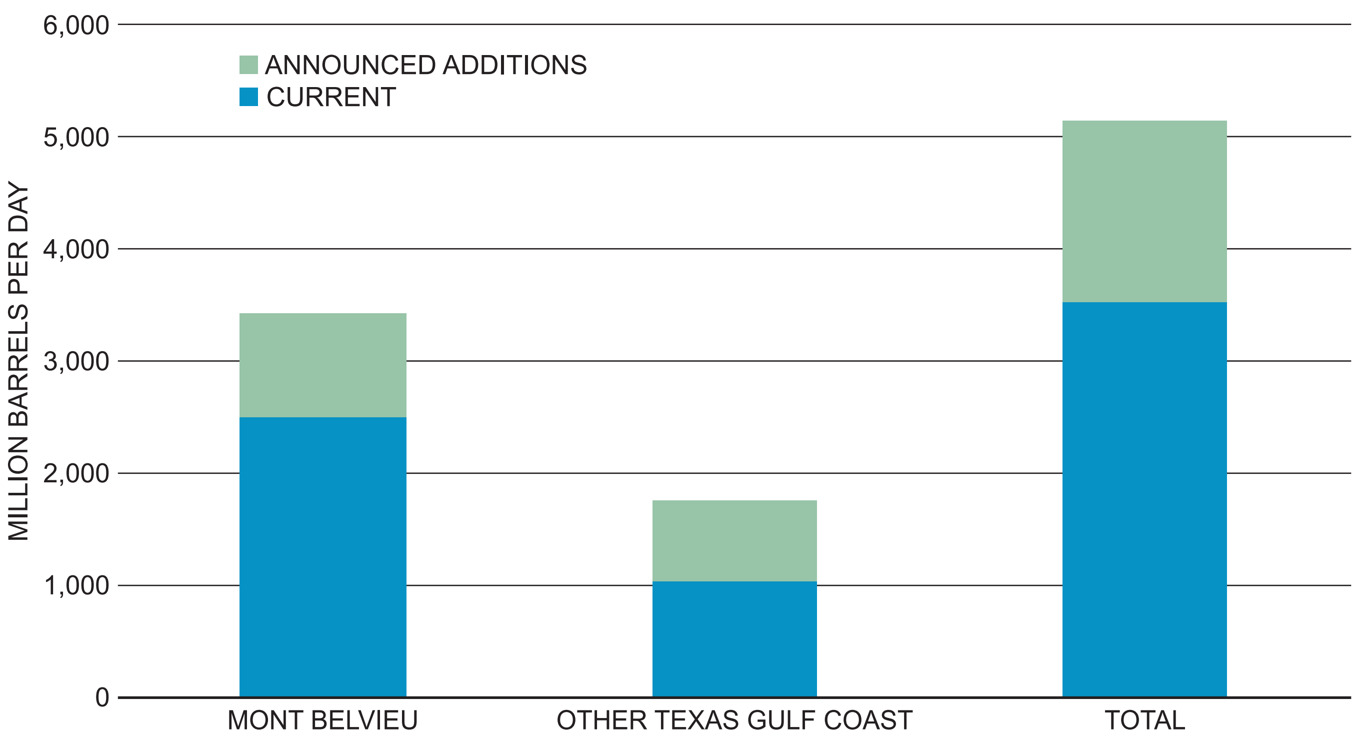
54 RBN Energy.

55 RBN Energy.



Source. RBN Energy.

Figure 2-64. *Texas Fractionation Capacity through 2019*



Source. RBN Energy.

Figure 2-65. *Texas Gulf Coast Fractionation Capacity Additions, 2019 to 2021*

Pipelines are the preferred option to transport ethane and Y-grade NGLs since high pressures are required to keep these hydrocarbons in the liquid state. Pipelines can be dedicated to a single product but can also be used to batch multiple NGL purity products in the line to meet market needs. Batching is the practice of transporting different products at different times in the same pipeline. This practice typically increases the utilization of the pipeline and ultimately reduces transportation costs. Batching may require additional storage at the supply and demand locations to maintain operations when batching operations temporarily prevent access for specific products. Pipelines may receive the NGL from multiple modes including truck, rail, marine, processing plant, or fractionator.

The United States has 4.4 MMB/D capacity of NGL pipelines in service. In 2018, rail moved approximately 113,000 barrels of propane and butane.[56] Trucking and marine are also used for smaller throughput demands. These pipes and rail terminals are used for both transporting Y-grade NGL from the processing plants to the fractionation facilities and purity products from the fractionator to the downstream demand Source: There are no centralized NGL distribution hubs on the West Coast nor long-line NGL pipelines. Most NGL transportation on the West Coast is via rail and truck. Rail and truck are also key to NGL distribution in the eastern United States. Trucking is also used to transport Y-grade NGLs to nearby pipelines for transportation. Marine is generally used to transport purity products such as natural gasoline.

b. NGL Rail

Rail provides great flexibility to ship the product anywhere in the United States. Rail is utilized more during the winter months to meet seasonal loads associated with heating fuel and blending gasoline for winter specifications. Rail does not require batching to move different products. The same train can carry Y-grade, propane, butane, and natural gasoline on different cars, and cars can be transferred to different trains for other destinations. Rail is typically more expensive than pipelines for long distances and large volumes. Due to variations in weather, switching time, delays, etc., rail transit times are more variable than pipelines.

c. NGL Trucking

Trucking offers the greatest flexibility to move small volumes of NGL for short distances. Trucking can provide more predictable scheduling of transportation as there are no batching restrictions or rail scheduling constraints. Trucks are able to act as transportation to connect the processing plants to nearby NGL terminals. Since trucking primarily relies on existing roads and infrastructure, it can be implemented with very short lead times. However, due to low efficiencies and high costs, trucking is not typically a permanent solution for large quantities of NGL transport.

d. NGL Marine

Marine transport can occur along the coasts in a tank vessel or inland via tugboats and barges. Inland NGL marine transport typically utilizes a marine tank barge that requires a tugboat to push the barge for propulsion. Although marine transport is generally more economic than rail or trucking, the obvious limitation to marine transport is that it is limited to major waterways. Shipments that transport goods by water between U.S. ports are subject to the Merchant Marine Act of 1920 (Jones Act). This requires that all goods transported by water between U.S. ports be carried on U.S. flagships, constructed in the United States, owned by U.S. citizens, and crewed by U.S. citizens and U.S. permanent residents. Marine is the most common mode to export NGLs to other nations.

e. NGL Storage

Since the 1940s, hundreds of underground caverns have been used to store NGL as either purity products or mixed NGLs. These caverns, shown in Figure 2-66, are primarily located in salt formations. For seasonal products like propane, storage is of critical importance. At the Mont Belvieu hub, there is more than 240 million barrels

56 U.S. Energy Information Administration, "Movements of Crude Oil and Selected Products by Rail," Petroleum & Other Liquids, https://www.eia.gov/dnav/pet/pet_move_railNA_a_EPLLPA_RAIL_mbbl_a.htm.

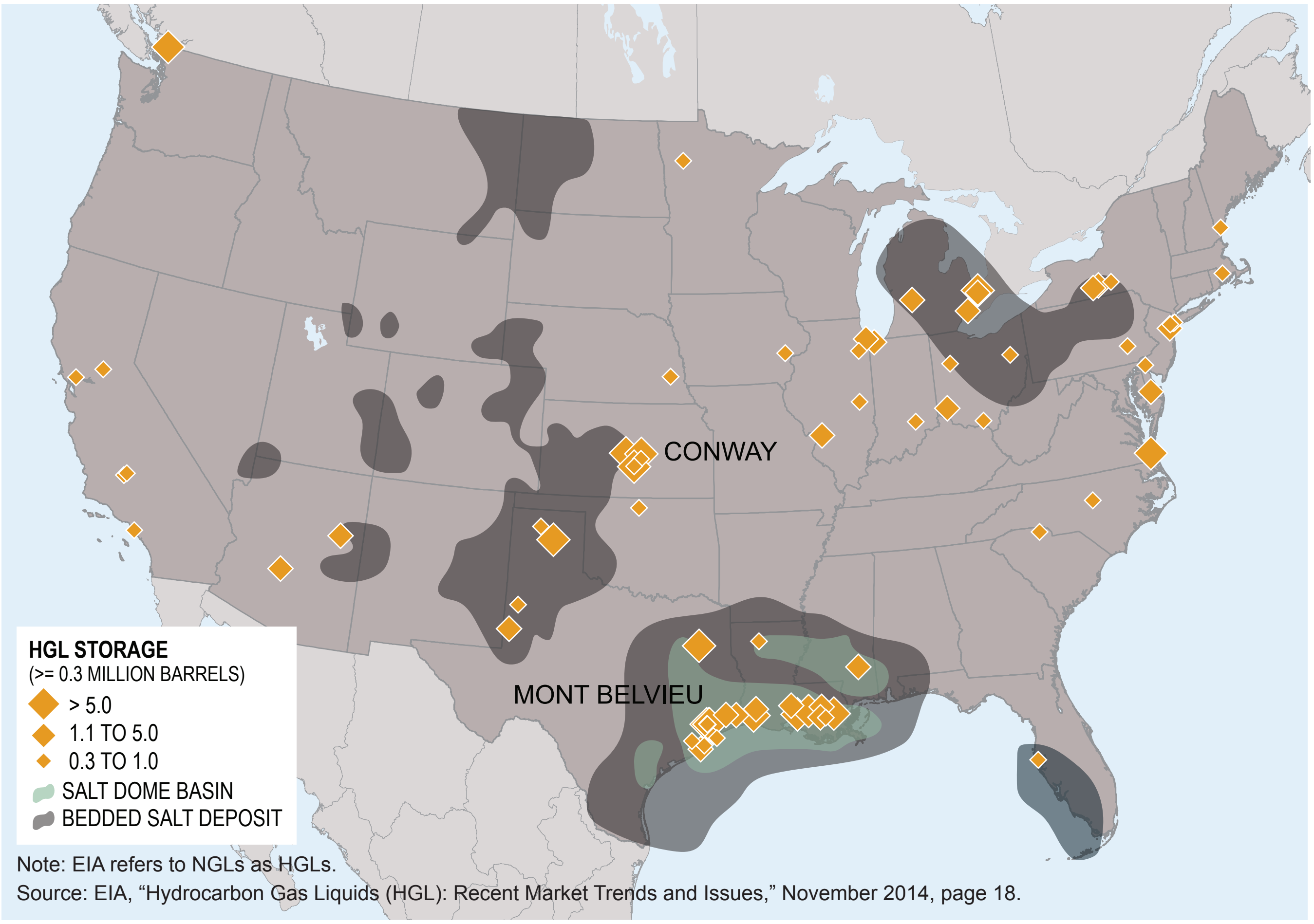


Figure 2-66. *Operating U.S. Underground and Aboveground NGL Storage Facilities*

of NGL storage capacity available.[57] The second largest North American NGL storage hub is located in Conway, Kansas. The East region of the U.S. currently is without an NGL storage hub similar to Mont Belvieu or Conway. In this region, as well as others where no NGL pipelines operate, such as the West Coast, the Rocky Mountains, and Florida, aboveground storage is important to facilitate large movements by rail, tanker, and barge.

In terms of resilience, flooding may impact the salt content of brine ponds that are important to storage. NGL storage depends on the brine, which is injected or removed from the underground sites to control the flow of fuel.

4. History and Current State of NGL Transportation

Prior to the 1980s, a significant portion of Y-grade NGL was fractionated at facilities integrated with natural gas processing plants, but during the 1980s most fractionation was centralized at major NGL fractionation and storage hubs. As previously described, the largest of these hubs is Mont Belvieu, Texas, east of Houston. NGL pipelines from basins in Texas, the Rockies, and the midcontinent moved large volumes of Y-grade NGL to Mont Belvieu for fractionation, storage, and distribution to markets along the Gulf Coast and across the United States. The Conway,

57 NGL storage capacity at Mont Belvieu for Enterprise Product Partners L.P., Targa Resources Corp., OneOK, and Lone Star NGL LLC. Sources: Enterprise Product Partners L.P., "2017 10-K form," February 28, 2018; Targa Resources Corp., "2017 10-K form," February 16, 2018; Energy Transfer Partners L.P., "2017 10-K form," February 23, 2018; and "What's at Mont Belvieu?" *Oil & Gas Journal*, June 2, 2014.

Kansas, hub provides another center of fractionation, storage, and distribution, mostly to markets in the Midwest.

a. Pre-Shale NGL Y-Grade and Purity Product Pipelines

For decades prior to the shale development, the production of NGLs varied little from year to year, averaging about 1.7 MMB/D in the 35 years between 1973 and 2008. U.S. supplies were adequate for most domestic demand, with imports of about 200 MB/D of propane required to supplement production. NGL exports were negligible, averaging less than 100 MB/D, primarily going to Latin America. Figure 2-67 demonstrates the flows of NGL from across the country prior to the shale development.

b. Natural Gas Liquids Pipelines

The major pre-shale NGL pipelines are shown in Figure 2-68. The largest capacity systems moving primarily Y-grade are indicated in black text. These are not the only Y-grade systems, but they accounted for most of the Y-grade volumes transported in the United States before the shale era. Pipelines that moved primarily purity products in the pre-shale era are shown in blue in Figure 2-68. These systems move mostly propane to residential and commercial markets in the Midwest, Southeast, and Northeast.

c. Post-Shale NGL Y-Grade and Purity Product Pipelines

In the early days of the shale development, sufficient NGL pipeline capacity was in place to handle the production growth. But by 2012, capacity constraints had emerged in Texas, the midcontinent, the Rockies, and Appalachia (Marcellus/Utica).

In 2010, U.S. NGL production from natural gas processing started to grow rapidly due to increasing production volumes of wet high-BTU value gas from shale plays containing large quantities of NGLs. Many new gas processing plants were needed to extract the mixed NGLs (Y-grade) from

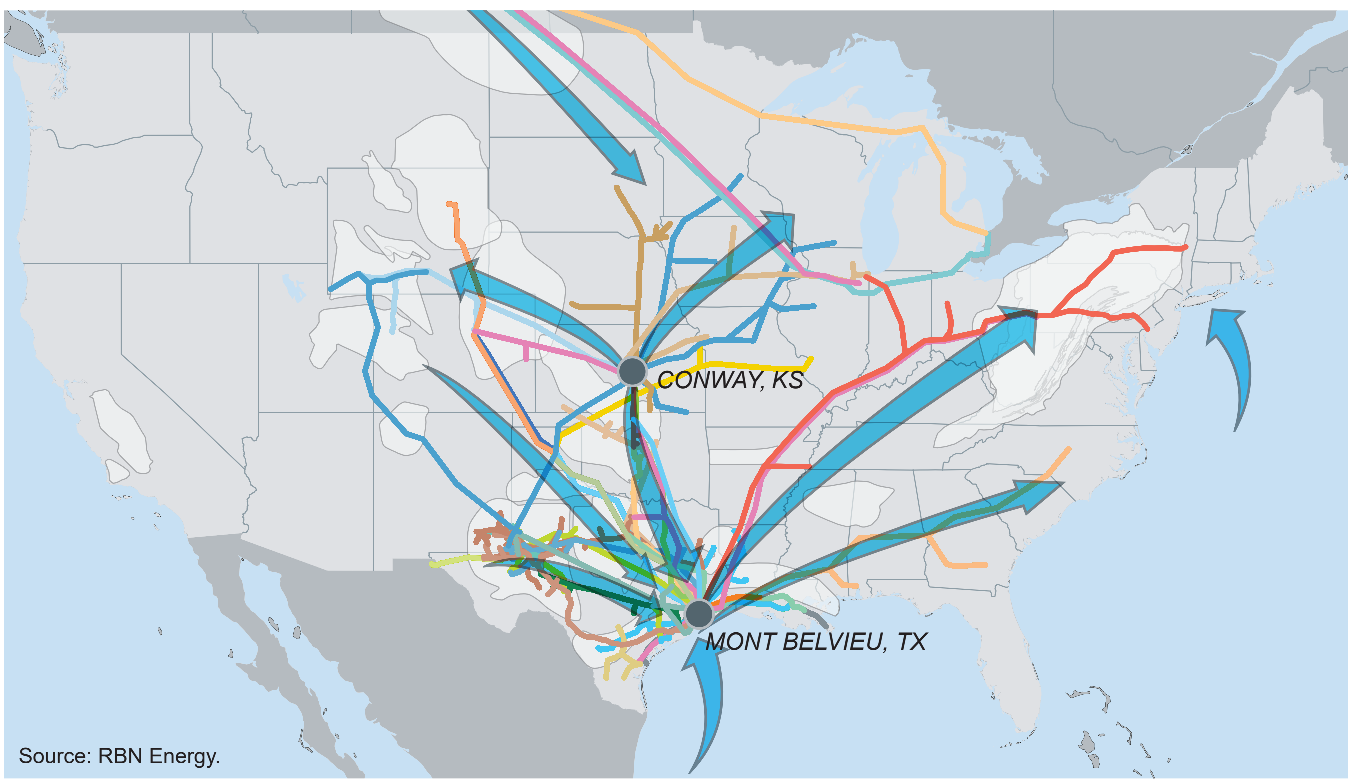


Figure 2-67. *Pre-Shale Revolution NGL Flows*

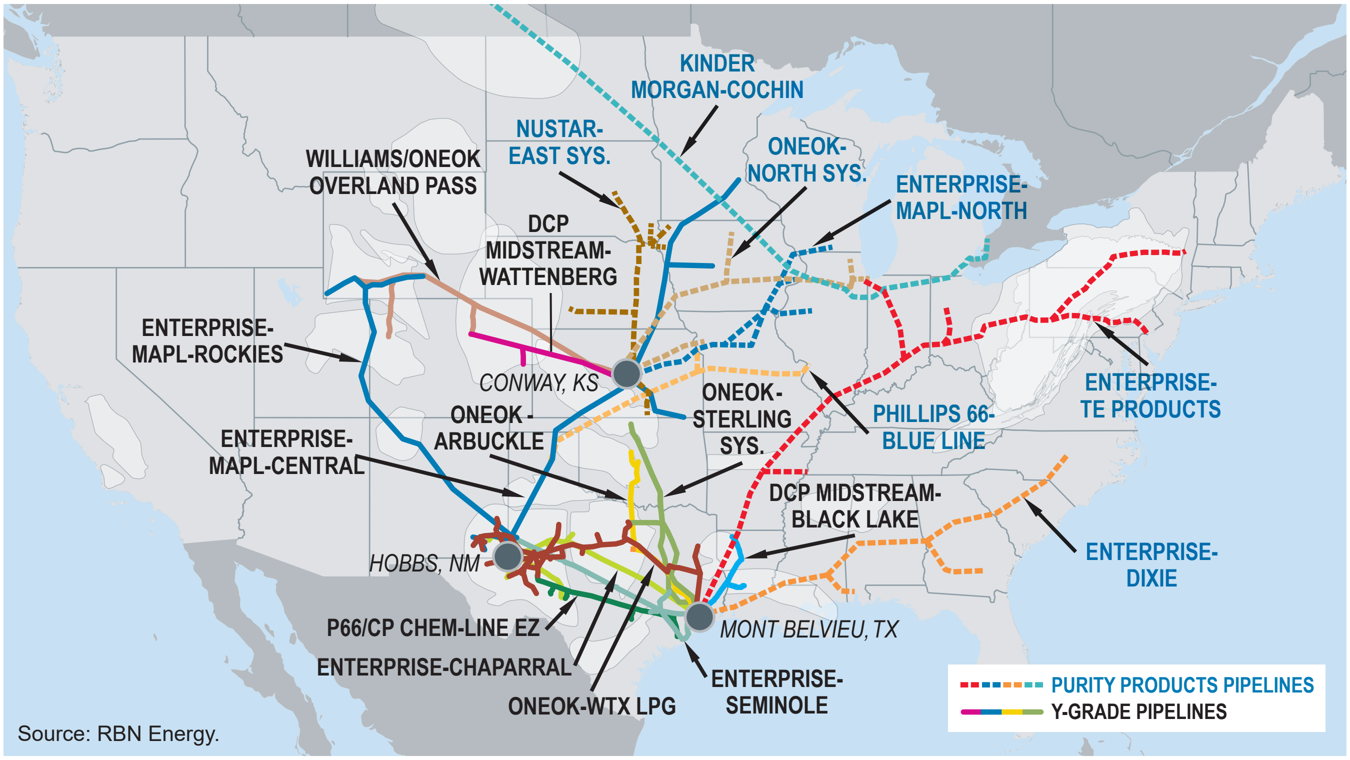


Figure 2-68. *Pre-Shale Y-Grade and Purity Product Pipelines*

the natural gas stream. Production increased from 2.1 MMB/D in 2010 to 4.8 MMB/D in 2018.

Growing volumes of Y-grade production from gas processing plants required the construction of many new pipelines in the 2012 to 2018 time-frame, with volumes moving from shale basins in Texas, the midcontinent, and the Rockies to fractionators in Texas, with Mont Belvieu absorbing most of the barrels.

As more Y-grade volumes flowed to Texas fractionators, those facilities were soon at maximum capacity, prompting the construction of many new fractionation facilities to separate Y-grade into the five purity NGL products—ethane, propane, normal butane, isobutane, and natural gasoline.

d. Y-Grade, 2012 to 2018

From 2012 to 2018, several pipeline projects were developed to move Y-grade to Mont Belvieu. These projects, depicted on Figure 2-69, include Enterprise's MAPL Rockies, which looped (paralleled) its line to add 85 MB/D for delivery into the Permian Basin for ultimate transportation to Mont Belvieu, and expansions by DCP Midstream and Energy Transfer of their existing Sand Hill and Lone Star pipelines. The other projects depicted are primarily greenfield pipelines.

Permian Basin NGL production started to increase in 2012, growing from 340 MB/D in that year to 1,100 MB/D in 2018. To support those growing volumes, several new pipelines were needed, all designed to move Y-grade to Mont Belvieu. These projects are shown on Figure 2-70.

e. Purity Product Pipeline History, 2012 to 2018

During the 2012 to 2018 period, several greenfield pipelines were built to move purity products, primarily ethane, to end-use markets. Three pipelines, Vantage, Utopia, and Mariner West, export products to Canada while

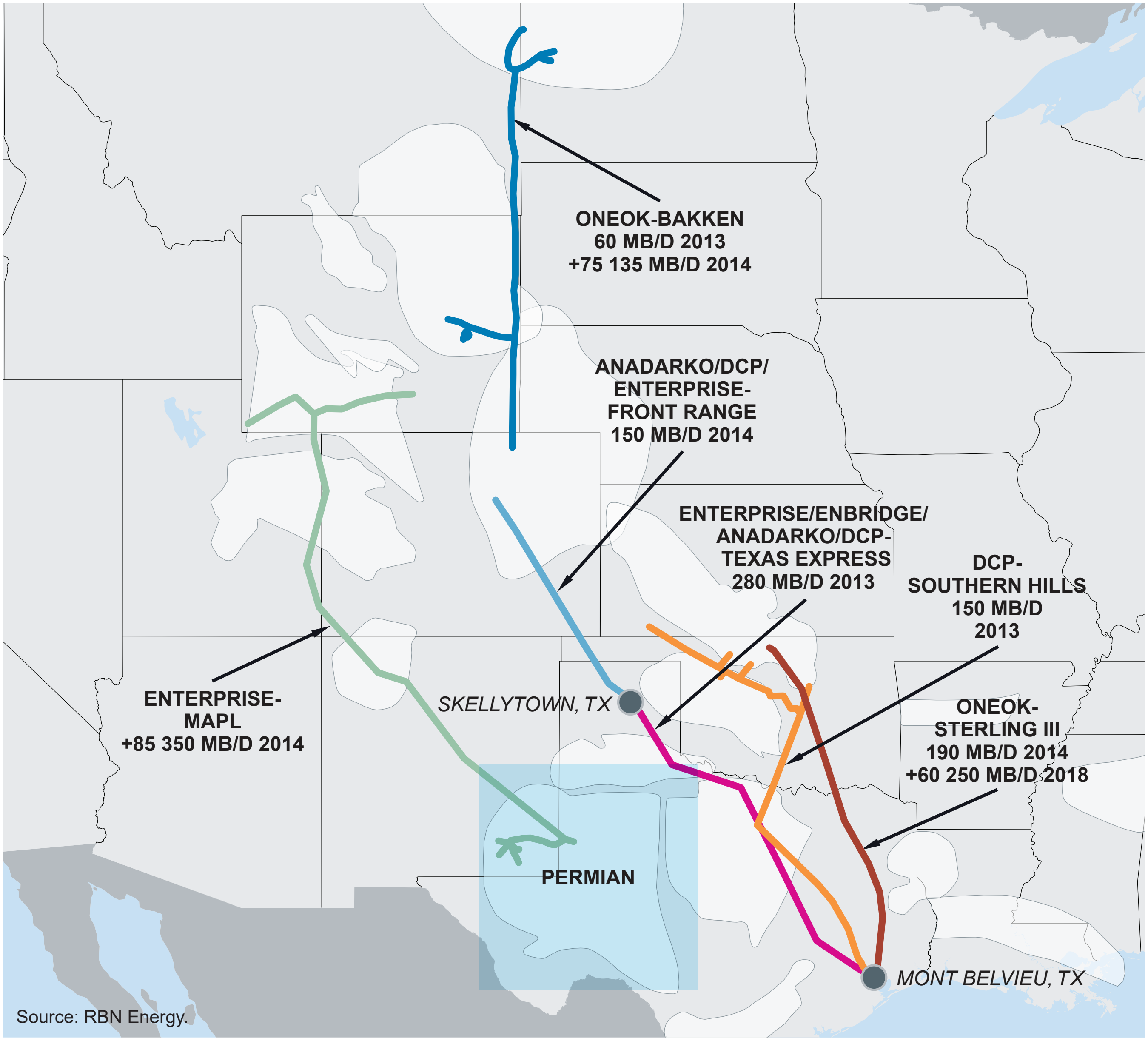


Figure 2-69. *Mixed NGL (Y-Grade) Pipeline History, 2012 to 2018*

Enterprise Appalachia-to-Texas Express moves ethane 1,230 miles from Pennsylvania to Mont Belvieu and Energy Transfer's Mariner East 1 pipeline transports NGLs including ethane to the company's export dock facility at Marcus Hook. These projects are depicted on Figure 2-71 and Figure 2-72.

f. Permian Basin NGL Pipelines, 2019 to 2021

By 2017, much of the focus of NGL market growth had shifted to the Permian Basin as increasing quantities of liquids-rich associated gas were produced along with growing crude oil production volumes. With production growing rapidly, it was becoming apparent that NGL pipeline capacity out of the Permian Basin region would soon be constrained. Over the next 2 years, several new pipeline projects were announced, planned for completion between 2019 and 2021. These projects, directing NGLs to Mount Belvieu, Texas City, and Corpus Christi, included three expansions of existing pipelines and nearly 2 MB/D of new pipeline capacity. These projects are depicted in Figure 2-73.

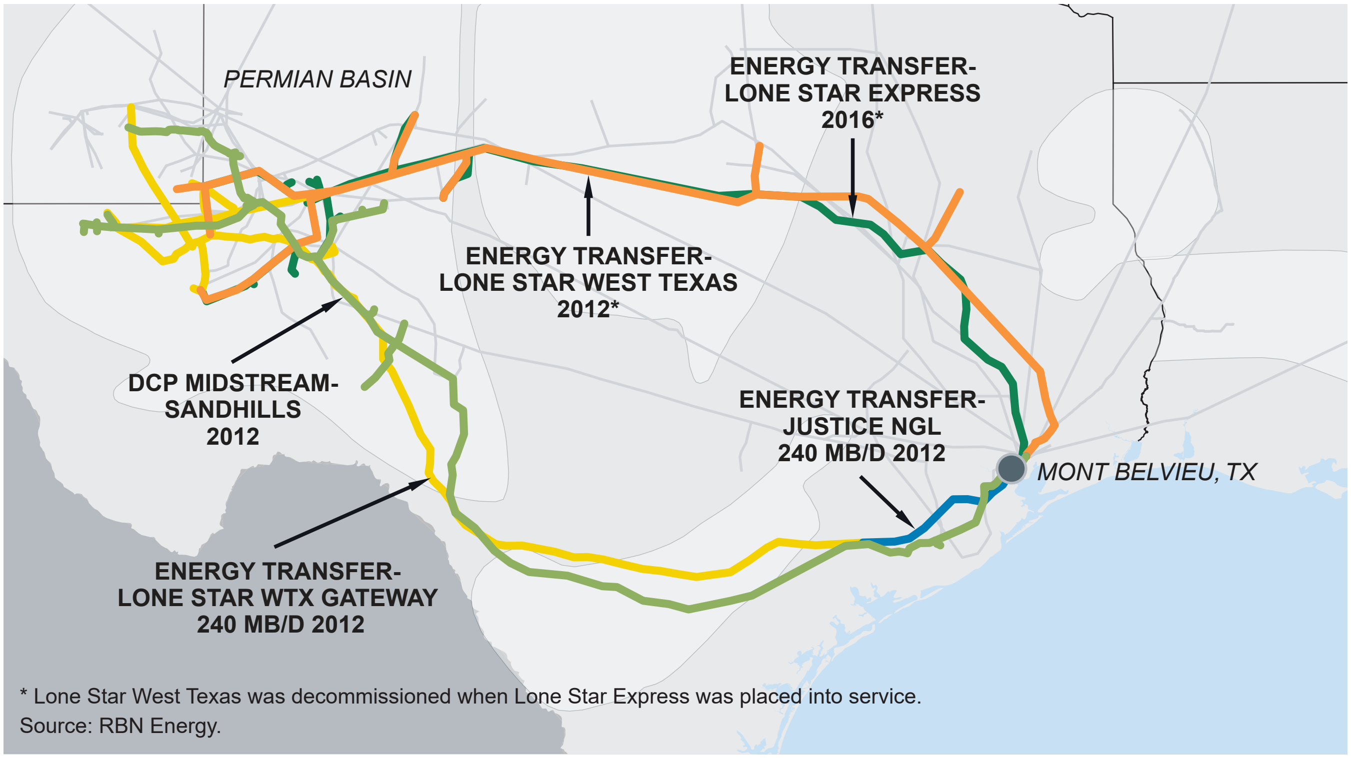


Figure 2-70. *Permian Basin Mixed NGL (Y-Grade) Pipeline History 2012 to 2018*

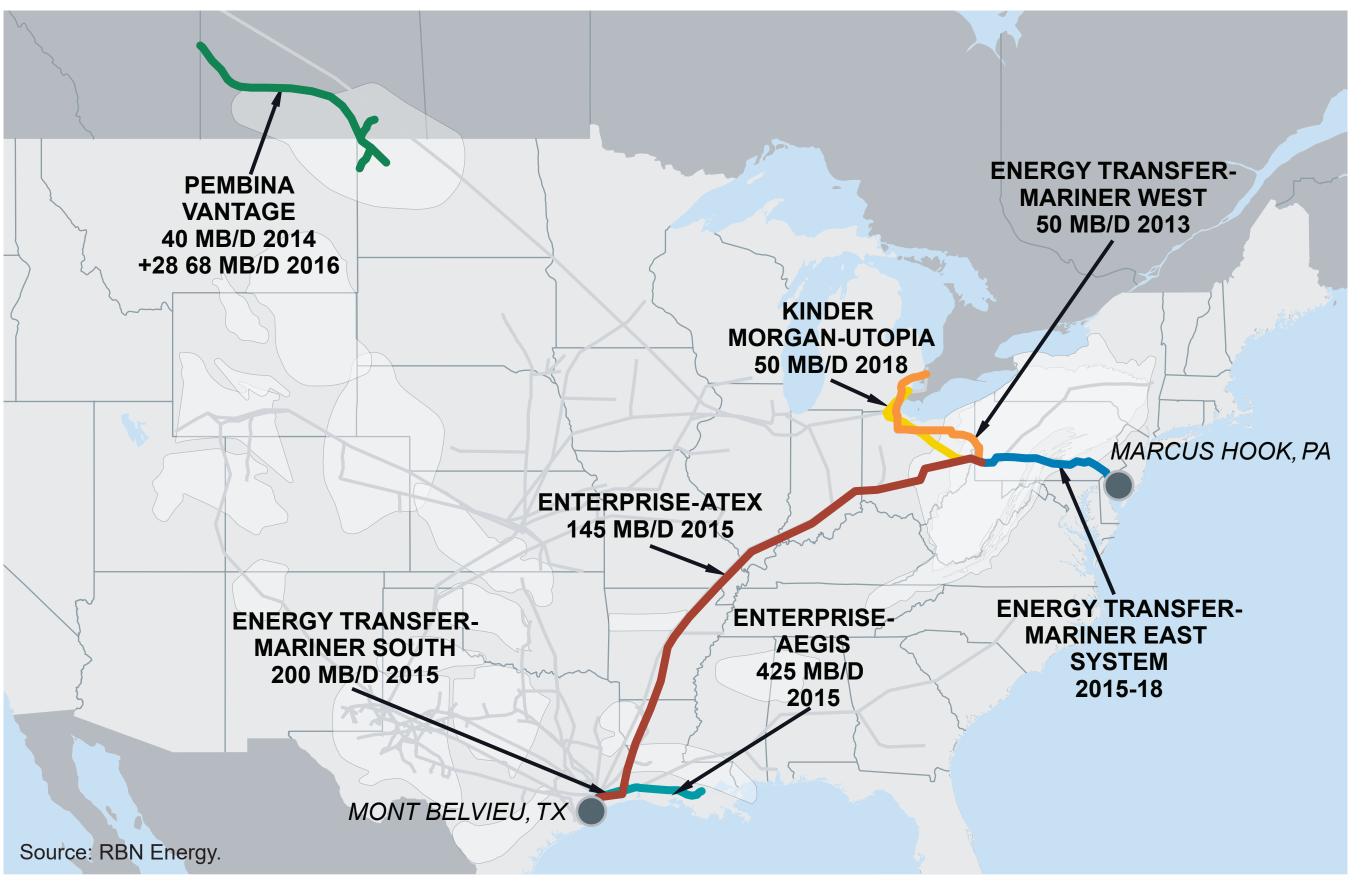


Figure 2-71. *Purity Product Pipeline History, 2012 to 2018*

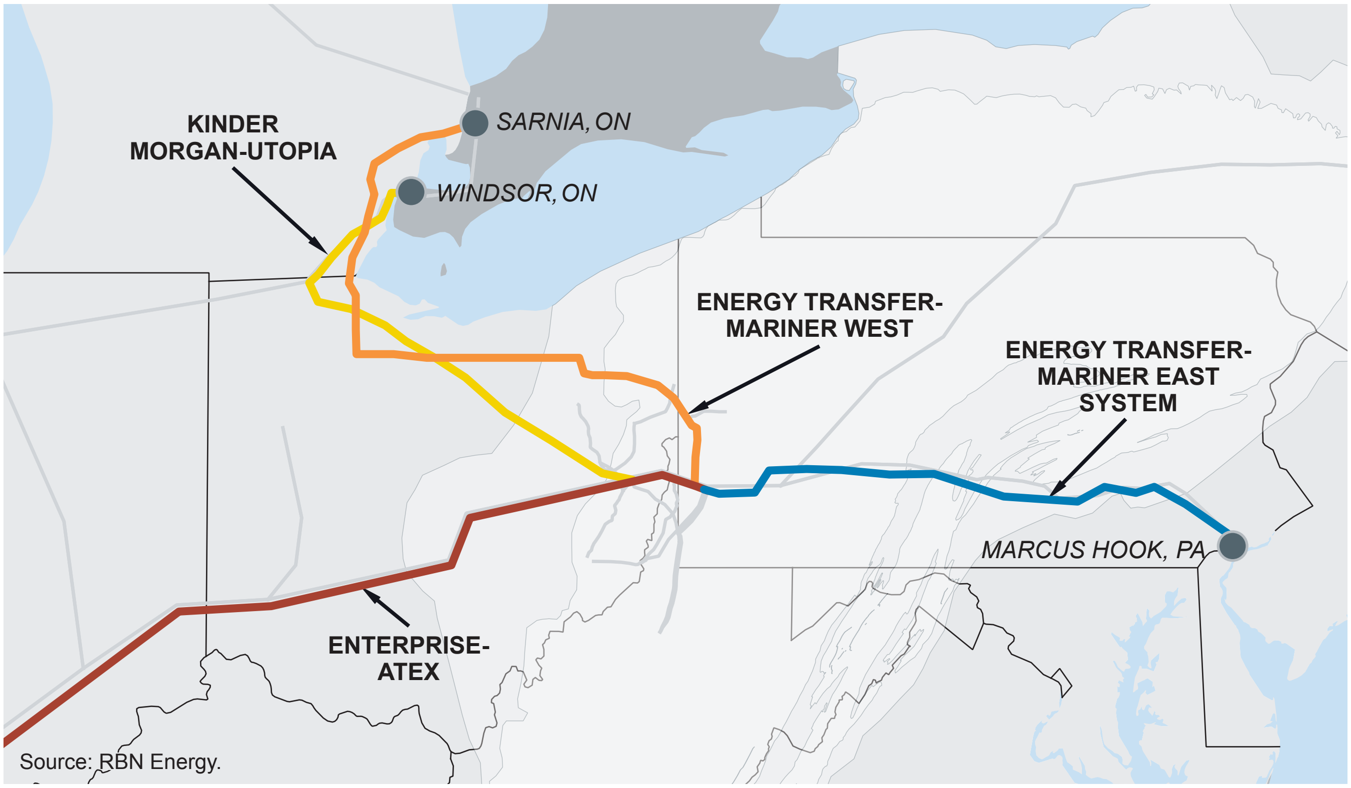


Figure 2-72. Northeast Purity Product Pipeline History, 2012 to 2018

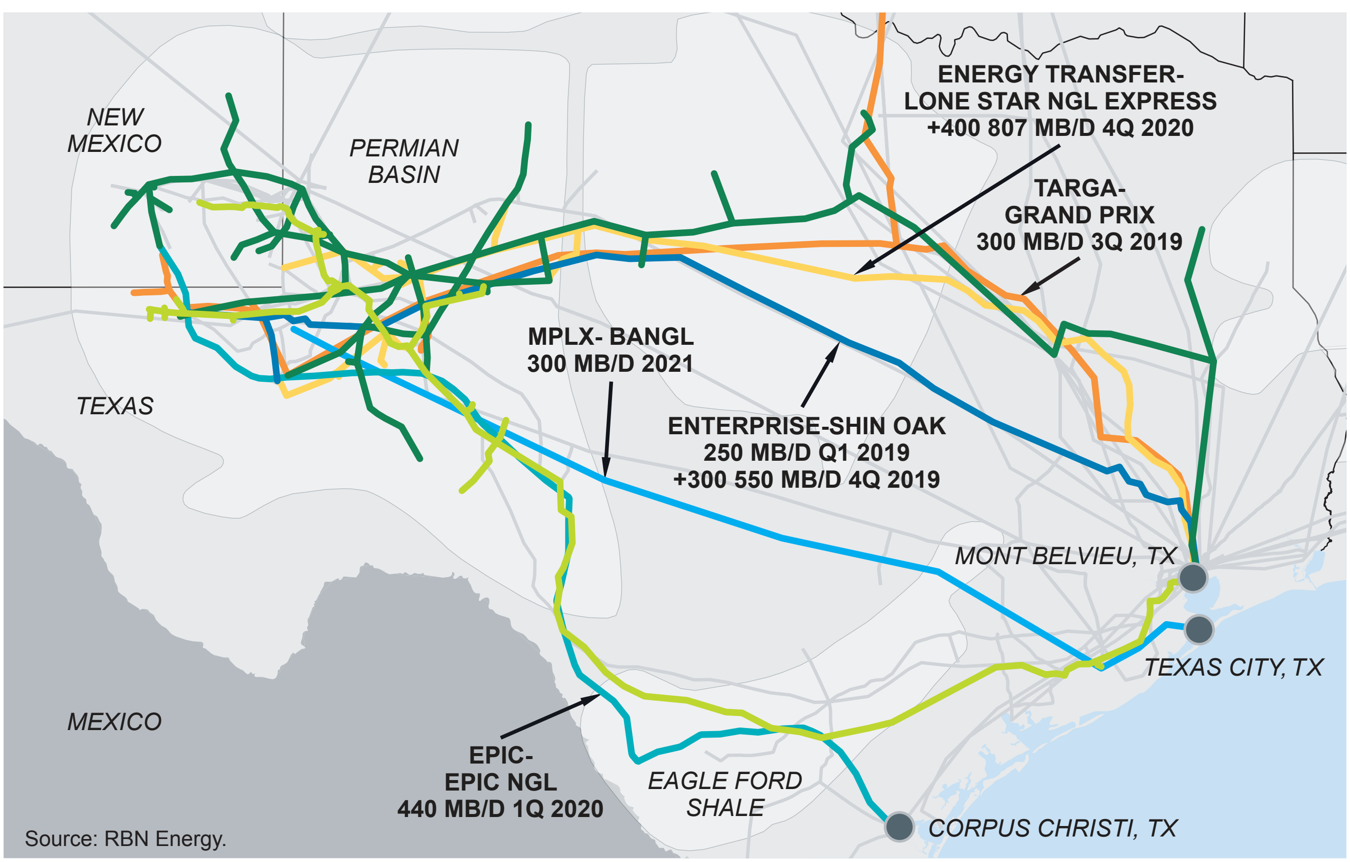


Figure 2-73. Permian Basin NGL Pipelines, 2019-2021

g. *Beyond the Permian Basin, 2019 to 2021*

Similar to the Permian Basin, production growth in the Bakken, Rockies, and SCOOP/STACK has required additional capacity to move Y-grade to fractionation hubs in the midcontinent and Gulf Coast.

Several new pipeline projects have been announced, planned for completion between 2019 and 2021. These projects, depicted in Figure 2-74, are primarily expansions or extensions of existing pipelines.

5. Exports — NGLs

Several NGL export terminals operate in the United States, mostly located along the Gulf Coast. Four Gulf Coast terminals handle about 90% of the liquefied petroleum gases (LPG) (propane and butane) export volumes: Enterprise, Targa, Phillips 66, and Energy Transfer.[58] Other LPG terminals are located along the East Coast (Marcus Hook and Chesapeake Bay), and the West Coast (Ferndale, Washington). Two U.S. terminals have the capability to export ethane—Enterprise Morgan's Point at the inlet of the Houston Ship Channel, and Marcus Hook near Philadelphia (Figure 2-75). In the Northeast, Energy Transfer brought its Mariner East 2 pipeline into full service in 2018 and expects to complete construction on Mariner East 2X, a parallel pipeline to Mariner East 2, in 2019. This will increase capacity to move NGL purity products to the Marcus Hook export terminal.

As NGL production from the Permian Basin, Eagle Ford, and other shale basins has increased, U.S. production of propane has increased far beyond domestic demand. In 2018, 1.7 MMB/D of propane was produced by U.S. gas plants and refineries, while almost 60% or 1.0 MMB/D was exported, primarily from Gulf Coast export docks. LPG exports have rapidly increased, up from less than 0.2 MMB/D in 2011. As depicted in Figure 2-76, LPG export capacity is near fully utilized. This has resulted in low U.S. propane prices. An expansion of the Enterprise export terminal is expected to come online in the second

58 Propane and butane are generally exported off the same dock facilities with many cargos transporting both products.

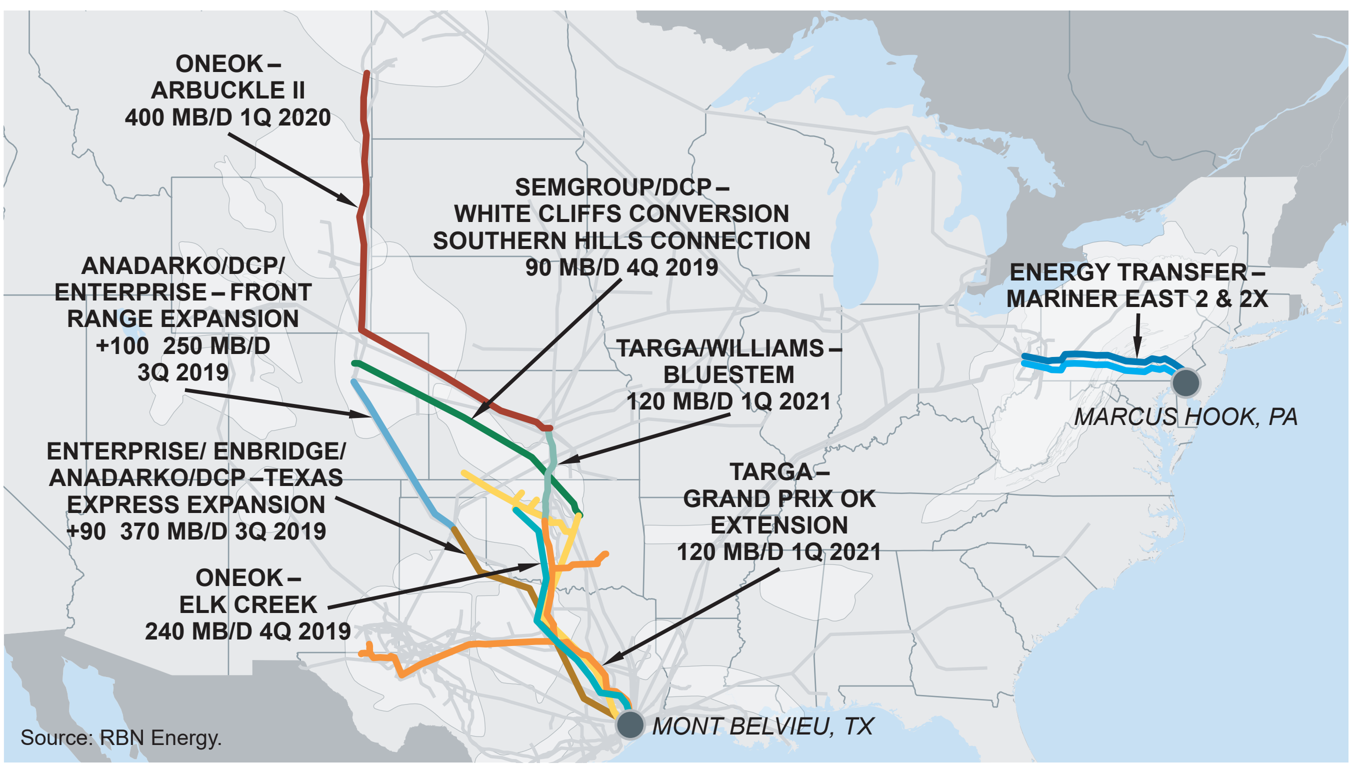


***Figure 2-74.** Y-Grade and Purity Product Pipelines Beyond the Permian Basin, 2019 to 2021*

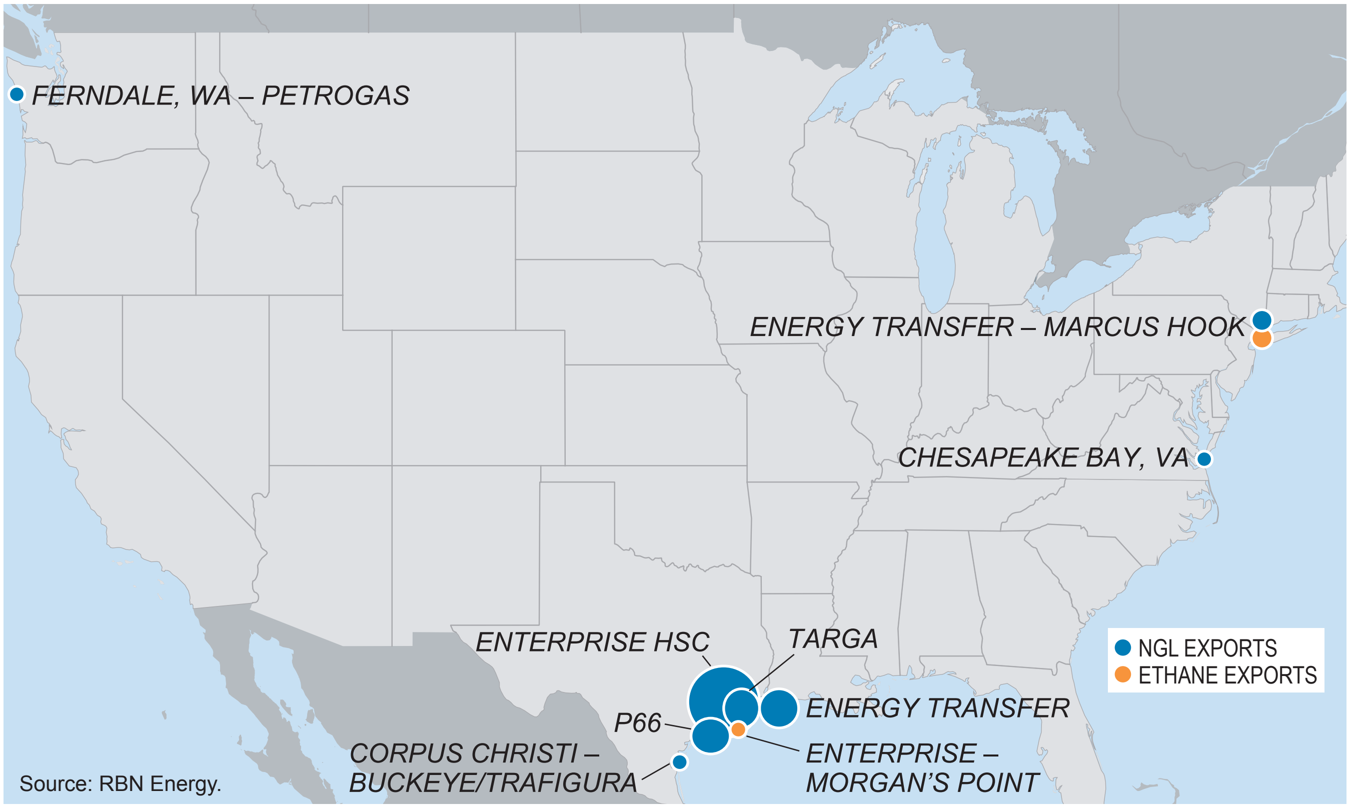
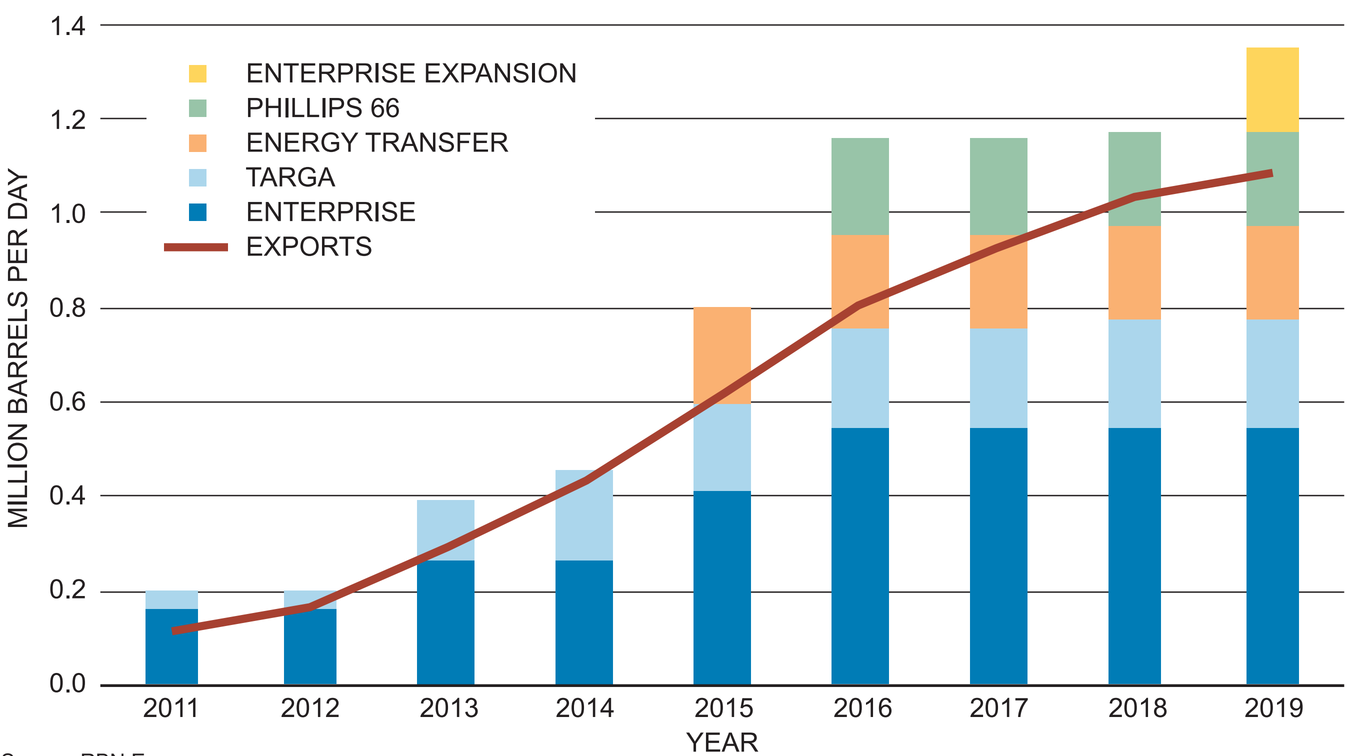


Figure 2-75. NGL and LPG Export Locations



Source: RBN Energy.

Figure 2-76. Gulf Coast LPG Dock Capacity half of 2019, which will relieve the dock capacity constraint for several months, but as NGL production continues to grow, still more capacity will be needed. Energy Transfer has announced an expansion to their Mt. Belvieu facility, and other LPG dock capacity is being discussed for Texas City and Corpus Christi.

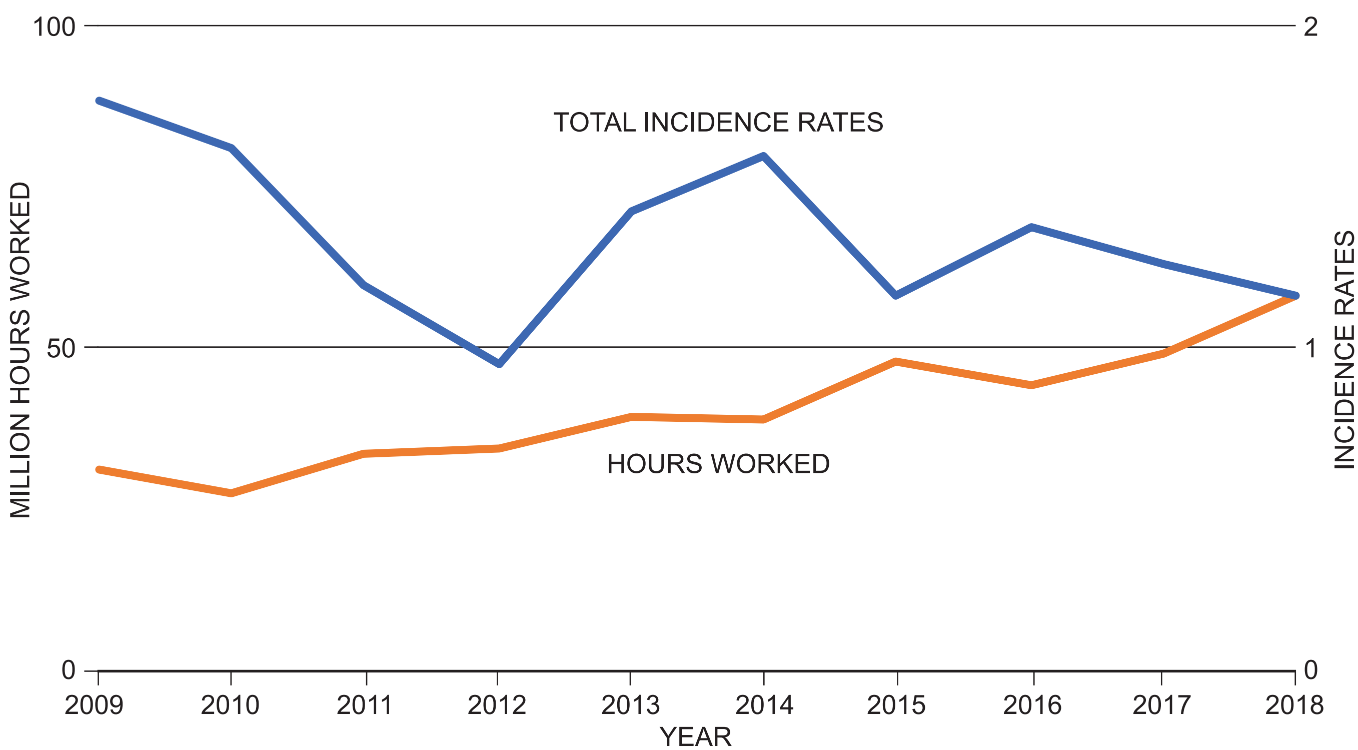
6. Resiliency — NGL Transportation System

Planning and preparation are key to preventing disruptions and recovering from a plant disruption. There are several federal and state organizations that govern and guide plant design and operations. Agencies such as the Occupational Safety and Health Administration and the EPA have developed standards and practices to address several process safety elements, including mechanical integrity of equipment, human actions, and incident investigations to reduce the number of accidents. In addition, all facilities are required to have a response plan in the event of a disruption. Per the safety statistics collected by the GPA Midstream Association, the midstream industry continues to become more resilient against disruptions due to operational error and accidents.[59] See Figure 2-77.

a. Strengths

- There are multiple feedstock connections to processing plants and fractionators, and this interconnectedness provides optionality and therefore resilience.
- The heavy concentration of fractionation plants in the Gulf Coast allows for synergies and efficiencies of operation and access to storage and water.
- The improved safety statistics in the midstream industry shows that it is becoming more resilient against disruptions from operational error and accidents.

59 GPA Midstream Association, Ten Year Historical Summary of GPA Midstream Operational Employees Safety Statistics 2008-2017.



Source. GPA Midstream Association.

Figure 2-77. Midstream Safety Statistics, 2009-2018

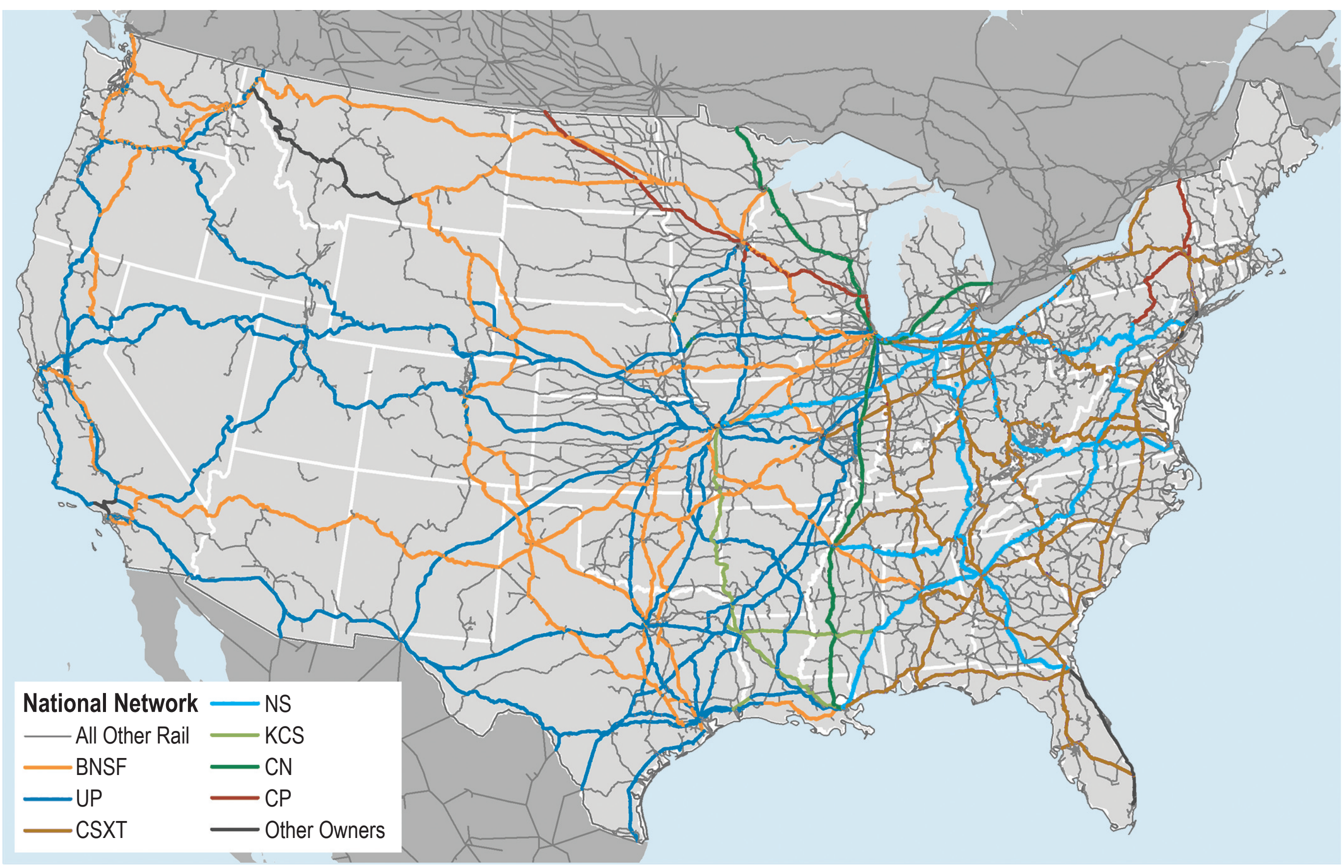
- There are numerous fractionators and processing plants and as such, disruption to any facility would not have a significant impact to overall regional production.

b. Exposures

- Both processing plants and fractionators are aboveground and are vulnerable to weather or seismic events.
- Fractionation operations are particularly vulnerable to flooding from a storm on the Gulf Coast. Due to the significant capacity in the area, and interdependency between NGL, crude oil, and natural gas, disruptions can impact oil and natural gas production in other regions.
- Processing plant operations are vulnerable to winter storms. In the event of a disruption, oil and natural gas production can be impacted, and in areas like the Northeast where there is little spare processing capacity, impacts can be significant.

Findings:

- Fractionation operations are particularly vulnerable to flooding from a storm on the Gulf Coast. Due to the significant capacity in the area, and interdependency between NGL, crude oil, and natural gas, disruptions can impact oil and natural gas production in other regions.
- Processing plant operations are vulnerable to winter storms. In the event of a disruption, oil and natural gas production can be impacted, and in areas like the Northeast where there is little spare processing capacity, impacts can be significant.



Source: Association of American Railroads, *National Rail Freight Infrastructure Capacity and Investment Study*, prepared by Cambridge Systematics, Inc., Cambridge, MA, September 2007, page 4-1.

Figure 2-78. *National Rail Freight Network and Primary Rail Freight Corridors*

F. Mobile Transport

1. Rail Transportation System

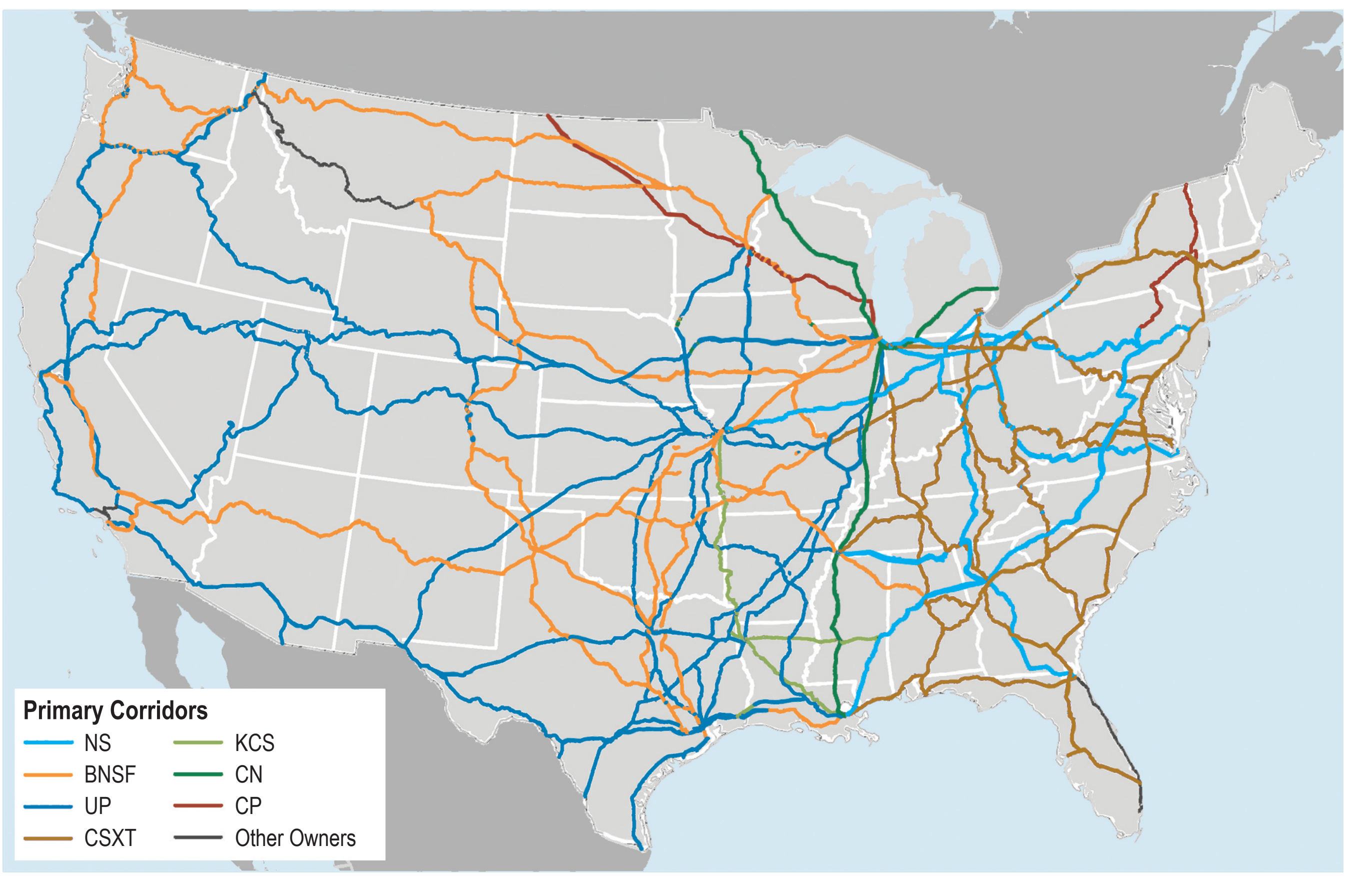
The North American rail system is a privately owned network of railroads providing highly robust transportation within all 49 mainland states, with basic infrastructure developed over more than 100 years and updated continuously as necessary to meet customer needs, safety developments, and technology opportunities. The U.S. rail freight network includes 136,898 miles in the contiguous U.S. states and Alaska.[60] For regulatory purposes, this network is divided into Class I, II, and III railroads (Figure 2-78). Class I includes the largest seven U.S. railroads: BNSF Railway, Canadian National (Grand Trunk Corporation), Canadian Pacific (Soo Line), CSX Transportation, Kansas City Southern, Norfolk Southern, and Union Pacific. Class I railroads have collectively been formed by mergers and acquisition of hundreds of smaller railroads. Smaller Class II/III railroads include more than 550 short-line and regional freight railroads. Class II/III railroads include many legacy railroads as well as line segments divested by Class I railroads.[61]

Of the 136,898 miles in the U.S. rail freight network, the highest-volume corridors designated by Class I railroads total about 52,340 miles of road (or centerline miles), representing about half of all Class I-operated miles in the United States and about one-third of the 140,810 miles in the U.S. rail freight network (Figure 2-79).[62]

60 Association of American Railroads, "Rail Fast Facts For 2017," https://www.aar.org/wp-content/uploads/2019/01/AAR-United-States-Fact-Sheet.pdf (accessed October 1, 2019).

61 Association of American Railroads, *National Rail Freight Infrastructure Capacity and Investment Study*, prepared by Cambridge Systematics, Inc., Cambridge, MA, September 2007, various pages.

62 Association of American Railroads, *National Rail Freight Infrastructure Capacity and Investment Study,* prepared by Cambridge Systematics, Inc., Cambridge, MA, September 2007, p. 4-1.



Source: Association of American Railroads, *National Rail Freight Infrastructure Capacity and Investment Study*, prepared by Cambridge Systematics, Inc., Cambridge, MA, September 2007, page 4-2.

Figure 2-79. *Primary Rail Freight Corridors*

The capacity of rail corridors is determined by many factors, including the number of tracks, the frequency and length of sidings, the capacity of the yards and terminals along a corridor to receive the traffic, the type of control systems, the terrain, the mix of train types, the power of the locomotives, track speed, and individual railroad operating practices. The three dominant factors determining capacity are the number of tracks, type of signal system, and mix of train types.[63]

The U.S. rail freight network is highly efficient by world standards. A single standard track gauge simplifies locomotive and railcar interchange between railroads. Management processes simplify interchange between railroads, including the use of standardized locomotives, railcars, and other equipment, and standardized signaling. Run-through trains often provide interchange from one railroad to another of entire trains, with one railroad's train crew stepping off the train and another railroad's train crew stepping onto the train to minimize infrastructure and locomotive needs, as well as work events and cycle time.

Characteristics of the U.S. rail system include:

- Railroads own, develop, maintain, and pay taxes on their infrastructure.
- Shared network allows passengers, where the passenger or commuter agency has an agreement with the host freight railroad and various freight commodities, to share the investment and maintenance associated with track, signal systems, and other infrastructure. Sharing may provide resilience across business and commodity cycles, mitigating some capacity investment risk in high-volume corridors. Sharing also risks capacity limitations if multiple commodities demand capacity on that corridor at the same time.
- Extensive existing U.S. rail infrastructure enables most production basins and destinations to be connected by rail at relatively low investment cost via truck or pipeline multimodal transload facility. Rail can generally move any commodity from anywhere to anywhere in the contiguous U.S. directly or with short last mile truck or pipeline connectivity.
- Highly scalable, incremental capacity can be added to the existing network to meet incremental volumes due to market growth and or new development opportunities.
- Line capacity can usually be added relatively quickly in existing right-of-way; however, regulatory, permitting and roadbed grading processes can make rail line build outside of existing right-of-way an expensive multiyear endeavor.

Finding: The breadth of rail infrastructure, combined with rail's ability to add capacity in relatively small increments, provides shippers with the ability to quickly and efficiently access a broad network of potential origins and destinations.

The NPC recommends maintaining a rail regulatory infrastructure that facilitates continued private investment in a robust North American rail system.

From a rail capacity standpoint, the U.S. rail system is generally a one-lane road requiring train-sized sidings to enable one train to pass by (meet) or overtake (pass) another train. Double-track provides two separate lanes, easing meet/pass situations and, in busy corridors, even more tracks may be in service. Sophisticated signal systems and centralized, automatically actuated switches can also add capacity. Capacity is reduced by the need to perform periodic scheduled and unscheduled maintenance, commuter operations in some corridors, and by different types of trains moving at various train speeds. Capacity can be added through investment in line, terminal or other physical infrastructure, signal systems, locomotives, personnel, and management processes.

Rail movements generally move in one of three types of service: single-car, multicar block, or unit train. Single-car movements are often most efficient for relatively small volumes due to limited

63 Association of American Railroads, *National Rail Freight Infrastructure Capacity and Investment Study,* prepared by Cambridge Systematics, Inc., Cambridge, MA, September 2007, p. 4-5.

investment requirements for terminal facilities. Multicar blocks allow greater volumes and generally move in the same mixed-commodity manifest train network that typically involves significant railroad handling from origin facility to origin terminal, terminal-to-terminal-to-terminal in mixed trains, and from final terminal to destination facility. A unit train is a trainload of product generally moving from one origin to one destination without handling at intermediate terminals. Unit trains can typically provide substantial reduction in round-trip cycle time and are appropriate for high-volume origin-destination lanes.

Rail tank cars are generally owned by shippers rather than railroads. Modern liquids tank cars have maximum gross weight of 286,000 pounds (143 tons), whereas NGL/LPG pressure cars have maximum gross weight of 268,000 pounds (134 tons). Tank car capacity is dependent on commodity characteristics with a melting point above ambient temperature and require use of a coiled/insulated car, whereas commodities with lower melting points can use a general-purpose tank car without heating coils. Because heavier petroleum products tend to have higher melting points, and tank cars are built to optimize tank volume to weight, a coiled/insulated car will generally be built with less capacity than a general-purpose car.

The NPC recommends continuing to facilitate transition to DOT-117J/DOT-120J Next Generation tank cars for movement of flammable nonpressurized commodities.

Rail capacity availability and timeline from demand to movement is highly dependent on the origin, destination, and commodity to be moved. For example, procurement of railcars to meet a project's needs may require building new railcars. Depending on manufacturer backlog, railcar build timelines could range from months to years. Terminal capacity may be readily available if an existing terminal can be used as is or repurposed. Otherwise, permitting and building may require a longer timeline. Railroads may have enough line, locomotive and personnel capacity, or they may need to add such capacity subject to timelines for permitting, building, manufacturing, and/or personnel hiring and training. Petroleum products represent approximately 5% of total rail shipments, evidence that robust capacity exists. Its greatest constraint may be tank car supplies. Tank car availability can be a short-term constraint but market signals typically resolve those capacity issues quickly.

Finding: In rail corridors with constrained line and terminal capacity, timely permitting is critical to enabling rail to respond to shipper needs.

The NPC recommends providing a regulatory framework enabling timely permitting of rail-related projects on existing right-of-way, which is critical to enabling rail to respond to shipper needs.

The DOT Surface Transportation Board regulates shipper and railroad economics, service, environmental, and competition. DOT's Federal Railroad Administration regulates most elements of railroad safety.

The system provides shippers a range of options for efficient movement of crude oil, NGL, and refined products from less-than-daily single-car shipments of approximately 600 barrels to accommodate small origin-destination market needs to multiple daily unit trains of approximately 60,000 barrels each to accommodate larger markets. Rails are a safe transportation option: in 2017, more than 99.99% of rail hazardous material (hazmat) shipments reached their destinations without a release caused by a train accident.

Rail transportation is a robust transportation model for large and small volumes of petroleum liquids, including crude oil, NGL, LPG, and refined products. Rail's quick reaction to increased North Dakota crude oil production enabled more than 500,000 barrels per day of otherwise stranded oil to be received at destination markets during 2014, increasing North Dakota's economic prosperity while reducing U.S. and Canadian refiner crude oil input costs.

While railroads are typically capable of responding quickly to market signals, this supply chain may be constrained by a few physical or economic factors. When Permian Basin production exceeded pipeline capacity in 2018, rail infrastructure was sufficient to move much of the increment. However, the projected 1 to 2-year timeline until pipelines would be available caused some potential rail shippers to avoid taking on multiyear railcar, terminal, and rail transportation commitments in favor of temporarily reducing production volumes until pipeline capacity became available.

2. Resiliency — Rail

Across the North American rail system, multiple factors have led to a robust and resilient transportation structure, including:

- Standard rail gauge, locomotives and railcars
- Standard signal systems, further standardized through positive train control
- Similar operating procedures and rules
- Similar management and labor union structures.

Historical merger and acquisition activity has led to consolidation into seven large Class I railroads and hundreds of smaller Class II/III railroads. This historical consolidation provides strong resiliency within the North American rail system by simplifying communication and operations; providing the four largest Class I systems with robust internal resiliency; planned interoperability among the seven Class I railroads via numerous gateways; and its use of tactical re-route protocols with other railroads to address off-schedule operations.

A relatively small set of large Class I railroads simplifies communication and operation across primary rail corridors, since many petroleum products shipments can be handled within one railroad's network or within a small number of cooperating railroads.

The four largest Class I railroads generally have robust internal resiliency, typically with multiple routes from given origins and destinations. Baseline rail routings will normally be the most direct, lowest-cost routing; and these routings will generally also be the fastest routes. Consequently, rerouting shipments to avoid service interruptions may involve an increase in origin-destination miles and cycle time, which, in the absence of additional railcar assets, may temporarily reduce total available capacity. To enable rail customer shipments between any origin-destination lanes, the seven Class I railroads have a long history of interchanging customer shipments across numerous gateways. Interchange protocols are well-established and frequently used.

In addition to planned interchanges between various railroads, the Class I railroads also have established protocols for off-schedule operations. Use of these tactical and operationally coordinated re-route protocols provides an additional level of ad-hoc resiliency between railroads.

3. Marine and Waterways Transportation System

The marine transportation network consists of both public and private infrastructure. One of the few enumerated powers of the federal government under the U.S. Constitution is the regulation of commerce between the states and with foreign countries, hence the federal role in the facilitation and regulation of maritime commerce, which has been pervasive since the earliest days of our country. The federal government, acting through the U.S. Army Corps of Engineers, builds and maintains coastal and inland navigation channels, locks, dams, and river control structures. Within the United States, there are currently 14 deep-draft ports designated as energy transfer ports under criteria set out in the Water Resources Development Act of 2016 (WRDA 2016).[64]

There are important energy transfer ports that do not fall within the statutory definition in the Water Resources Development Act of 2016, including the ports on the Delaware River, Freeport in Texas, and others. Other ports are sites of significant planned energy transfer activities, including Brownsville, Texas. Many energy ports handle cargoes in addition to energy cargoes, including containerized goods, steel, grain, and bulk cargoes. One feature of the designation of a port as an

64 The 14 Energy Transfer Ports are in Mobile, AL; Long Beach, CA; Baton Rouge, LA; Lake Charles, LA; New Orleans, LA; Plaquemines, LA; South Louisiana, LA; Baltimore, MD; New York/New Jersey, NY & NJ; Beaumont, TX; Corpus Christi, TX; Houston, TX; Texas City, TX; Norfolk, VA.

Energy Transfer Port is availability of extra maintenance funding. Currently, the government collects a tax on imported cargoes to fund a Harbor Maintenance Trust Fund. Funds are received each year to maintain all coastal ports at their authorized dimensions, but appropriations from the fund are insufficient to maintain even the most critical energy ports at their authorized dimensions.

The inland waterway system (Figure 2-80) is a major artery for energy transportation in the nation. It consists of some 12,000 miles of commercially navigable channels and some 240 lock sites that facilitate commerce to and from 38 states.[65] For calendar year 2017, the inland waterways handled 152 million tons of petroleum and petroleum products.[66] This represents about 28% of the 536 million overall tons moved on the system.

65 Waterways Council, Inc., "Waterways System," https://www.waterwayscouncil.org/waterways-system (accessed September 1, 2019).

66 U.S. Army Corps of Engineers, *The U.S. Waterway System, 2017 Transportation Facts & Information*, Institute for Water Resources Library, October 2017.

While the federal government builds and maintains the ports, harbors, and waterways, private capital supplies the vessels operating on them, as well as the loading and unloading facilities. Historically, many major oil companies operated their own marine fleets to distribute their products. Today, it is more common for independent operators to provide marine transportation services. These range from large public and private companies to small family businesses. The terminals that provide the interface between marine transportation and other modes for petroleum cargoes are mostly privately owned and operated, but there are some petroleum terminal facilities operated by state and local government entities and port authorities.

Petroleum bound for destinations in the international marketplace can travel on a vessel of any nationality. Cargoes traveling between two points within the United States must be U.S. built, owned, flagged, and crewed. Petroleum cargoes are most often transported in bulk in tank vessels. The domestic U.S. fleet of tank vessels has more

Source: U.S. Army Corps of Engineers, Institute for Water Resources.

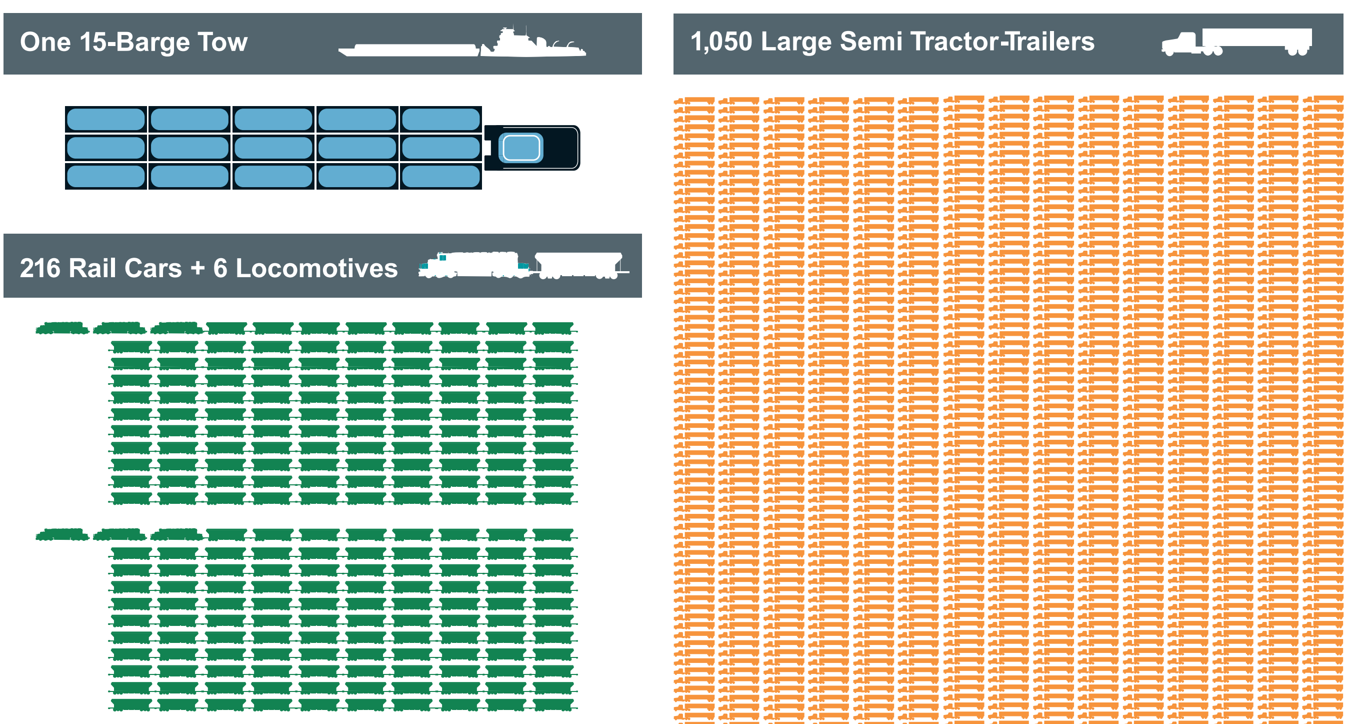
Figure 2-80. *Map of U.S. Inland Waterways* than 4,000 vessels, mostly inland barges, but also includes coastal and ocean barges and tank ships. The domestic fleet for the transport of LPG numbers more than 100 vessels. Although many are capable of carriage of propane or other NGLs, this fleet is most commonly used to transport petrochemicals used as feedstocks for the chemical and plastic industries, such as butadiene or propylene oxide. Until recently, there has not been a market for the domestic transportation of LNG, and U.S. yards had not built LNG carriers in a few years, but with the advent of the use of LNG as a ship's fuel, one LNG vessel designed for bunker service has been delivered in the past year and two more are under construction today.

Within the domestic coastal fleet, the most predominant of the self-propelled tank ships are medium-range tankers with a capacity of approximately 330,000 barrels. Some larger ships are in crude oil service, especially serving the Alaska market. Most of the tank vessel fleet consists of barges. The largest articulated tug-barge units rival the medium-range tankers in capacity and are certified for ocean service. The smallest coastal barges have a capacity of less than 50,000 barrels each. There are approximately 300 tank barges in coastal service with a combined capacity of approximately 25 million barrels.

There are almost 4,000 tank barges in the inland fleet, generally of two sizes, 300' by 54' barges with a capacity of approximately 27,500 barrels and 200' by 35' barges with a capacity of approximately 10,000 barrels. Depending on the waterway segment being traversed and customer requirements, a single inland towboat can push anywhere from one to 15 or more barges. As depicted in Figure 2-81, 15 barges of 10,000-barrel capacity each, being towed by a single boat, is a common tow size on the locking rivers of the Midwest and is equivalent to two-unit trains totaling 216 rail cars or 1,050 large semi-tractor-trailer combinations.[67]

The tank vessel industry is regulated by the U.S. Coast Guard. These regulations deal with construction and maintenance standards—crew numbers, qualifications, and licensing, operational

67 Howell Creative Group for the National Waterways Foundation.



Source: Howell Creative Group for the National Waterways Foundation.

Figure 2-81. *Equivalent Carrying Capacity among Barges, Trains, and Trucks* procedures, environmental performance, emergency planning and response, and more. Many forms of state and local regulation are considered preempted by federal law, but there are certain areas where the states have been permitted to supplement federal law with their own requirements, particularly with respect to environmental matters. Whereas non-U.S. flag vessels in international commerce to or from the United States are subject to some U.S. laws and regulations, all vessels in domestic commerce are subject to the full range of U.S. laws applicable to other domestic businesses, including income and *ad valorem* taxes, wage and hour requirements, employee tax withholding, and the like.

As in the other modes, safety is paramount in the marine transportation industry. Safety management systems, careful vetting by shippers and safety culture commitments, all with government oversight, have significantly reduced spills and other incidents over the last 30 years.

In general, the marine transportation system is not viewed as being capacity constrained in terms of the ability of ports and waterways to handle additional vessel traffic, although there can be localized congestion, which can be exacerbated by poor weather conditions and operational upsets. Throughput capacity of coastal ports can vary with the depth of their channels. Many of the larger tankers used for international voyages are capable of loading to drafts to the maximum project depths of the U.S. ports in which they operate. To fully load outbound cargoes, or to unload inbound cargoes with drafts exceeding channel capacity, these vessels require offshore lightering.

While on a national scale our port system can be viewed as having adequate capacity, the energy boom has had some significant impacts on a few key energy ports. The Port of Houston is home to the largest petrochemical and refining complex in the United States. Its proximity to the NGL infrastructure in Mont Belvieu, Texas, makes the Port of Houston the largest exporter of NGLs in the United States. The port is also a significant container port and receives steel and other bulk cargoes. Congestion has become a significant issue in the port. Various efforts are underway to address this. The Texas legislature has addressed the issue, which arose when the channel was restricted to one-way traffic to accommodate the entry and departure of certain large containerships. One-way traffic to accommodate a single ship has the impact of restricting the movement of other ships for hours and thus decreases the throughput capacity of the port as a whole. By impacting the arrival and departure times of ships carrying energy cargoes, this impact extends to the terminals on which these ships call, ultimately limiting the throughput capacity of energy cargoes. Work is ongoing to look for ways to safely accommodate oversize ships without restricting movement of other vessels, but the ultimate solution is to widen the channel.

The U.S. Army Corps of Engineers is currently studying alternatives to widen the Houston Ship Channel, in consultation with the Port of Houston Authority. Many stakeholders, including energy transportation interests, are advocating for improvements to the channel that will widen it where larger ships call and congestion exists to accommodate the larger ships and improve safety and efficiency for all ships. However, the current Corps proposal is to widen only the section of the channel in the southern half of Galveston Bay and not extend the wider channel to the berths where the larger ships are calling and to the area where numerous collisions and oil spills have occurred. Shifting cargo to other ports is not generally an option, because the pipeline, storage, refinery, and chemical plant infrastructure that is driving this transportation demand is in Houston. This makes improving the safety and throughput of the Port of Houston a critical issue for energy cargoes.

While Houston poses some unique challenges, similar congestion issues exist in Corpus Christi. A widening and deepening project is currently underway there. Other ports have expansion projects in various stages of study, authorization, and construction.

Just as in the other transportation modes, the number, size, and features of the marine petroleum transport fleet reflect market demand. Although market participants regularly construct replacement tonnage for older equipment, investments in new capacity generally depend on a market signal from customers, often in the form of long-term contracts, especially for more speculative markets. As new regulatory requirements are imposed, this can impact the decision of a vessel owner as to whether to upgrade a vessel or retire it. The requirement for double hull vessels in the Oil Pollution Act of 1990 drove investment in new vessels and forced the retirement of single-hull vessels. More recently, requirements for the installation of ballast water treatment systems have resulted in accelerated retirement of some vessels.

4. Resiliency — Marine

The marine transportation system is one component of the interdependent system of options for petroleum transportation. It is generally viewed as less efficient than pipelines for routes and products for which a pipeline is available. However, it is considered preferable to rail or trucking on routes capable of being served by water. It should be noted that some cargoes carried by marine are not capable of being transported by pipeline, including residual oil products and certain high purity products and feedstocks. These cargoes commonly travel by water even on routes served by pipelines. If these products cannot move by water, this can impact the ability of a refinery to remain in operation, even though its crude oil is supplied by pipeline and its primary products are delivered by pipeline.

Marine transportation offers optionality to shippers, which enhances the resiliency of the petroleum manufacturing and distribution system. When a disruption occurs in an area served by water, it is common for additional marine assets to be directed to the area to bring in needed products or feedstocks and take away or store excess cargoes. Because marine cargoes can be routed and rerouted to alternate ports and terminals, this provides optionality that fixed pipelines cannot provide. When pipeline disruptions have occurred, marine assets have been deployed to offset the lost pipeline capacity.

While the marine transportation system is itself subject to disruption due to weather or human factors, government and industry take steps to minimize disruptions. For significant port disruptions, the U.S. Coast Guard will establish a Marine Transportation System Recovery Unit within its sector command structure, with the role of focusing on restoring commerce. When aids to navigation such as buoys and channel markers are destroyed by a storm or flood, the Coast Guard will send teams and equipment into the area to assist in remarking waterways as soon as is practicable. The U.S. Army Corps of Engineers will take the lead in removing obstructions to waterways and conducting any required emergency dredging.

Industry interacts with the Coast Guard and Corps through Port Coordination Teams, which serve as information clearinghouses. Participants include local facilities and terminals, deep and shallow draft vessel operators, pilots, port authorities, and other stakeholders. One common function of a port coordination team is to monitor the status of local refineries and other facilities; and if a cargo needs to be brought in or taken out to keep the facility operating, these cargoes can be expedited and given head of the line privileges. Industry groups, including the Gulf Intracoastal Canal Association, have developed Joint Hurricane Team protocols with the Coast Guard, Corps, and other agencies that formalize the provision of industry resources to help in waterways restoration following hurricanes. These can include aid to navigation surveys and replacements, side scan sonar evaluations of channel depths and obstructions, and provision of other specialized materials or services.

Deepwater ports can enhance resiliency of the overall petroleum transportation system by eliminating some risks associated with coastal ports. While a deepwater terminal is subject to collision damage just as is a shoreside terminal, and deepwater ports can be damaged in a hurricane, they are constructed in deep water, therefor they lack the risk associated with the need for dredging. Because of their physical separation from other infrastructure, they are less likely to be impacted by some of the factors that can shut down a shoreside terminal, such as nearby hazardous material releases or a casualty that blocks a channel. They are not impacted by general port congestion that can result in delays in reaching shoreside terminals.

One benefit of marine transportation in a resiliency sense is the self-contained nature of marine vessels. A ship or tug-tow combination provides substantial fuel and water capacity, has berthing and messing for its crew, generates its own electricity, and can operate even when shoreside power is unavailable and roads are impassable. Following Hurricane Katrina, numerous vessels were pressed into service to provide housing and support for responders sent to aid residents. Marine traffic was restored through the New Orleans area well before the other modes were able to function. However, even if the marine transportation system is fully functioning, there can be bottlenecks due to the inability of terminals to provide and receive product due to lack of power, facility damage, or personnel shortages.

a. Strengths and Exposures

With respect to the overall resiliency of the federal assets of the marine transportation system, there are positives and negatives. On the positive side, the system generally functions well, notwithstanding chronic underfunding for maintenance and repairs and infrastructure that in many cases is well beyond its economic design life. On the negative side, the continued lack of investment creates mid-to-long-term risk of failures in the system. It should be noted that the common planning philosophy that suggests if one coastal port becomes inoperable, cargo can simply be diverted to another port and transported from there to its ultimate destination does not apply to petroleum cargoes in the same way as it might to containerized cargo or other types of freight. Petroleum supply chains rely on the specialized terminals, pipeline connections, and refineries that are in certain ports. In many cases, means may not exist to transfer petroleum cargoes to their needed destinations if the vessel is diverted from its intended port.

On the inland side, the waterways are truly a system. For cargo on one end of the system to reach a destination on the other end, all infrastructure components along the way must be functional. On the Gulf Intracoastal Waterway, a key petroleum transportation artery, locks are used in a number of places to facilitate crossing rivers and to prevent saltwater intrusion into freshwater basins. Most of these locks are single chamber facilities, which means if that chamber fails, the lock could be rendered impassible. Following hurricanes, flooding on the rivers that cross the waterway, such as the Brazos and Colorado Rivers in Texas, can greatly impede barge traffic. In Louisiana, the Mermentau River basin is protected from saltwater incursion by the Calcasieu Lock on the west and the Leland Bowman Lock on the east. The control manual for these facilities directs that the primary purpose of these structures is flood control, not navigation, so when the Mermentau basin is flooded following a hurricane, the Corps will open the lock gates to facilitate draining water out of the basin, even if this creates currents that make it dangerous or impossible for towboats and barges to traverse the locks. At a time when the refining and petrochemical industries are already stressed from storm related issues, this transportation bottleneck that impacts all barge traffic between Lake Charles, Louisiana, and points to the west and east of Lake Charles can cause great concern and further issues for the resumption of normal operations.

On the Upper Mississippi, Ohio, Illinois, Columbia/Snake, and other rivers, dams are required to maintain navigable pool depths and locks are needed to navigate past the dams. Some dams have two sets of locks, providing a primary and back-up chamber, but others do not. A closure of any lock on a river prevents movement of cargo beyond that point in either direction. The Corps reports that their maintenance budgets have prevented proper maintenance of the lock and dam system, requiring them to resort to fix as fails or fail to fix strategies in some locations. Unscheduled closures of locks have been an issue of increasing concern as the system ages and as maintenance needs have increased. Recent increases in the Corps Operations and Maintenance appropriations are hoped to reverse the trend of increasing failures.

The system for capital replacements on the inland system has been challenged for decades, although there have been some bright spots of late. There is at least an $8 billion backlog of authorized projects that have not been constructed. One example is the Inner Harbor Navigation Lock in New Orleans, Louisiana. It was originally authorized for replacement by Congress in 1956, but the project has faced repeated delays due to design changes, litigation brought by community opponents, and other factors. The project is currently undergoing yet another reevaluation and when construction might resume is unknown.

On the Ohio River, construction of the Olmsted Lock and Dam project was recently completed. This project was finished decades after it was supposed to have been completed and was about two billion dollars over budget. The negative experience at this project led to a reevaluation of the Corps project delivery process and the implementation of new processes at Olmsted. As a result, the portion of the project completed after these changes were made were completed early and on budget. Navigation stakeholders believe that similar adjustments at other projects will help control cost overruns and completion delays.

Findings:

- The Port of Houston is an essential energy port for the United States and presents a unique set of circumstances that must be considered in determining the proper approach to channel modifications.

- The inland waterway system requires proper investment in maintenance and capital improvements if it is to remain a reliable source of flexible energy transportation for the nation.

- As with other modes, the market will not create capacity simply for the sake of providing resiliency. However, capacity can be added when the market signals the need.

- Dredging ports used for energy transportation to their authorized depths and widths, and in some cases, increasing that authorized depth and width, will increase the efficiency of marine transportation. The government collects a harbor maintenance tax to maintain all deep-draft ports to their authorized depth and width.

The NPC recommends that:

- The Houston Ship Channel study being undertaken by the U.S. Army Corps of Engineers should account for the unique nature of the Port of Houston and should recommend the widening of the channel to accommodate safe and efficient two-way traffic of all current and foreseen vessels calling in Houston.

- Congress should fully appropriate revenue coming into the Inland Waterways Trust Fund to fully maintain all U.S. port infrastructure at their authorized dimensions.

- Where warranted, Congress should authorize widening and/or deepening of channels to increase the capacity of ports to safely and efficiently transport energy cargoes.

- Congress should fully appropriate the revenue coming into the Harbor Maintenance Trust Fund to fully maintain all U.S. port infrastructure at their authorized dimensions.

5. Trucking Infrastructure

Trucking is often the first or final mile in moving product to the end user, although that does not mean that hazmat trucking is all short haul. This mode has become more important; but it has also become more difficult due to government regulations, driver and hours of service regulations, equipment changes and cost increases, technology improvements, repair and maintenance costs, challenges with repair facilities, and a technician shortage along with qualified driver shortages. The strength of trucking is that a truck can go almost anywhere, at any time, and carry almost any commodity needed to any destination needed. Only severe weather, such as flooding and ice storms, can impede the system; but even these events do not stop it.

Owner operators (O/O) form a large part of the trucking for hire fleet in dry commodities; but in tanker applications, it is largely a company-owned and -operated fleet. Although there are a smaller percentage of O/O's, tanker applications also have, for the most part, shorter hauls and are home nightly or more often than over the road truckers. This typically makes it easier to find and retain drivers. O/O's also earn more revenue, and drivers on average earn higher wages than over the road drivers. Trailers are durable and require minimal maintenance, where box vans get worn out much quicker because of the abuse they take in warehouses, lots, loaders, unloaders, and yard movements.

Trucking risks exist, which primarily involve road condition and traffic. There are also risks associated with drivers' hours of service, delays (called demurrage), and additional miles driven to meet hazmat route restrictions for roads and bridges and tunnels. Risks can also involve driver errors or injuries, and equipment failures. As with most operations involving hazmat, regulation increases the cost of compliance relative to over the road trucking, and insurance rates for hazmat transportation continue to increase, even for the best in class carriers.

Although all mobile transportation modes are not the primary or most economical way to move energy products, some examples of trucking's advantages are evident:

- Crude oil was trucked during 2018 and 2019 from the Midland/Odessa area to the Gulf Coast, mainly Corpus Christi. Given a crude oil production uptick with insufficient pipeline capacity to move it, trucks were relied upon to get the product to market, moving 160 barrels at a time. As pipeline projects come online, trucks will stop hauling in these markets and seek another opportunity.

- Refined product shortage in the Amarillo market during 2019 created a need for product from other origins. Oklahoma City quickly originated many truck shipments to meet the region's business needs.

6. Resiliency — Trucking

Weather events, particularly hurricanes and tropical storms, present substantial supply chain issues. Resulting power outages impact product terminals, pipeline, and ports. Rail, maritime, and truck options immediately become very valuable, reacting to the product shortages that quickly develop in those hard to reach areas that suffer from the outage of traditional supply chains. Polar vortex's, earthquakes, blizzards, and regional events all cause trucking issues, but trucking offers the advantage of generally recovering quickly from these events.

Finding: Mobile assets such as railcars, trucks, and barges allow for commercial repurposing and provide greater flexibility than static infrastructure.

The NPC recommends the following:

- Create a regulatory environment that supports new infrastructure projects in areas where there are supply and demand imbalances.

- When possible, consider increasing the geographic diversity for all types of facilities, including new export facilities.

- Evaluate opportunities to decongest ship channels on the Gulf Coast to support the increased ship traffic.

- Adopt a review, revise, and refine approach to studying resiliency and infrastructure more consistently to address the constant changes to supply and demand.

III. INFRASTRUCTURE DEVELOPMENT AND REGIONAL CONSTRAINTS

A. Basin-Specific Challenges

Findings:

- Several critical infrastructure bottlenecks exist: natural gas pipeline access to New England/New York, Port of Houston capacity, and oil and natural gas export capability.

- Each of the United States' large production areas is unique, not only in its location and distance to primary markets, but in the mix of crude oil, natural gas, and NGLs produced there.

For example, production in the dry Marcellus region in northeastern Pennsylvania is almost entirely natural gas, with minimal NGL content and no crude oil. In the Permian Basin, in contrast, the focus is on crude oil production, but wells there also produce large volumes of associated natural gas and NGLs. Because the infrastructure that is needed in particular production areas is so site-specific, it is helpful to consider the recent and current experiences of a few representative areas facing different challenges.

1. Permian Basin — Crude Oil, Natural Gas, and NGLs

The Permian Basin is the most prolific energy-producing region in the United States, driven primarily by its highly attractive crude oil economics, and the performance of this basin is crucial to the total U.S. production profile. The Permian Basin also yields large volumes of natural gas and NGLs, and due to the region's proximity to Gulf Coast refining, petrochemical, and export markets, most Permian Basin production moves by pipeline to the Texas coast.

As Permian Basin crude oil production has grown over the past 8 years, the basin has experienced three periods of constrained pipeline takeaway capacity, resulting in limitations on flows of Permian Basin crude oil to refinery and export markets, as well as depressed Permian Basin crude oil prices. In all three periods, new pipeline construction, mostly to the Texas coast, relieved the capacity constraints, allowing the growth in Permian Basin crude oil production to resume. This pattern of production growth, constrained pipeline capacity, pipeline construction, and capacity relief will continue. Thus far infrastructure development has generally kept up with production growth. But as described earlier, a number of key new pipeline projects are critical to transport oil, natural gas, and NGLs, from the Permian Basin to export facilities on the Gulf Coast.

As noted earlier, most Permian Basin natural gas and NGL production is associated with crude oil wells, meaning that the ability to produce crude oil is dependent on the ability to take away the gas and NGLs produced alongside the crude oil. Permian Basin natural gas and NGLs have also experienced cycles of takeaway capacity shortfall, infrastructure development, and capacity relief, although on different timelines than the crude oil market. The implication is that at any one time, Permian Basin takeaway capacity for crude oil, natural gas, or NGLs may be constrained, leading to situations in which producers without firm takeaway capacity for all three commodities may need to defer their drilling programs until new capacity is built. Thus, a lack of natural gas pipeline capacity can constrain crude oil production, or conversely the lack of crude oil capacity can constrain gas production.

While this dynamic of triple-play wells with high rates of crude oil, natural gas, and NGL production from most new wells is not exclusive to the Permian Basin, rapid production growth in all three commodity groups has made the impact of this dynamic most consequential in the Permian Basin. As a result, infrastructure planning for future Permian Basin production growth must be integrated across commodity groups and coordinated to minimize periods of constrained pipeline takeaway capacity in any one commodity.

2. Appalachia (Marcellus/Utica) — Natural Gas

Two important characteristics distinguish the combined Marcellus/Utica play. First, Appalachian production is predominantly natural gas, along with moderate volumes of NGLs and small quantities of crude oil—mostly field condensates. Second, Marcellus/Utica natural gas production is adjacent to the United States' largest domestic gas demand regions: the Northeast and Midwest. These two features of the Appalachian market have impacted the evolution of the region's pipeline infrastructure.

Prior to the shale development, only a small portion of the Northeast's and Midwest's natural gas demand was met with production from within Appalachia. Instead, most of the natural gas supply was sourced from faraway supply regions—the Gulf Coast, the Southwest, the midcontinent, and Canada. Many of the legacy pipelines used to make these deliveries had been in this service since the 1940s and 1950s and were developed to satisfy weather-sensitive residential and commercial requirements in the demand regions.

As shale production started to increase in the early 2010s, companies with legacy long-haul pipelines with routes traversing the Marcellus/Utica responded to the need to provide takeaway capacity out of the basin by constructing new receipt points in the Appalachian production area. As flows into these receipt points increased, Marcellus/Utica production displaced gas that had been supplied from the Gulf Coast and other distant locales. As a result, a Northeast or Midwest gas customer—such as an LDC—buying gas from, for example, South Texas would physically take the gas that had entered the pipeline in Appalachia, while customers along the more southerly reaches of the long-haul pipeline would take the South Texas gas physically but treat it as a purchase from the Marcellus/Utica producer. These so-called backhauls provided needed takeaway capacity out of the prolific Marcellus/Utica basin without having to wait for new Northeast pipeline infrastructure to be built.

As Marcellus/Utica production continued to grow, pipelines in the region eventually were receiving more gas than could be displaced from their legacy upstream receipt points—in other words, they ran out of backhaul capability. This required the development of new infrastructure to allow the physical reversal of pipeline flows, primarily from the Appalachian region to Gulf Coast delivery points, where Marcellus/Utica gas could replace declining production from other basins, such as the Offshore Gulf of Mexico. Eventually, even full reversal of most of the legacy pipelines in the region was inadequate to meet the need for pipeline takeaway capacity out of the Appalachian region, and several new greenfield pipeline projects were built to meet the needs of Marcellus/Utica producers.

As Appalachian production growth continues, still more pipeline capacity will be needed to bring this production to market. Some of this capacity could provide increased supplies into Northeast demand regions. However, pipeline construction to New York, New England, and some other regional markets has been constrained by regulatory and permitting delays or even denials, public protest, political issues, and long-standing market structures. These issues have made it difficult for midstream companies to line up the necessary commitments to underwrite much-needed pipelines. Accordingly, most of the production growth from Marcellus/Utica region will most likely move to Gulf Coast LNG export markets. As a result, additional capacity to move Appalachian gas south will need to be developed.

3. Appalachia (Marcellus/Utica) — NGLs

Prior to the shale development, NGL volumes produced in Appalachia were miniscule, both in terms of regional supply and overall U.S. production. Volumes were limited to production from a few small, legacy processing plants and fractionators. Almost all of the volumes were transported by truck or rail, and no ethane was recovered—instead, all ethane from Appalachian production was rejected into natural gas and sold as part of the natural gas stream.

The first phase of Marcellus/Utica NGL market development began in 2013, when new processing and fractionation facilities in western Pennsylvania started up at the same time new ethane pipeline capacity came online. Most of the processing, fractionation, and pipeline takeaway capacity was new greenfield construction required to meet the needs of regional producers to extract and transport their NGLs. Except for ethane, which because of its special characteristics must move from fractionation facilities via pipeline, other NGLs (called C3+, including propane, normal butane, isobutane, and natural gasoline) have continued to rely largely on rail and trucks for transportation.

As wet, NGL-rich gas production continued to grow in western Pennsylvania, northern West Virginia and eastern Ohio, several new gas processing plants were built. Also, new pipelines were built to move Appalachian ethane to Sarnia, Ontario, and Mont Belvieu, Texas, and new de-ethanization facilities were developed in the wet Marcellus/Utica to feed these pipes.

Although there were a few underground NGL storage facilities in the region (such as the Bath facility in upstate New York), most NGL storage was in aboveground tankage, whose construction cost is generally much more expensive per barrel than underground storage. There is essentially no storage capacity for ethane in the Appalachian region, a factor that helped drive the development of a unique system: gas pipeline-connected de-ethanization facilities at MPLX/MarkWest gas processing plants that provide the ability to reject large volumes of ethane if ethane takeaway capacity is offline. In effect, ethane rejection serves as a relief valve for ethane that cannot be transported to another market, similar to the use of NGL storage in the Gulf Coast region and the midcontinent.

Two very important pieces of Appalachian NGL infrastructure first came online in 2014 with the repurposing of the Mariner East 1 pipeline to flow NGLs to a refurbished Marcus Hook export terminal near Philadelphia. As a result, Marcellus/Utica NGLs could be exported directly to global markets. Starting with LPGs (propane and butane) in late 2014, Marcus Hook infrastructure by early 2016 was built out to handle ethane exports as well. In late 2018, the Mariner East 2 pipeline was completed, allowing increased NGL exports from Marcus Hook.

As with other infrastructure developments, Appalachian NGL production could not have increased without the capability to process and move that production to market. As production continues to increase, still more processing plants, fractionators, and pipelines will be needed to move incremental NGL volumes to markets.

4. Bakken — Crude Oil

Located mostly in western North Dakota, production areas in the Williston/Bakken region had limited pipeline and other energy infrastructure prior to the widespread application of horizontal drilling and hydraulic fracturing to the Bakken Shale in 2008. Crude oil production growth quickly overwhelmed local markets and the limited pipeline access. Due to long distances between the Bakken and refinery markets suitable to run incremental Bakken barrels, pipeline capacity would be expensive and take years to complete. Consequently, Bakken producers committed to support the construction of crude-by-rail facilities. These terminals were built to take advantage of rail networks that primarily supported agriculture in the region. Most were built to handle unit trains of more than 100 crude oil tank cars each. These tank cars could be loaded quickly and moved without delay to unloading terminals with access to specific refineries or to crude oil distribution hubs with the ability to move barrels to multiple refineries.

Although crude-by-rail transportation was more expensive than pipeline transportation, there were advantages. Moving crude oil on rail tank cars provided destination optionality—that is, crude oil could be moved to the highest-price market, thus satisfying the highest regional demand at a point in time. In the early 2010s, regional crude oil prices supported rail transportation to markets on the East, West, and Gulf Coasts. Bakken crude-by-rail terminals proliferated, with 21 facilities operating by 2015. But that same year, crude oil prices declined sharply, slowing drilling activity in the Bakken, and regional price differentials no longer justified the cost of transporting crude oil by rail. As a result, many of the new crude-by-rail facilities were idled as soon as they were completed. But crude oil that was already being produced needed to be moved to market. At that point, several new pipeline projects were explored or developed, with one large project—the Dakota Access Pipeline (DAPL)—eventually being built. When DAPL came online in mid-2017, even more crude-by-rail facilities were shut down. By late 2018, the DAPL line was highly utilized and a few of the crude-by-rail terminals had restarted operations to provide additional takeaway capacity. Today the potential for expanding DAPL capacity and building another new pipeline system out of the region are alternatives being discussed by market participants.

Finding: To continue to support the development of supply, investment in new infrastructure is necessary.

5. Flaring and Infrastructure Constraints

Energy producers are incentivized to capture all of the molecules produced and to deliver them to the market and consumers. Intermittent flaring that occurs as a result of routine well testing, production facility process shutdowns, or facility and pipeline infrastructure maintenance, are normal aspects of safe oil and natural gas production.

Energy producers rely heavily on midstream operators for natural gas pipeline infrastructure. Industry seeks to connect to natural gas sales infrastructure as soon as possible, striving to have infrastructure in place before bringing a well into production.

Permitting, construction, and equipment delays mean that this critical infrastructure has been stressed and has not been able to keep up with demand. When companies develop gas-capture infrastructure, obtaining rights-of-way to lay new pipelines across multiple property owners takes time. When federal or tribal lands are involved, delays can be even greater. This time-consuming regulatory process can take 2 years or more, and approval has even been denied in some instances. Two examples of this are the Hawkeye Pipeline in North Dakota, which took more than 3 years for Bureau of Land Management approval and the Lost Bridge Pipeline, also in North Dakota, which was held up by the tribes and denied by the U.S. Forest Service.

In some cases, industry will delay or shut-in production until sufficient pipeline infrastructure is available to minimize gas flaring.

Finding: In places like the Permian Basin and the Bakken, crude oil can only be produced if the natural gas that comes with it is produced. So, if producers lack sufficient gas pipeline infrastructure, all energy products are shut in. All of this comes with direct impact to the market, consumers, and royalty owners.

The oil and natural gas industry is actively evaluating and deploying alternatives to flaring; including operational and maintenance improvements and the use of recovery processes and gas-fired power generation for local site power needs. But these are small/interim steps to alleviate flaring in addition to the longer-term solution of the construction of much-needed infrastructure to accommodate gas pipeline takeaway capacity.

Companies want to capture 100% of the natural gas they produce, but to do that they need full engagement by the industry, state, counties, landowners, and other key stakeholders to build the infrastructure needed to move natural gas to market in the safest way possible.

Finding: Flaring is an important issue that energy producers take very seriously. The industry makes every effort to reduce flaring of natural gas, but sometimes must do so for safety reasons, regulatory requirements, or lack of sufficient infrastructure to move the natural gas to market.

The NPC recommends that industry and federal and state agencies should continue to work together to ensure sufficient natural gas transportation infrastructure is in place on pace with development and production plans in growth basins to reduce flaring.

6. The West Coast (PADD 5)

In the West Coast, infrastructure development is impacted by permitting restrictions enacted by various state governmental entities resulting in market inefficiencies.

Between 2004 and 2014, the West Coast enjoyed a crude oil acquisition cost advantage versus the East Coast of between \$6.81/barrel (2012) and \$1.04/barrel (2014).[68] From 2015 to 2018 the feedstock cost averaged \$0.56/barrel advantage for the West Coast, despite the West Coast average crude oil slate being 5 to 6 degrees API heavier and having roughly 0.5% higher sulfur content.[69]

In 2018, the U.S. West Coast suffered from the highest crude oil acquisition cost of any U.S.

68 U.S. Energy Information Administration, "Refiner Acquisition Cost of Crude Oil — Composite," Petroleum & Other Liquids, http://www.eia.gov/dnav/pet/pet_pri_rac2_a_epc0_pct_dpbbl_a.htm. (accessed November 6, 2019).

69 U.S. Energy Information Administration, "Crude Oil Input Qualities," Petroleum & Other Liquids, https://www.eia.gov/dnav/pet/PET_PNP_CRQ_A_EPC0_YCG_D_A.htm (accessed November 6, 2019).

region.[70] These higher acquisition costs can be expected to flow through the production-refinery-delivery supply chain to reflect in higher prices to end-use consumers.

It is notable that the West Coast is substantially advantaged geographically versus the East Coast for sourcing from key U.S. and Canadian crude oil basins. To the extent that Washington State refineries were more fully sourced from North Dakota and Canadian sources, Alaska crude oils could shift to California refineries. This shift would result in reduced cost to refineries and reduced inbound crude oil tanker traffic in Puget Sound.

The higher acquisition cost in the West Coast can generally be attributed to (1) constrained logistics in moving crude oil from lower-cost U.S. and Canadian sources, (2) cost of regulation, and (3) more distant shipping from the Middle East, West Africa, and other swing sources when domestic sources are constrained.

Focusing first on constrained logistics, the West Coast has been notable for its adversity to permitting fossil fuel facilities. State and local entities have denied permits or caused investor project withdrawal from the following proposed crude oil delivery facilities:

- Valero's refinery at Benicia, California[71]
- Shell's refinery at Anacortes, Washington[72]
- Phillips 66's refinery at Santa Maria, California[73]
- Westway Terminal Company LLC and Imperium Terminal Services LLC at Grays Harbor, Washington[74]
- Vancouver Energy's rail-to-water facility at Vancouver, Washington.[75]

In addition, California, Oregon, and Washington have sought to regulate the flow of crude oil and other petroleum products in a manner that increases supply chain cost.

- Washington tanker standards (struck down by U.S. Supreme Court in 1999)[76]
- California tax on crude oil shipments (instituted 2014 and in court challenge)[77]
- Washington restrictions on rail-delivered crude oil vapor pressure[78]
- Washington additional tug requirement.[79]

Lack of adequate new infrastructure and adverse regulation leave many West Coast refiners few alternatives other than imported oil and local sourcing from depleting domestic basins such as Kern County, California. Taken in sum, the West Coast regulatory environment has exacted a substantial feedstock cost on U.S. West Coast refiners, which has ultimately been borne by consumers in the form of higher prices for refined products (Figure 2-82).

70 U.S. Energy Information Administration, "Refiner Acquisition Cost of Crude Oil — Composite," Petroleum & Other Liquids, http://www.eia.gov/dnav/pet/pet_pri_rac2_a_epc0_pct_dpbbl_a.htm (accessed November 6, 2019).

71 The City of Benicia California, "Valero Crude by Rail," October 4, 2016, https://www.ci.benicia.ca.us/cbr.

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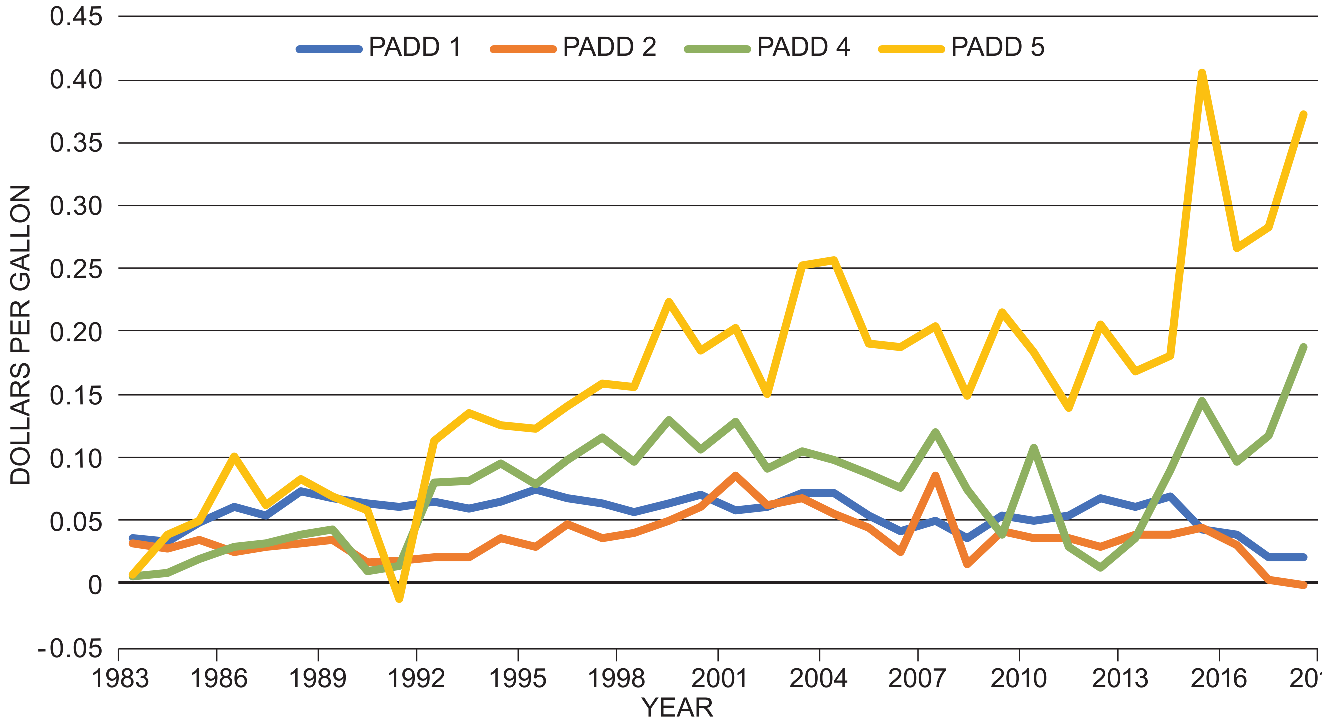
78 Washington State Engrossed Substitute Senate Bill 5579, Chapter 354, Laws of 2019, 66th Legislature, 2019 Regular Session, "Crude Oil by Rail—Vapor Pressure, Effective Date: July 28, 2019," http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session%20Laws/Senate/5579-S.SL.pdf#page=1.

79 Allison, J., "Bill seeks to make oil transport safer in Washington waters," Anacortes.com, March 20, 2019, https://www.goskagit.com/anacortes/news/bill-seeks-to-make-oil-transport-safer-in-washington-waters/article_7d5549bc-4a97-11e9-b25d-ff01a71af6e3.html. The original regulation requiring a tug for all laden tankers is WAC 363-116-500 "Tug escort requirements for oil tankers," https://apps.leg.wa.gov/WAC/default.aspx?cite=363-116-500.



Source: EIA, Petroleum & Other Liquids, Prices, Petroleum Product Retail and Wholesale Prices by U.S. PADD District and State.

Figure 2-82. *Difference in Price – Regular Gasoline Wholesale Compared to Resale by PADD*

IV. INTERDEPENDENCIES BETWEEN INFRASTRUCTURE DEVELOPMENT AND ANCILLARY MARKETS

A. Crude Oil Supply and Export Infrastructure

The expected increase in crude oil exports will face multiple challenges. Within the crude oil market, domestic infrastructure will be required to serve both foreign waterborne imports and growing exports. Even on an isolated basis, the ability to support these bidirectional flows will require new infrastructure and logistical coordination. However, these challenges will be further amplified given the concurrent expansion of export infrastructure for NGL, LNG, and other associated commodities.

The expected increase in exports will require both dedicated export infrastructure and common infrastructure such as marine waterways and ports. Dredging and maintenance of key marine waterways and ports will be imperative. New and expansions to existing pipelines are also critical to moving oil, natural gas, refined fuels, and NGLs to the Gulf Coast export terminals.

B. Development Challenges

Considerable production growth across all commodity value chains requires concentrated use of overlapping resources. Despite differences in operations, crude oil, natural gas, and NGL pipelines utilize many of the same resources such as pipeline contractors, steel mills, pumps, valves, meters, and other associated equipment.

C. Crude Oil Exploration and Production

The process of drilling new wells to bring crude oil and natural gasoline out of the ground requires the use of No. 2 Ultra Low Sulfur Diesel (ULSD) to power the equipment. Additionally, many of the wells that are being drilled in remote locations do not have immediate access to gathering infrastructure. This type of operation requires the use of tank trucks to transport the products to a gathering facility to be further moved across the region/country on long-haul pipelines or rail infrastructure. In the case rail infrastructure and movements are needed, the locomotives also require ULSD for power generation. Therefore, the demand for ULSD in the drilling regions is directly tied to the number of rigs that are drilling for the product and the mode of transportation being used for the movement of the product to its ultimate destination.

A secondary impact of technological advancements with the United States regarding the drilling for crude oil is that it has stabilized the market price for crude oil and created a pricing advantage for domestic refineries. The refineries can take advantage of this lower priced crude oil and process it for a higher profit. The increased profit can then be used to fund expansion projects that lead to more crude oil being utilized in domestic refineries and more refined production in the United States. The owners of the refined products infrastructure must be able to put themselves in a situation to take this incremental capacity and move it to demand centers that need incremental product.

D. Consumer Transportation and Supply

The movement of refined products from supply centers to demand centers requires the use of energy in many forms. Most of the pumps utilized on pipelines today require electrical capacity in the region to power the motors and push the product to the destination. When the product arrives at a storage and distribution terminal, it is loaded into transport trailers to be trucked to its destination at a retail location. The transport carrying the fuel is powered by diesel. As previously mentioned, if pipeline capacity is not available and product needs to move to a demand center via rail, the locomotive used to pull the rail car is also powered by a diesel engine.

E. Natural Gas

The large and rapid increases in U.S. gas supply that have been generated by the shale development have allowed the United States to move from being relatively undersupplied with natural gas, to being not only self-sufficient but actually oversupplied in the space of just 10 years.

The magnitude of U.S. natural gas abundance has led to a strong and growing export market, requiring the development of multibillion-dollar LNG export terminals and extensive pipeline capacity into Mexico. If this infrastructure development stays on track, the United States will be in the top echelons of natural gas exporters in the next 2 years.

The geographic shift and sheer size of supply growth has caused the need for growth in infrastructure. The first wave of infrastructure growth was accommodated by the repurposing, reversal, and expansion of existing pipelines. This helped manage costs and impacts. However, the next wave underway requires greenfield pipelines, meaning higher costs and strong resistance from environmental groups, landowners, etc. This resistance may create substantial challenges to pipeline growth in terms of regulatory approvals, state permitting, and right-of-way acquisition. Thus, while natural gas has previously enjoyed the advantage of a large existing network of infrastructure as a base, that advantage has become decreased as supply has gone beyond what can be accommodated by simply expanding that network.

The implication is that the future growth in supply that will fill the next wave of LNG exports, allowing the United States to become a dominant player in world energy flows, will depend heavily on building large, costly pipeline systems in a difficult environment, both economically and politically. These investments will ensure security of supply domestically and grow exports of natural gas, both of which will grow the national economy. Consumers will also benefit from this growth through less volatile prices.

1. Natural Gas Infrastructure and the Power Sector

a. Overview

As discussed in Chapter One, Supply and Demand, demand for natural gas in the power sector has increased more than 50% over the last decade. The power sector is expected to increasingly rely upon less-CO_2-intensive fuels, such as natural gas and renewables. Wind and solar supply to the power sector is expected to grow from

18% in 2018 to 31% in 2050.[80] Despite this growth, nonrenewable fuel demand from the power sector will continue and even grow as intermittency limits wind and solar utilization. Power sector demand for natural gas is expected to grow from 34% in 2018 to 39% in 2050.[81]

Low natural gas prices have supported fuel substitution in the power sector, leading to the retirement of coal, oil, and nuclear power plants. Moreover, natural gas power is flexible, responsive, and reliable. Natural gas power can effectively balance the intermittency and variability of renewables. This can enable broader penetration of renewables. Natural gas is the fuel of choice to provide strong grid reinforcement and stability. In conjunction with renewables, this provides the United States with a cost-effective, reliable power supply. Natural gas power also offers the additional benefit of reducing CO_2 emissions versus other nonrenewable fuels.

It is therefore critical to ensure that the nation's gas infrastructure can continue to grow to deliver gas to the power demand centers. This includes natural gas pipelines and gas storage.

Finding: Renewables are expected to be a key component of national power demand. Natural gas is reliable and efficient for baseload electricity generation. Its flexibility also makes it well suited to meet peak demand and back up intermittent renewables.

b. History

The U.S. natural gas infrastructure system was historically sized and built to meet the peak demand needs of the local natural gas utilities (also called local distribution companies, or LDCs) serving heating customers, not natural gas-fired power plants. As previously discussed, the power system is increasingly dependent on natural gas for power generation. The capacity of natural gas infrastructure is not always adequate to deliver all the gas needed for both heating and power generation during winter, especially in New England. Dual-fuel, renewables, energy storage, and LNG can be an important complement to pipeline gas supplies. More pipeline capacity, near real-time purchasing of uninterruptible gas, and flexible contracts are needed to minimize system stress and maintain reliability especially during peak time as permitted.

The high growth rate in gas demand from the power sector will increase seasonal peaks and may increase the need for new storage facilities. The increase of summer peaking electric generation will result in competition for pipeline gas that otherwise would have gone into filling the underground storage facilities described earlier in Section II.D, Natural Gas Infrastructure History and Current State. The current low prices for storage services has reduced the economic incentive to develop additional storage facilities. Additionally, any possible future storage development will be limited due to geological limitations in the different market areas.

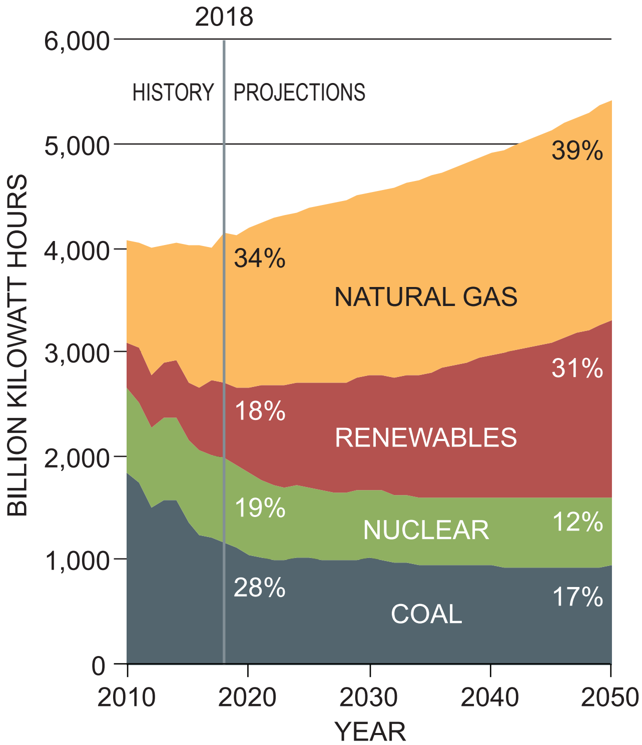
c. Demand for Natural Gas in the Power Sector

Demand for natural gas in the power sector has seen the most growth over the last decade. This demand will continue, under all scenarios, as described in Chapter One, Supply and Demand. Growth has come as a function of long-term stable prices that, at times, results in gas-fired power generation being less expensive than coal-fired power generation. In 2018, natural gas was the single largest domestic generation source, comprising 34% of total U.S. generation (Figure 2-83). Coal, which was the dominant domestic generating source until 2016,[82] comprises the second largest share of generation and capacity in 2018. Power generation fueled by natural gas is projected to continue to grow over the coming decades. It is no surprise that the growth in power sector demand for natural gas is alongside growth for demand of renewables while coal demand is projected to continue to decline. Natural gas power

80 U.S. Energy Information Administration, *Annual Energy Outlook,* 2019 Reference Case.

81 Ibid.

82 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, "Net generation for electric power," *Electric Power Monthly*, October 24, 2019 release.



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

Figure 2-83. *Electricity Generation from Selected Fuels*

is flexible, responsive, and reliable. Natural gas power can effectively balance the intermittency and variability of renewables.

d. Evolution of Power Plants

As described in Chapter One, Supply and Demand, in addition to the high utilization of traditional gas peaking plants, new, more efficient combined-cycle gas turbines (CCGT) 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.[83] 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.[84] This trend is projected to continue in 2019, with 4.5 gigawatts (GW) of coal-fired capacity and 2.2 GW of natural gas-fired capacity expected to retire (Figure 2-84).[85]

The increasing utilization of natural gas, wind, and solar generators in the power sector have led to decreased power sector carbon dioxide (CO_2) emissions. According to an EIA analysis, between 2005 and 2017 power sector CO_2 emissions declined a total of 3,855 million metric tons (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 (Figure 2-85).[86]

More than 5,200 megawatts (MW) of oil, coal, and nuclear power plants will have retired from 2013 to 2022, and another 5,000 MW of coal- and oil-fired generation could retire in coming years (Figure 2-86). These retirements and anticipated development of renewables will require optimization of utility-scale delivery and operating systems to meet larger off-peak swing loads, and growing peak day requirements.

Natural gas is the fuel of choice for a large segment of new power plant proposals, growing up to 37% in 2030 as depicted in Figure 2-87. In some cases, coal-fired power plants are being transitioned to become natural gas-fired power plants. Two such examples are the Stonewall power plant in Loudoun County, Virginia, and the Greenidge Generation facility in New York State.[87]

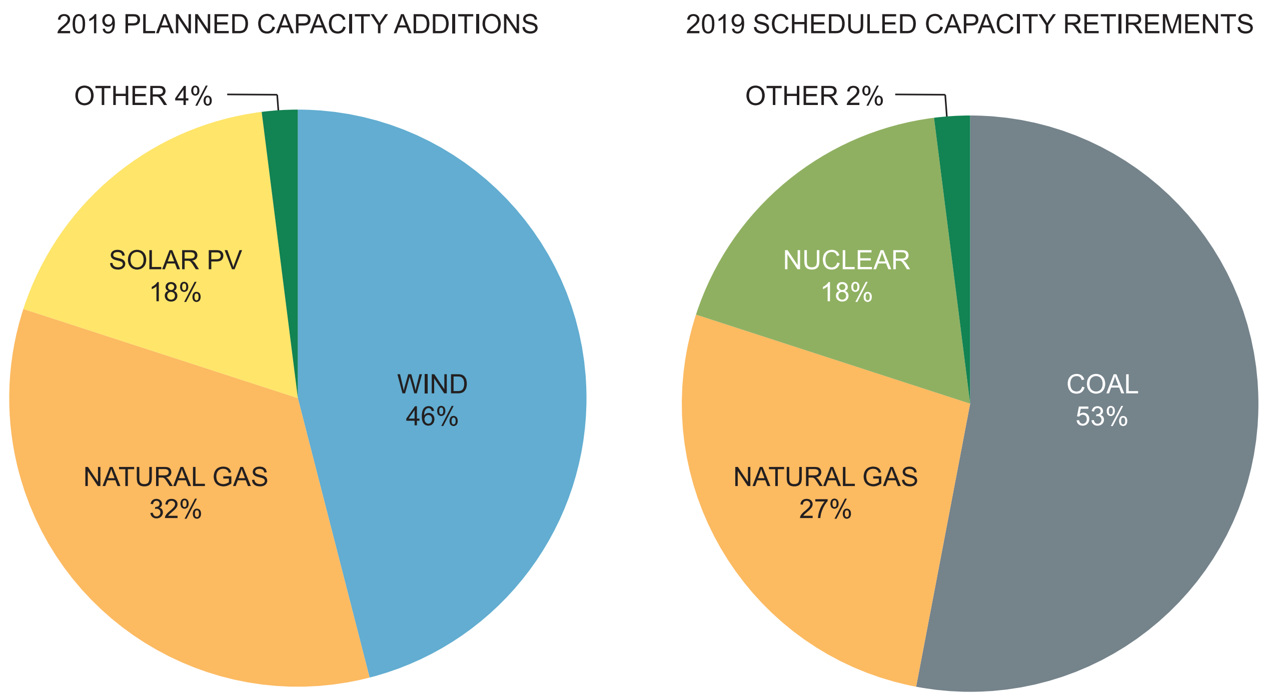
83 U.S. Energy Information Administration, *Today in Energy*, March 11, 2019, https://www.eia.gov/todayinenergy/detail.php?id=38632.

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

85 This is less than the 13.7 GW of coal that retired in 2018, the second highest year for coal retirements. U.S. Energy Information Administration, "New electric generating capacity in 2019 will come from renewables and natural gas," *Today in Energy*, January 10, 2019, https://www.eia.gov/todayinenergy/detail.php?id=37952.

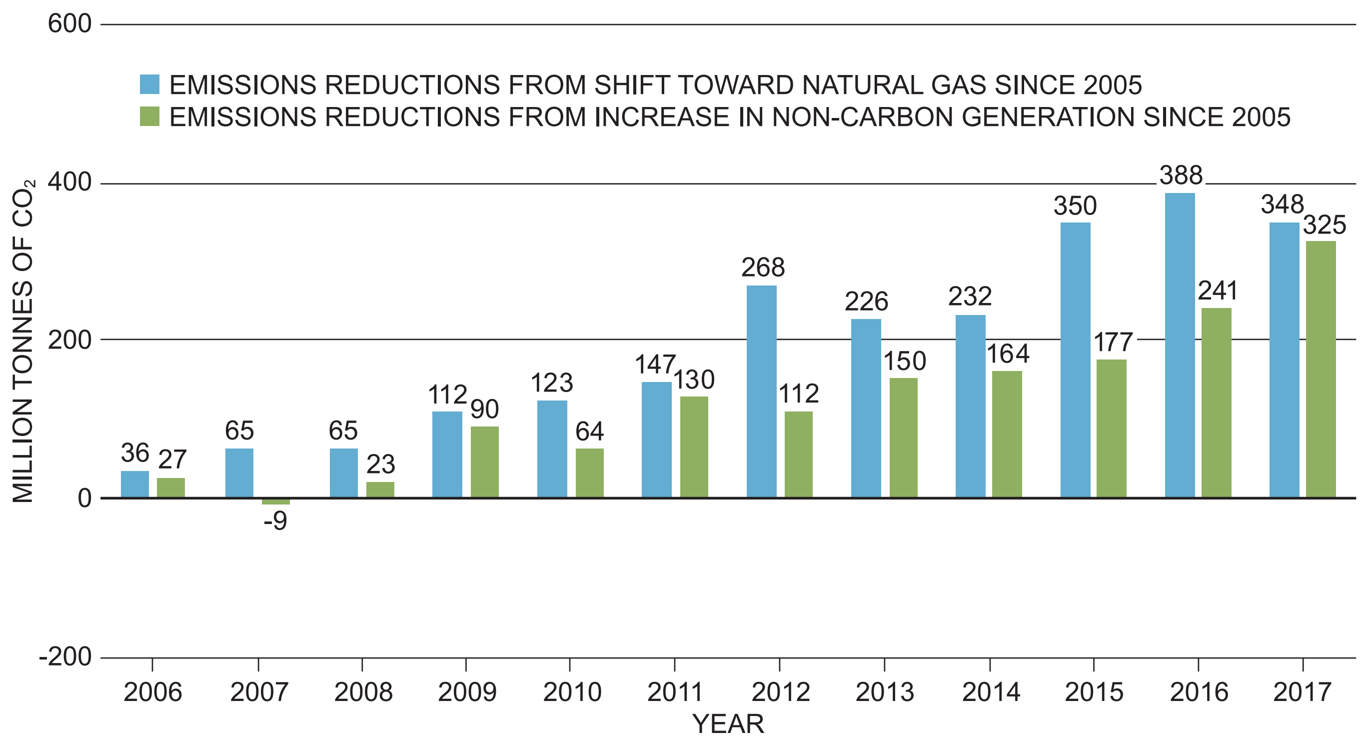
86 U.S. Energy Information Administration, *U.S. Energy-Related Carbon Dioxide Emissions, 2017*, Environment, September 25, 2018, https://www.eia.gov/environment/emissions/carbon/.

87 Chamberlain, G., "Officials celebrate progress at Greenidge Generation power plant," *The Chronicle-Express*, October 19, 2016, https://www.chronicle-express.com/news/20161019/officials-celebrate-progress-at-greenidge-generation-power-plant (accessed August 1, 2019); and Panda Power Funds, *Panda Stonewall Power Project,* http://www.pandafunds.com/invest/stonewall/ (accessed August 1, 2019).



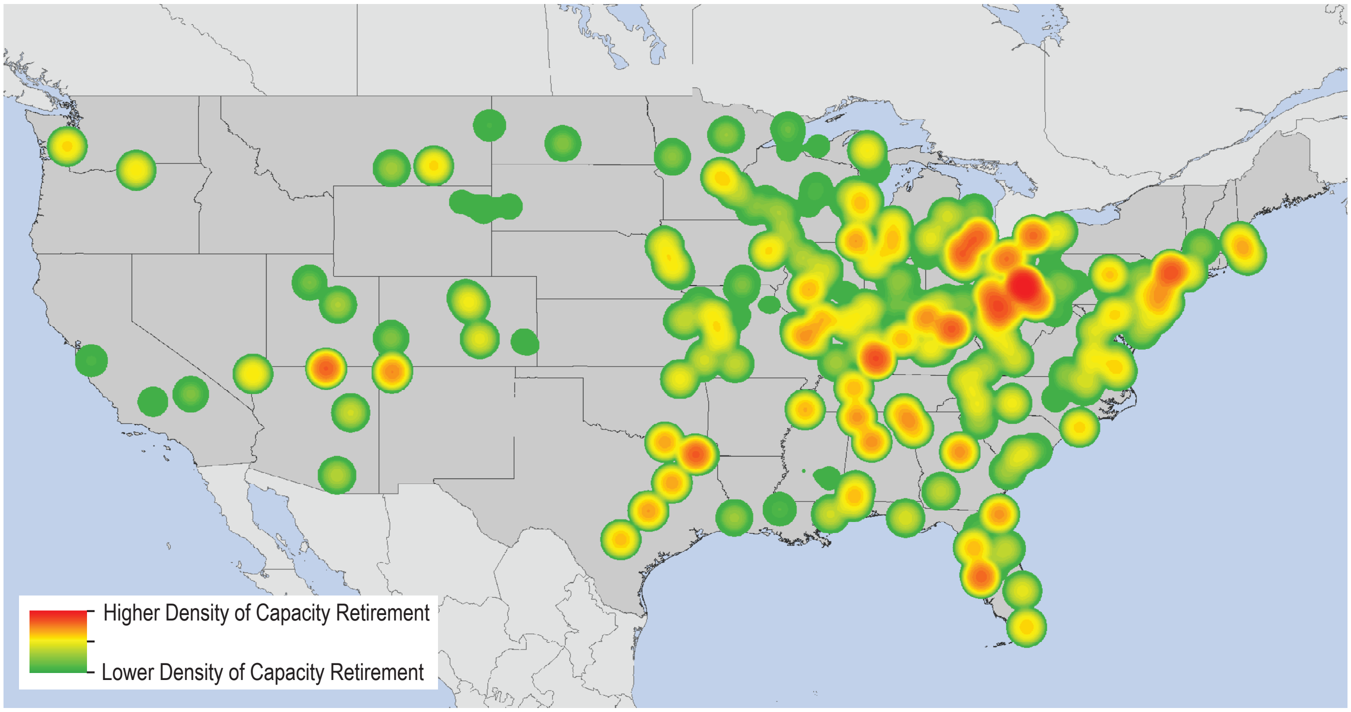
Source: EIA, *Today in Energy*, January 10, 2019.

Figure 2-84. *2019 Planned Capacity Additions and Scheduled Capacity Retirements*



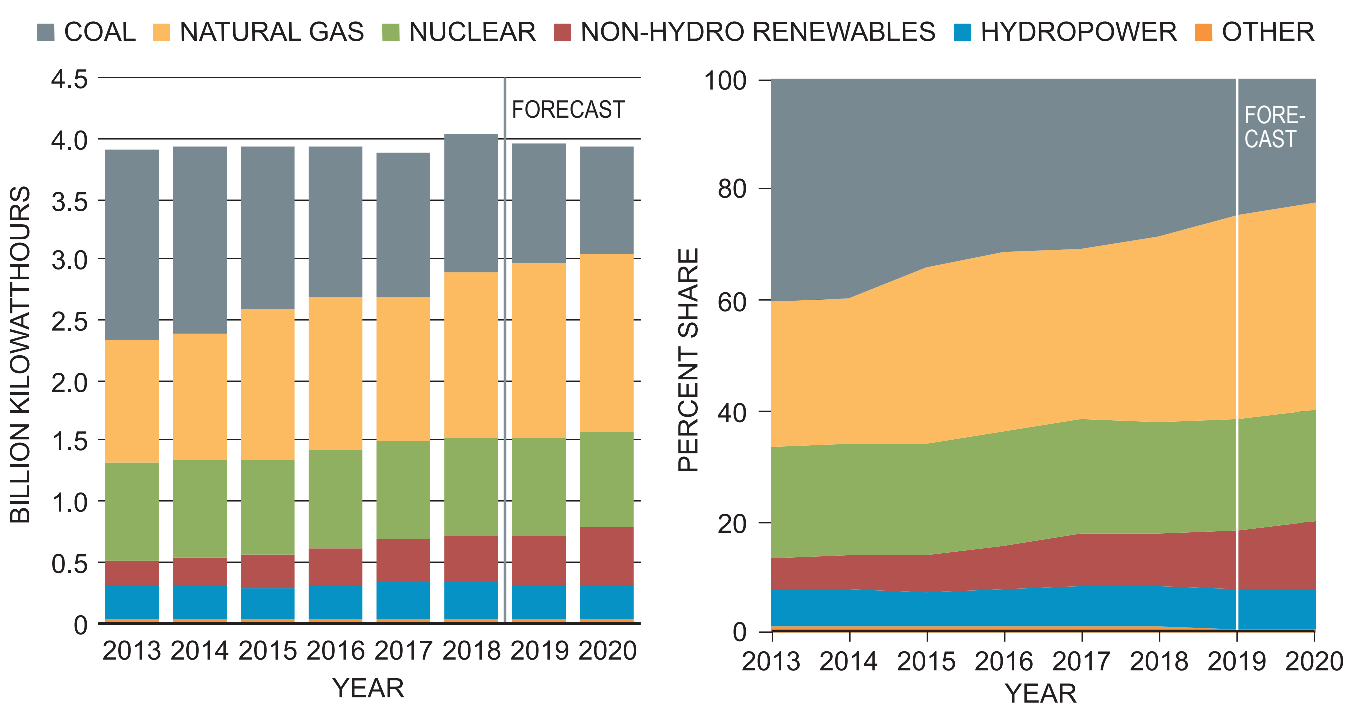
Source: EIA, *Monthly Energy Review*, August 2018.

Figure 2-85. *Electric Generation CO_2 Savings from Fuel Mix Changes Since 2005*



Source: PennWell, with data from MAPSearch and EIA 860 Report.

Figure 2-86. U.S. Power Plant Retirements, 2013 to 2022



Note: Labels show percentage share of total generation provided by coal and natural gas.
Source: EIA, Short-Term Energy Outlook 2019.

Figure 2-87. U.S. Electricity Generation by Fuel

e. Grid Stability

Power grids must remain stable to avoid major potential economic and human impacts. Economic impacts could range from industrial upsets due to unplanned trips to equipment damage. In the extreme, grid blackouts can cause potential impacts to safety, economic loss to communities, and diminished quality of life.

Frequency (or spinning speed) is the most critical factor for maintaining grid stability. Power grids can be thought of as a very large machine. While the wires are not actually spinning, generators and motors that are connected to the grid are spinning. This grid spinning speed, or frequency, should be 3,600 rpm or 60 hertz.

Solar and wind have attributes that must be addressed by grid operators to ensure stable grid frequency: their variability, their limited ramp-up capability, and their lack of grid-connected momentum (aka inertia). Inertia can be thought of as a rotating mass on a shaft. Without sufficient inertia connected to the grid, frequency and stability would rapidly decay if an unplanned loss of power generation occurs.

Natural gas technologies boast higher inertia values per MW across all generation technologies and faster ramp and start-up rates, than most, if not all, other conventional technologies. Gas provides two times the grid inertia of coal, it can ramp up three to four times faster, and be started up in minutes instead of hours.

Natural gas provides strong grid reinforcement and stability. In conjunction with renewables, natural gas provides a cost-effective, reliable supply of power.

f. Decarbonizing Options — Natural Gas and Power

Based on technology available today, system cost rises as energy systems move toward renewables. In the immediate term, the most effective and typically lowest-cost option to reduce greenhouse gas emissions and improve air quality is replacing coal with natural gas in power generation.

g. Power Sector Fuel Choice Analysis

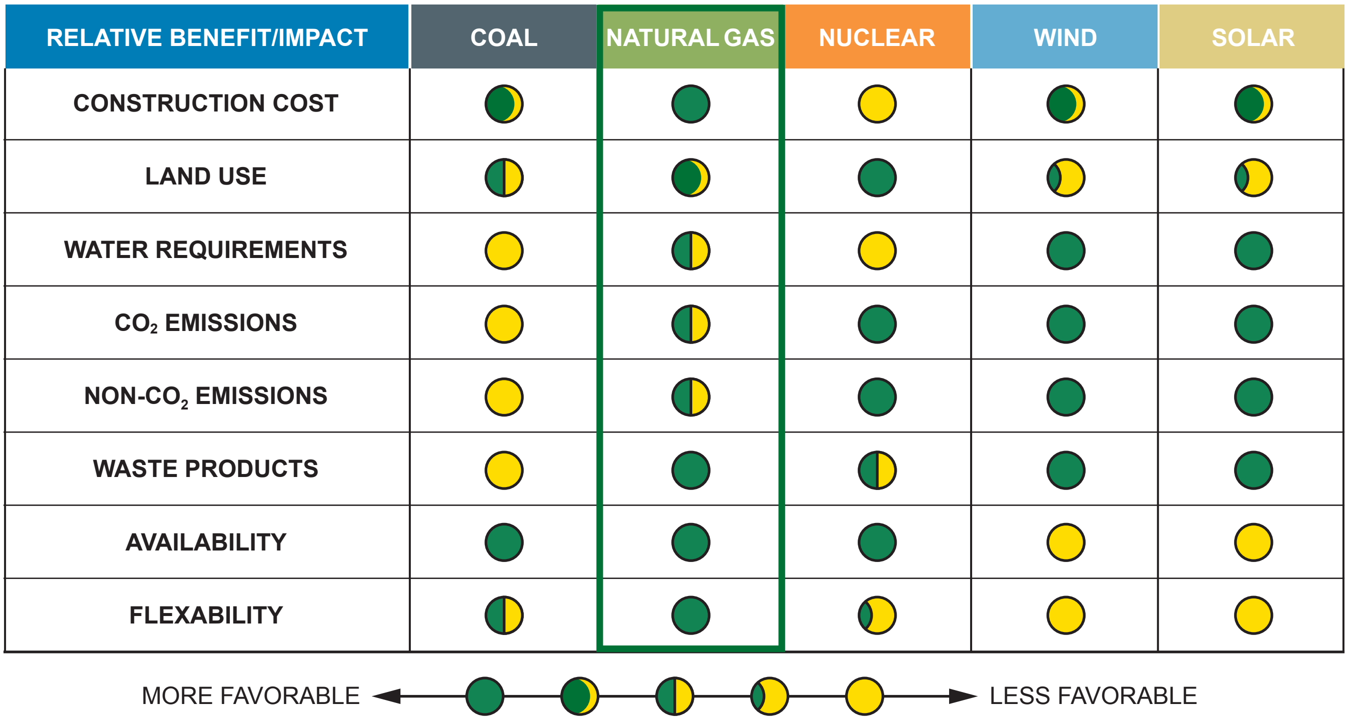
For power companies, a key issue is what fuels make the most sense to generate power. They have a wide range of factors to consider, as laid out in Figure 2-88. The major fuel choices are listed across the top of the chart: coal, natural gas, nuclear, wind, and solar. The rows list the various performance attributes for each, with full green being the best and full yellow less favorable.

In the public debate regarding energy, too often these attributes are considered in isolation, with attention paid only to cost or to emissions, for example. But, practically speaking, decisions such as these are made in combination, not isolation. Weighing tradeoffs is essential to making workable, viable, and responsible energy decisions.

When measured by cost, coal and gas are typically the most competitive fuels. Nuclear is expensive and mostly limited by regulatory and social acceptance, with many countries still outright banning or shutting down nuclear plants.

Evaluated on the metric of emissions, renewables outperform other fuels. But the electricity renewables produce costs more. The key question is how much policy makers are willing to mandate these higher-cost sources to reduce emissions, which will mean higher electricity prices for consumers. Gas-fired power has substantially fewer emissions of all types (CO_2, SOx, NOx, and particulate mattter) compared to coal, and can reduce CO_2 emissions by up to 60% compared to coal-fired plants.

Lastly, availability, because the wind is not always blowing and sun not always shining, renewables have a fundamental challenge for power companies who are responsible for providing adequate power every second of every hour. Wind often needs to be backed up nearly 100%. It is important to acknowledge that some regions of the United States are positioned better than others to utilize solar- and wind-fueled power. Gas-fired plants have high availability and the flexibility to ramp up and down to back-up intermittent wind and solar power. As described above, gas is much faster than coal in terms of responsiveness. While not addressd in detail in this study, the text box



Source: EPRI, Generation Technology Assessment.

Figure 2-88. *Power Generation Technology Assessment*

"Power Systems and Battery Storage" provides a brief summary the challenge of replacing natural gas with battery systems.

h. Summary

To facilitate the decarbonization of the electricity sector, usage of renewable electricity generation sources (e.g., wind, solar, hydro) will continue to increase. Addressing the intermittency issues of renewables will be critical to ensuring a reliable, resilient, and affordable power system while reducing CO_2 emissions. Viable, cost-effective options that partner with intermittent renewables are an essential component of the energy mix. Natural gas is reliable and efficient for baseload electricity generation. Its flexibility also makes it well suited to meet peak demand and back-up intermittent renewables. Therefore, natural gas can enable the broader penetration of renewables.

2. Natural Gas Infrastructure and the U.S. LNG Export Market

As described above, natural gas demand is expected to continue rising with reliable, abundant, low-cost supply of domestic energy available and increased LNG exports to global markets. The LNG value chain is complex and capital intensive, starting from the site of natural gas production to the end consumer as described below (see Figure 2-89 for graphic representation of the value chain):

Natural Gas Production

- Natural gas is produced from subsurface or subsea gas reservoirs reached through drilling.
- Natural gas is piped from the reservoirs to an onshore treatment plant where impurities and liquids are removed.

LNG Liquefaction Train

- Gas is condensed into a liquid at atmospheric pressure by cooling it to -260°F (-162°C).
- Gas in liquefied form (LNG) takes up about 1/600th less space than in a gaseous form.
- LNG is then stored at subzero temperatures in insulated tanks until it is loaded onto LNG carriers.

POWER SYSTEMS AND BATTERY STORAGE

A range of small-scale electricity storage technologies, including batteries, are viable in short duration, low capacity applications. Absent unexpected breakthroughs, these technologies are unlikely to be cost effective for managing the longer period intermittency/output variability of renewables or the demand variation for heating/cooling and power.

Battery deployment has been increasing in a wide range of sectors: consumer electronics, transportation, and power generation. Application and cost-effectiveness are dependent on sector output power-level requirements and needed duration of supply.

Batteries must be charged by an electricity source (coal, gas, renewables, etc.) and are less than 100% efficient which makes them a net consumer of electricity, thereby increasing global energy demand. Identifying the external source of energy is critical to understanding the life cycle impact of increasing battery deployment.

Batteries' performance degrades over time and they require regular replacement (more regularly than natural gas power plants). Batteries are also not renewable. They must be manufactured, deployed, decommissioned and recycled or disposed of properly. The life cycle impacts of batteries should be considered when comparing to other technologies.

Battery technology developers and academia continue to seek long-term breakthroughs to overcome current performance and cost limitations for bulk energy storage.

The United States set a record for natural gas demand on January 1, 2018: 60 BCF of gas withdrawn that day.

- How many batteries would you need to meet the U.S. gas storage withdrawn on January 1, 2018?
- 60 BCF/D of gas consumed by gas power plants could produce 8.5 TWh of electricity in one day.
- The world's largest battery storage facility was commissioned in Australia (Hornsdale) in December 2017.
  - Facility sized for 100 MW and 129 MWh.
  - Estimated cost of $65 million assuming $500/KWh.
- 8.5 TWh of electricity storage would need about 66,000 battery facilities like the one in Australia.
- Total battery cost would be more than $4 trillion for the United States alone—more than 5 times' the global investment made in all power infrastructure in 2017.

Source: ExxonMobil.

Figure 2-89. *LNG Value Chain*

- LNG export terminals often comprise multiple liquefaction trains.

LNG Carriers

- LNG is shipped in specially designed, ocean-going LNG carriers. LNG carriers come in various sizes and employ different technologies, but all of them have containment systems that store LNG at atmospheric pressure while maintaining a temperature of at least -162°C.

Regasification Terminal

- LNG is unloaded from carriers and stored at subzero temperatures in insulated tanks.
- When needed, LNG is piped to regasification units where it is warmed to a point where it reverts back to its gaseous state for transport.
- There are different structural types of LNG terminals, including onshore, offshore gravity-based, and offshore floating.

Customer/Utility Company

- Gas is transferred via natural gas pipeline to serve a network of customers in industrial, commercial, and residential markets.

In the case of the domestic LNG terminals currently operating, under construction, or pending FERC approval, these multibillion-dollar investments require a number of infrastructure-specific features to offer cost-competitive natural gas to world markets:

- On-site storage
- Robust marine capabilities/access
- Access to pipelines with key interconnections to the larger grid.

Access to pipelines is key to LNG terminal developers.[88] These pipelines are the means by which a terminal will source feed gas with the lowest-cost supply. Access to multiple pipelines that transport gas from diverse producing basins and trading hubs offer long-term supply security.

As previously described, the majority of new LNG export terminals will be located on the Gulf Coast in Texas and Louisiana. Several new pipelines have already been announced to link gas supply from both the Permian Basin and Haynesville producing areas with these Gulf Coast terminals (Figure 2-90). From the Permian Basin, Kinder Morgan has announced the Permian Highway Express, which is designed to transport up to 2.1 BCF/D of natural gas through approximately 430 miles of 42" pipeline" from Waha (Pecos, Texas) to the U.S. Gulf Coast and Mexico markets. The project is expected to be in service in late 2020, pending regulatory approvals.[89] Tellurian has also announced the Permian Global Access Pipeline, which is expected to transport 2.0 BCF/D of natural gas via a 625 mile, 42" direct line from Waha to Gillis, Louisiana.[90] Midcoast Energy, Tellurian, Enable Midstream Partners, and Enterprise Products Partners have all proposed pipelines south from Haynesville.[91]

F. New Pipeline Projects

To accommodate increasing demand and production, new pipeline capacity must be added, which can be done by building a new pipeline, adding new lateral line, adding new compression facilities on an existing line, or laying a new looped pipeline in the same right-of-way. In the United States, the majority of these projects are initiated by individual pipeline companies as well as some LNG export terminal developers and need the approval of the various regulatory agencies.

88 "The Corpus Christi Liquefaction Project is positioned near some of the most prolific oil and natural gas-producing regions in the country. The Cheniere Corpus Christi 23-mile 48" pipeline connects the Corpus Christi LNG plant to several interstate and intrastate pipelines, giving the facility access to robust gas resources in Texas and the Gulf Coast. In addition, Cheniere has transport capacity on third-party pipelines under long-term agreements. Natural gas supply is purchased from producers and marketers on a short and long-term basis to form a balanced portfolio of natural gas feedstock." Cheniere, "Top 5 Global Supplier of LNG by 2020," https://www.cheniere.com/terminals/corpus-christi-project/ (accessed August 1, 2019).

89 Kinder Morgan, Permian Highway Pipeline Project, https://www.kindermorgan.com/pages/business/gas_pipelines/projects/php/ (accessed August 1, 2019).

90 Tellurian Inc, Tellurian Business Update, April 2019; https://ir.tellurianinc.com/presentations (accessed August 1, 2019).

91 RBN Energy, Easy Livin' — Enterprise's Lumberjack Pipeline to Expand Haynesville Gas Takeaway (May 1, 2019), https://rbnenergy.com/easy-livin-enterprise-lumberjack-pipeline-to-expand-haynesville-gas-takeaway (accessed August 1, 2019).

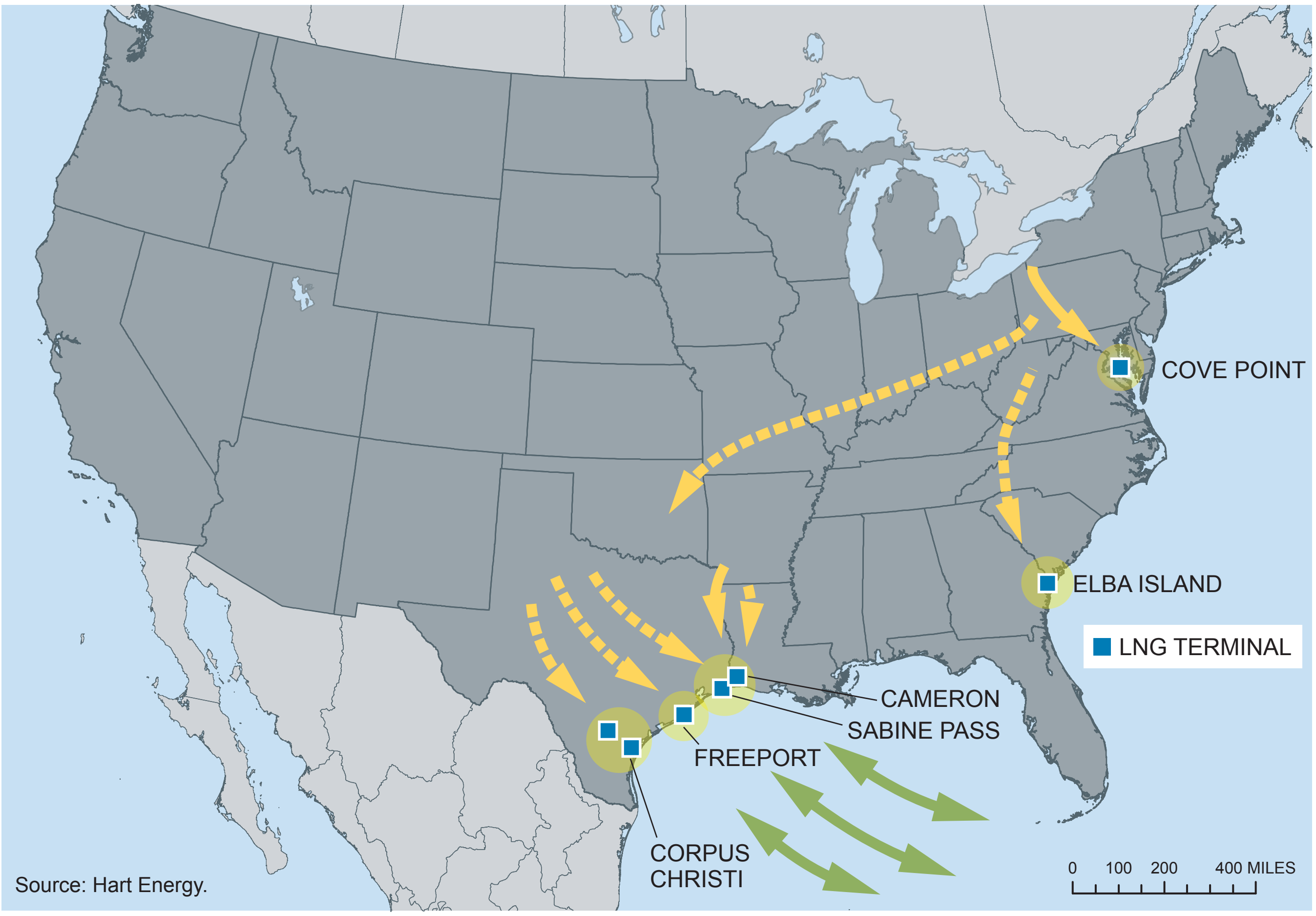


Figure 2-90. *LNG Export Terminals*

Historically, U.S. natural gas and power LDCs and utilities made the majority of pipeline transportation commitments to meet the needs of their customers. This made sense in a market where security of supply was a major concern. The market structure helped because LDCs/utilities could recover costs of supply and often get a return on those costs of supply. To increase the efficiency of the market, marketing companies stepped into the role of providing services to LDCs and utilities, often managing infrastructure on their behalf under asset management agreements. This has created value for all stakeholders.

Today, with the abundance of natural gas supply in the United States, the majority of new pipelines are underpinned by producers, especially those from the supply area to market locations where the demand side already has access to supply. This also leads to gas-on-gas competition as lower-cost supply reaches markets to compete with more expensive sources of supply.

Market fundamentals (i.e., supply, demand, and resulting prices) will continue to signal the need for the construction of new pipeline capacity. For example, a production company, which projects increasing supply volumes in an area of constrained pipeline capacity, may have a need to subscribe to new capacity as a means of avoiding pipeline transportation curtailments and negative impacts to flowing gas.

Similarly, an LDC with increasing customer demand may need to solicit development of new infrastructure capacity. In both supply and market area developments, a decision to contract for new pipeline capacity may need to be considered and effected prior to the existence of an explicit price signal in the market, as many projects require years to plan, permit, and construct. Delaying expansion activities until explicit price signals materialize may fail to provide capacity when it is actually needed.

Besides the projection of future supply/demand constraints, a more obvious signal for pipeline transmission system development is a sustained increase in price between different geographic locations. A price differential between any two points is referred to as a locational basis, or basis differential. Basis differentials may be higher or lower than a pipeline's maximum tariff rate, generally higher when capacity is fully utilized in an area or lower where surplus pipeline delivery capacity generally exists. The former, if sustained, may signal the need for new pipeline capacity and can create interest in pipeline expansions or new infrastructure construction.

Short-term basis differentials by themselves, however, are not a definitive signal of the need for infrastructure development. If there is excess supply available to a market, then market forces create pressure to reduce both the gas commodity cost and the price that shippers are willing to pay for transportation capacity (i.e., surplus). Given the seasonal nature of the gas market and the need to reliably serve winter peak demand, many pipeline systems are designed to have sustainable capacity above their average daily demand for much of the year. This results in short-term daily pricing for transportation capacity that may be the pipeline's maximum tariff rate for much of the year. Thus a basis differential that exists for a sustained period of time is more reflective of the value of long-term capacity contracts and is a better barometer for infrastructure investment decisions.

1. Unexpected Delays

It is a commercial challenge to aggregate several suppliers together to get critical mass to underpin a new project. This can delay new project development. In addition to securing sufficient firm or long-term shipping commitments, pipeline developers must navigate the permitting and siting process prior to initiating construction.

From initiation of a project to start-up, a new pipeline project could take 3 to 5 years. In the construction phase, the pipeline company may incur higher costs than the estimate submitted and approved by the regulatory authority. Higher than estimated costs could arise if the project faces opposition or requires a change in route. Higher costs are typically covered from the pipeline company's return margin. If the additional costs rise substantially, then the company may abandon the pipeline project entirely.

Another layer of complexity is nonstakeholder control over interstate pipeline construction to connect supply and demand can be unpredictable and disruptive (e.g., Constitution, Atlantic Coast).

2. Pace of Development Critical to Growth and Benefits U.S. Consumers/Economy

Given the transportation limitations of natural gas, the growth in domestic supply and demand, combined with the expected changes to gas flow patterns, new infrastructure development and continued investment in supply development are key. Developing the infrastructure that transports natural gas to end users, both domestically and globally, and ensuring access to this infrastructure are both necessary to enable continued investment in supply and gas market growth.

After the various market signals discussed above make it clear that a new pipeline is needed, the pipeline developer/owner must navigate the regulatory process to propose and earn approval of its project. This process, described in detail in Chapter Three, "Permitting, Siting, and Community Engagement for Infrastructure Development," comprises state and federal regulatory requirements. Neighboring communities and nongovernmental organizations are additional stakeholders in new natural gas infrastructure projects.

Any delays caused by changes in the applicable permitting processes or regulatory framework or due to other challenges raised by other stakeholders place such projects at risk.

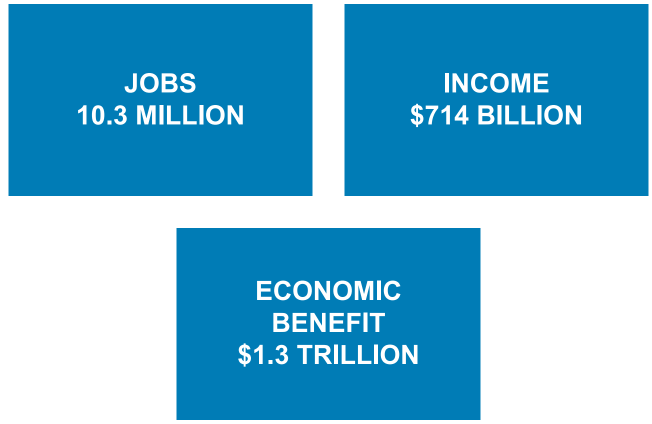
V. THE VALUE OF INFRASTRUCTURE

The value of infrastructure is well-documented across all sectors. A 2018 study by the Congressional Research Service stated that "infrastructure is understood to be a critical factor in the health and wealth of a country, enabling private business and individuals to produce goods and services more efficiently."[92] Economic systems and infrastructure are closely connected and highly dependent on the other to properly function. Just as robust infrastructure can be an enabler of strong economic activity, poor infrastructure can hinder economies from reaching their full potential. Economies with weak infrastructure are known to be at a structural disadvantage to economies where adequately funded infrastructure investment positively impacts growth and productivity.[93]

These principles that apply to broad economies also apply to individual sectors. In the energy sector, midstream infrastructure provides a wide array of benefits to stakeholders throughout the energy value chain and to the U.S. and global economies, both directly to energy providers and to consumers and businesses that depend on reliable, affordable energy.

By enabling the energy sector to function efficiently and cost-effectively, midstream infrastructure supports the overall oil and gas sector, which is responsible for $1.3 trillion, or 7.6%, of U.S. gross domestic product (GDP), 10.3 million direct, indirect, and induced American jobs, and $714 billion in labor income in 2015 (Figure 2-91).[94] This economic impact is a result of wages, taxes, capital investments, and support to other industries. These benefits extend far beyond traditional natural gas and oil producing states. Recent research shows measurable economic benefits in all 50 states and the District of Columbia.[95]

The importance of the energy sector to the broader economy can be seen at the industry level. For example, fuel oils, gasoline, and crude petroleum represented 46% of the total weight and 43%



Source: PWC.

Figure 2-91. *Economic Contributions of Oil and Natural Gas to the U.S. Economy*

of the total value of all commodities shipped by water in 2017.[96]

The economic value specific to midstream infrastructure generally fall into five categories that are:

1. *Economic growth:* Includes the direct economic activity resulting from infrastructure investment, and the indirect and induced effects on supply chains and ancillary industries as infrastructure construction and operating companies increase their demand for goods and services.
2. *Job creation:* Similar to the economic growth impacts, there are direct, indirect, and induced jobs created from the construction and operation of midstream infrastructure.
3. *Increased exports:* Infrastructure investment supports higher domestic energy production, which in turn has made the United States a major exporter of energy products in particular.
4. *Improved manufacturing competitiveness:* Reliable energy infrastructure has supported growing U.S. energy production, which has lowered costs for domestic manufacturers, particularly those that are energy-intensive

92 Stupak, Jeffrey M., "Economic Impact of Infrastructure Investment," January 24, 2018, Congressional Research Service, https://fas.org/sgp/crs/misc/R44896.pdf (accessed October 1, 2019).

93 Srinivasu, B. and Srinivasa Rao, P., "Infrastructure Development and Economic Growth: Prospects and Perspective," *Journal of Business Management & Social Sciences Research*, Volume 2, No. 1, January 2013, https://pdfs.semanticscholar.org/8fcd/6cb961185007b6f929473a716fe588c0ff86.pdf (accessed October 1, 2019).

94 PricewaterhouseCoopers, "Impacts of the Oil and Natural Gas Industry on the US Economy in 2015," July 2017, https://www.api.org/news-policy-and-issues/american-jobs/economic-impacts-of-oil-and-natural-gas (accessed October 1, 2019).

95 Ibid.

96 Bureau of Transportation Statistics, Freight Analysis Framework, https://www.bts.gov/archive/subject_areas/freight_transportation/faf/users_guide/ (analyzed based on "Total Flows" and accessed on November 22, 2019).

or use energy products as feedstock. The increase in U.S. manufacturing competitiveness has led to increased investment and job creation in addition to the benefits mentioned in the first two points listed above.

5. *Market efficiency benefits to households:* More efficient transport of energy lowers costs to consumers, reducing energy bills and increasing their disposable income for other goods and services.

A. Economic Growth

Infrastructure investment has a direct impact on economic growth and so-called "multiplier effects" as the initial capital outlay ripples through the economy.

- Direct effects are the initial investment, for example payments to construction companies to lay new pipeline.
- Indirect effects capture the supply chain effects (e.g., domestic steel purchased to make pipelines).
- Induced effects represent impacts on local industries due to rising consumer expenditures (e.g., a pipeline construction worker spends more on food, clothing, and other goods and services).

Several studies over the past 5 years have estimated the total economic impacts of midstream infrastructure investment. Including the direct, indirect, and induced impacts, the estimates vary from $31 billion to $75 billion in annual economic growth boosting local, state, and national economic activity. In addition, other studies have estimated $70 to $100 billion dollars in GDP growth.

Looking forward, forecasts for U.S. oil and natural gas production growth will require considerable investments in midstream infrastructure. A recent study by ICF on behalf of the Interstate Natural Gas Association of America estimates a need for $685 to $898 billion in energy infrastructure spending through 2035 in the United States and Canada.[97] ICF's economic impact analysis suggests this would add $1.3 trillion to U.S. and Canadian GDP between 2018 and 2035, or about $70 billion annually. The study projected that for the United States alone, pipeline and gathering infrastructure spending would contribute more than $565 billion to U.S. GDP, $106 billion in federal taxes, and $91 billion in state and local taxes over the 2018 to 2035 study period. On an annual basis, this averages to $31 billion in U.S. GDP, $6 billion in federal tax revenue, and $5 billion in state and local taxes.

There have been several reports estimating the amount of infrastructure needed to address the increase and geographic shift in supply basins in the United States. In 2017, ICF undertook a study on behalf of API (the ICF Study), that investigates the amount of oil and natural gas infrastructure development possible in the United States through 2035.[98] Assuming oil production ranges from 9 to 12 MMB/D, the study finds that 3 to 5 MMB/D of new and or repurposed capacity will be needed. To support America's supply growth, the construction of the vast majority of the new oil pipeline transport that is projected for the United States needs to be completed during the next 5 to 10 years.

The ICF Study also indicates that assuming natural gas production grows from 110 to 131 BCF/D, between 49 and 68 BCF/D of new pipeline capacity will be needed to support the levels of production and market growth that are projected. The incremental transport of 2.6 to 3.6 BCF/D per year would be added to an already extensive gas transportation network that currently provides roughly 150 BCF/D increasing at roughly 2% per year. Additionally, for transport of NGLs, between 1.8 and 2.6 MMB/D of new pipeline capacity will be needed to support the levels of production and market growth that are projected through 2035. According to the ICF Study, total capital expenditures for oil and natural gas infrastructure development will range from $1.06 to $1.34 trillion from 2017 through 2035. These levels of investment equate to an average annual capital investment ranging from $56 to $71 billion. This includes investments in new as well as existing infrastructure.

97 Interstate Natural Gas Association of America Foundation, Reports, June 18, 2018 release, North American Midstream Infrastructure through 2035.

98 ICF International, Inc., "U.S. Oil and Gas Infrastructure Investment through 2035," 2019, https://www.icf.com/resources/reports-and-research/2017/us-oil-and-gas-infrastructure-investment-through-2035.

This infrastructure development will continue to have significant and widespread impacts on the U.S. economy from 2017 to 2035, adding an annual average of $79 to $100 billion to U.S. GDP. In addition, federal taxes and states taxes over the 2017 to 2035 timeframe are estimated to exceed $500 billion.

B. Job Creation

Similar to the economic impacts, the construction and operation of midstream infrastructure generates direct, indirect, and induced employment. ICF estimates that annual midstream infrastructure (pipeline and gathering) spending of $22 billion per year, will generate more than 325,000 U.S. jobs per year.[99] This estimate, while substantial, does not include jobs related to operating and maintaining oil and natural gas infrastructure, which would add to the total employment impact. Approximately one-third, or 108,000 jobs, would be directly involved in infrastructure development. The remaining two-thirds, or 217,000 workers, would be employed in indirect and induced jobs. ICF also projects total direct, indirect, and induced employment per year of 725,000 in the United States and Canada based on the estimated total oil and natural gas infrastructure investment of $38 to $50 billion annually.

The expansion of infrastructure spending from 2013 to 2017 has boosted jobs and local economies; this is set to continue over the coming decade and perhaps beyond. While the employment benefits are not quite at the same level as they were (given capex has taken a slight step lower), it is still a meaningful contributor to jobs.

The number of jobs predicted are directly linked to the regions that are impacted by new supply basins or exports. Looking ahead, the states of Texas and Louisiana stand out with about 35% of the total U.S. projections. In addition, Pennsylvania, Ohio, New Mexico, California, and New York are other states that stand to benefit.

However, as the energy sector market expands and increases in jobs are predicted, an acute skilled labor shortage is taking a toll on the oil and natural gas sector. Building and maintaining America's more than 2.5 million miles of pipelines requires a diverse army of highly trained and skilled career professionals.

Eagle Ford Consortium, a nonprofit encouraging the development of the Eagle Ford shale oil field, recently stated that the worker shortage has hampered the ability to build new projects, pointing to a proposed $10 billion steam cracker plant. Worker shortage continues to affect project costs and cause delays. Labor issues are plaguing the Texas energy industry in the Permian Basin, where an estimated 15,000 jobs are found vacant at any given time. Oil executives fear that the acute shortage could hinder the industry for decades to come.[100]

In the Permian Basin, the most active drilling area in the country, labor market conditions "continue to be bumpy," even with increases in crude oil production, according to the Federal Reserve Bank of Dallas.[101]

Chapter 3, "Permitting, Siting, and Community Engagement," further describes this growing trend of labor shortage amid the industry's growth and makes several recommendations to improve access to education, training, and other pathways to formal jobs in the oil and natural gas industry.[102]

C. Stronger Exports

Stronger domestic energy production, supported by efficient transportation of energy products, has helped to boost U.S. energy exports and reduce the energy trade balance. EIA reports that during the past decade, the U.S. trade gap for energy products has narrowed: from 2003 to 2007, the value of energy imports was about 10 times greater than the value of exports, and by 2017, imports were about 1.5 times greater than exports, based

99 Interstate Natural Gas Association of America Foundation, Reports, June 18, 2018 release, North American Midstream Infrastructure through 2035.

100 Accenture Strategy, "The Talent Well Has Run Dry," 2017, https://www.accenture.com/t20170630T025458__w__/us-en/_acnmedia/PDF-55/Accenture-Strategy-Talent-Well-Oil-Gas.pdf (accessed November 6, 2019).

101 Davis, C., "U.S. Energy Sector Market Improving, but Labor Shortage Taking a Toll," *NGI's Shale Daily*, January 10, 2017, https://www.naturalgasintel.com/articles/108991-us-energy-sector-market-improving-but-labor-shortage-taking-a-toll.

102 Refer to Section III.C.3, Economic Interests and Skilled Labor Needs, in Chapter 3 of this report.

on data from the U.S. Census Bureau.[103] This paradigm shift in U.S. net energy trade has had large impacts on the country's overall trade deficit. Specifically, EIA calculates that the total U.S. merchandise trade deficit in 2017 was nearly $250 billion lower than it otherwise would have been if the petroleum (crude oil, refined products, and NGLs) trade deficit had remained at its 2007 level (Figure 2-92).[104] In 2018, oil imports accounted for only 6.1% of the U.S. trade deficit, the lowest level in more than 25 years.

Further development of midstream infrastructure will continue to support growth in the export of piped gas to Mexico, LNG, U.S. petrochemicals, refined product, and NGLs. The EIA predicts that the United States will become a net exporter of oil by the end of 2020, sending abroad 1.2 MMB/D more than it imports, compared to a deficit of 9.4 MMB/D a decade ago. That deficit is falling due to shale production. The surplus of refined product exports will continue to grow to about 5 MMB/D, resulting in an overall net oil trade surplus. This interplay of crude oil trade, refining, and product trade requires a robust and efficient supply chain supported by modern infrastructure to position the United States with a competitive cost of supply in a global market.

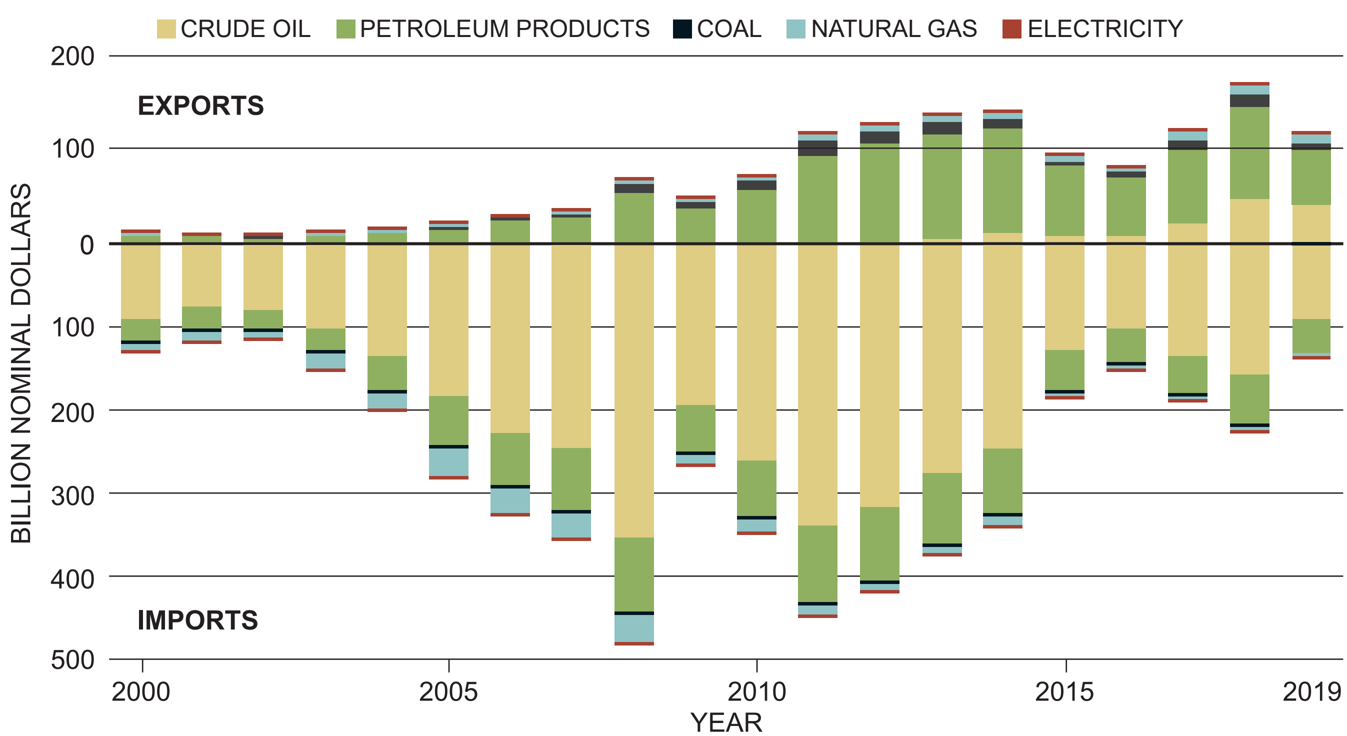
103 U.S. Energy Information Administration, "The changing U.S. energy trade balance is still dominated by crude oil imports," *Today in Energy*, October 16, 2018, https://www.eia.gov/todayinenergy/detail.php?id=37253.

104 World Oil, "U.S. Shale Boom Lowered Trade Defect by $250 Billion," November 14, 2018, https://www.worldoil.com/news/2018/11/14/us-shale-boom-lowered-trade-deficit-by-250-billion.

D. Improved Manufacturing Competitiveness

America's increase in energy production has been a major contributor to an increase in domestic manufacturing activity. The lowering of input and feedstock costs has spurred investment into the petrochemical and other energy-intensive industries. A 2015 study by the Harvard Business School and Boston Consulting Group found that:

> America's abundant and low-cost unconventional gas and natural oil resources are a once-in-a-generation opportunity to



Source: EIA, *Today in Energy*, October 16, 2018, based on U.S. Census Bureau Export and Import Data.

Figure 2-92. *U.S. Trade in Crude Oil, Petroleum Products, Natural Gas, and Coal, 2000-2019* change the nation's economic and energy trajectory. The United States now has a global energy advantage, with wholesale natural gas prices averaging about one-third of those in most other industrial countries, and industrial electricity prices 30% to 50% lower than in other major export nations. That means major benefits for industry, households, governments, and communities, while reducing America's trade deficit and geopolitical risks. The United States has had a 10- to 15-year head start in commercializing unconventional resources versus other countries. Though the recent decline in world oil prices has affected the short-term prospects of U.S. unconventionals, low prices are unlikely to reduce the fundamental U.S. competitive advantage over the next several decades.[105]

The U.S. industrial sector used 32.5 quadrillion BTUs of energy in 2018 from a variety of sources including natural gas, petroleum, electricity, renewables, and coal.[106] In addition to other factors (e.g., regulatory environment, tax policy, health care costs, and workforce quality) infrastructure and access to reliable, affordable energy are important dimensions in the competitiveness of U.S. manufacturers. Since U.S. shale oil and natural gas production ramped up production in the late 2000s, production costs for energy-intensive industries such as chemicals, metals, food, and refining have been reduced as a result of the increase in natural gas supply.[107] Validating this point, the Federal Reserve Bank of Boston found evidence that the boom in U.S. energy production—which lowered domestic energy prices—improved the competitiveness of energy-intensive sectors.[108]

In a 2019 follow up to the 2013 report on the impact of shale gas, the American Chemistry Council indicated "After years of high and volatile natural gas prices, new domestic supplies of more affordable natural gas and NGLs have created a competitive advantage for U.S. chemical manufacturing, leading to industry growth and new jobs. Companies from around the world are investing in new projects to build or expand their shale advantaged capacity in the United States. Since 2010, 334 projects cumulatively valued at $204 billion have been announced, with 53% of the capital investment completed or under construction, 40% in the planning phase, and 7% of delayed or unknown status"[109]

As referenced in Figure 2-93 and Table 2-1, low-cost gas and gas-fired power, particularly, benefit energy-intensive industries, which use gas and high levels of electricity to fuel foundries, paper mills, and other heavy industrial processes. Boston Consulting Group's *Made in America, Again* series estimated the cost savings from unconventional natural gas to be 4% or more of total manufacturing costs in a variety of industries, including minerals, metals, paper, and textiles.

As shown in Table 2-1, economic contributions from the chemical industry investments linked to shale in the U.S. are immense. From 2010 through May 2019, 334 projects totaled $204 billion in cumulative value. Projects through 2025 are estimated to have a $292.2 billion impact on economic output and generate nearly 800,000 jobs and $57.2 billion in payroll income.

However, a 2018 study by Boston Consulting Group showed that the gains in competitiveness from the U.S. energy revolution are narrowing as

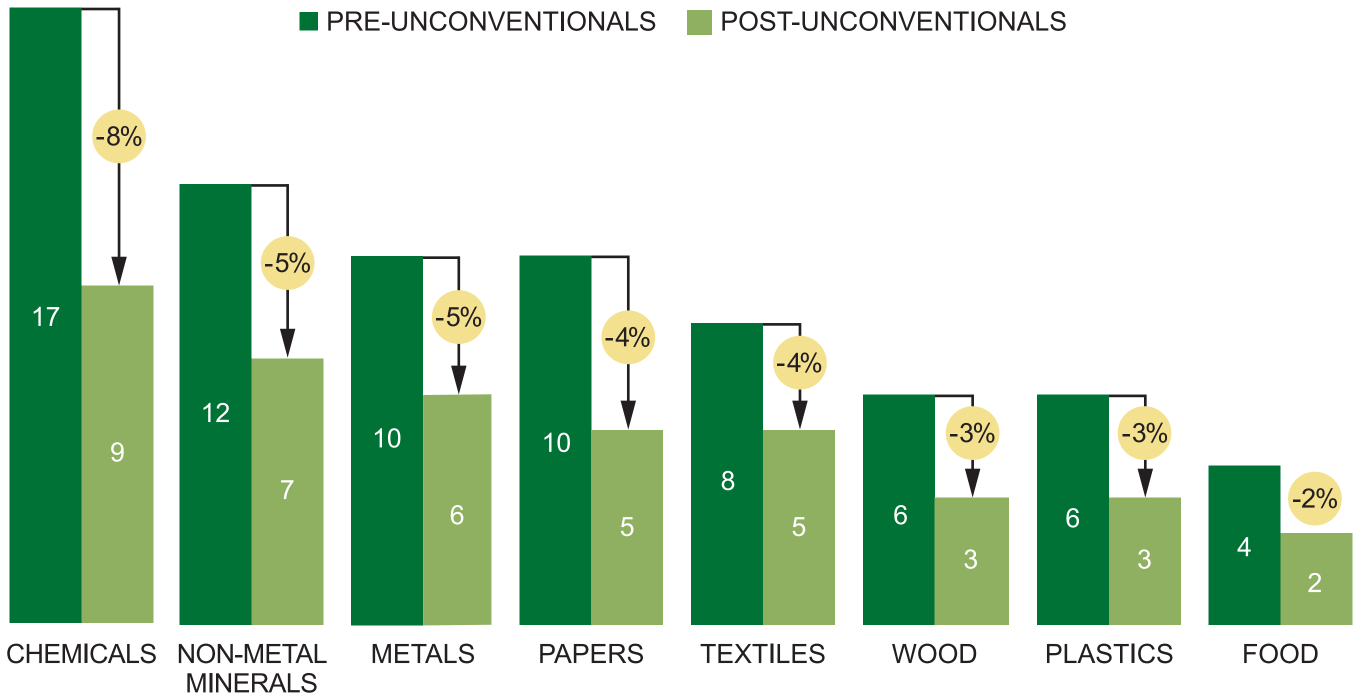
105 Porter, M. E., Gee, D. S., and Pope, G. J., *America's Unconventional Energy Opportunity,* Harvard Business School and Boston Consulting Group, June 2015, https://www.hbs.edu/competitiveness/Documents/america-unconventional-energy-opportunity.pdf.

106 U.S. Energy Information Administration, *Monthly Energy Review,* October 2019, https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf).

107 IHS Economics, *The Economics Benefits of Natural Gas Pipeline Development on the Manufacturing Segment,* prepared for the National Association of Manufacturers, May 2016, https://www.nam.org/wp-content/uploads/2019/05/NAM_NG_Report_042816.pdf.

108 Federal Reserve Bank of Boston, "The Competitiveness of U.S. Manufacturing," Current Policy Perspectives, no. 2014-3, 2014.

109 American Chemistry Council, "U.S. Chemical Investment Linked to Shale Gas: $204 Billion and Counting," May 2019, Shale Gas Fact Sheet, https://www.americanchemistry.com/Policy/Energy/Shale-Gas/Fact-Sheet-US-Chemical-Investment-Linked-to-Shale-Gas.pdf.



Source: M. E. Porter, D. S. Gee, and G. J. Pope, *America's Unconventional Energy Opportunity,* Harvard Business School & Boston Consulting Group, June 2015, https://www.hbs.edu/competitiveness/Documents/america-unconventional-energyopportunity.pdf.

Figure 2-93. *Natural Gas and Electricity Costs as a Percentage of Total Pre-Unconventionals Manufacturing Costs*

From Higher Chemical Industry Output, 2010 to 2025 (Permanent)			
	Jobs	**Payroll ($ billion)**	**Output ($ billion)**
Direct	79,251	$9.7	$106.2
Indirect	351,585	$29.2	$127.7
Payroll-Induced	354,948	$18.3	$58.3
TOTAL	785,784	$57.2	$292.2

Source: American Chemistry Council, Shale Gas Fact Sheet, May 2019.

Table 2-1. *Economic Contribution from Chemical Industry Investments*

other countries catch up.[110] The EIA's Manufacturing Energy Consumption Survey indicates that the U.S. manufacturing sector's ability to switch fuels has steadily declined since the mid-1990s. The latest survey from 2014, published in September 2018, shows that 90% of the manufacturing sector's energy consumption is unswitchable.[111] In other words, U.S. manufacturers have very limited ability to switch energy sources in response to relative price differentials, shortages, or other issues. This lack of flexibility underscores the need for reliable energy supply and robust infrastructure to efficiently deliver low-cost energy.

E. Market Efficiency Benefits to Households and Businesses

The benefits described above are enabled by robust, efficient, and adaptable infrastructure that ensures the transportation of commodities to markets, both domestic and abroad. The ability to utilize infrastructure to align supply to customer demand has resulted in restrained prices of electricity and growth in the domestic manufacturing industry. Development of U.S.

110 Boston Consulting Group, "How Shifting Costs are Altering the Math of Global Manufacturing," December 2018, https://www.bcg.com/publications/2018/how-shifting-costs-are-altering-math-global-manufacturing.aspx.

111 U.S. Energy Information Administration, 2014 Manufacturing Energy Consumption Survey, 2018, https://www.eia.gov/consumption/manufacturing/index.php (accessed November 7, 2019).

energy infrastructure to support the growth in oil and natural gas production also improves access to energy supply, increases market efficiency, lowers prices for households and businesses, and makes U.S. manufacturers more competitive internationally.

> "The ability to transport energy at lower costs and connect supply and demand centers creates more efficient markets and lower prices for consumers. Indeed, the large-scale buildout of energy infrastructure over the last few years has been a direct response to increasing demand and the need to alleviate infrastructure constraints across hydrocarbons."[112]

The energy industry also benefits from lower feedstocks, ranging simply from the cost of electricity to cheaper inputs for the plastics/chemicals industries. The broader economy, specific to infrastructure, has benefited from greater spending on projects that have directly and indirectly employed a large workforce and contributed to gross investment as well as government tax revenue. As an example, in 2012, Dow Chemical announced plans to build a 1.5 million tonne/year ethylene plant at its operations in Texas and to restart an ethylene plant in Louisiana indicating that the lower price outlook for U.S. gas stimulated its decision to invest $4 billion to expand.

As oil and natural gas production has risen steeply over the past decade, energy infrastructure companies have increased capital spending to meet the need for new transportation, storage, and processing assets."[113] Midstream infrastructure positively impacts the economy and energy markets in multiple ways. Capital investments directly benefit construction companies, workers, and local communities. They also indirectly benefit businesses throughout the supply chain that provide inputs into infrastructure projects. In turn, increased economic activity and employment bolsters tax revenue and provides opportunities to strengthen public services.

112 Laitkep, M., "After Years of Growth, Is Midstream Capex Peaking?" Alerian, May 7, 2019.

113 Ibid.

F. U.S. Energy Prices and Expenditures

Domestic natural gas prices have decreased due to increased natural gas supply, delivering tangible results for the American family (Figure 2-94). Various studies indicate an increase in disposable income from $800 to $2,500 annually. This additional income would be extremely beneficial for low-income households that typically spend 10% to 20% of their total income on monthly energy expenses.

EIA indicates that U.S. total energy expenditures, which is the amount of money spent to consume energy in the United States expressed as a percent of GDP, has decreased each year since 2011, leading to the record low energy expenditure share of 5.6% in 2016.[114]

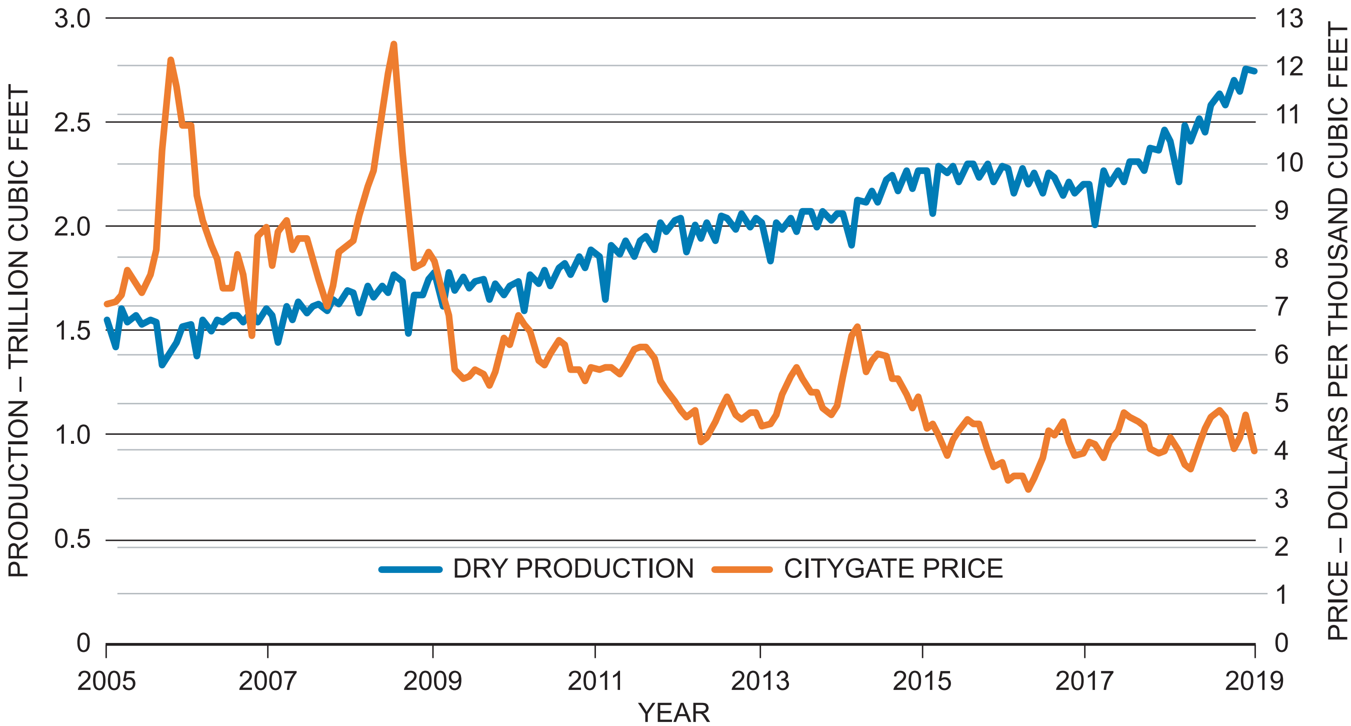
The decrease in 2016 was entirely attributable to lower energy prices, as total energy consumption had remained virtually unchanged since 2013. The U.S. average energy price was $15.92 per million BTU in 2016, down 9% from 2015, and the lowest since 2003, when adjusted for inflation. Average energy prices reached their highest point on record in 2008, when they averaged $24.13 per million BTU.

Over the last decade the price of natural gas delivered to U.S. residential customers has either stayed flat or declined, as shown in Figure 2-95.

In 2017, U.S. energy expenditures per GDP reached 5.8%, up from the record low of 5.6% in 2016, after its first annual increase since 2011. These increases are primarily a result of increased average U.S. energy prices, up almost 9% nationally from 2016 to 2017. Average U.S. prices for petroleum and natural gas increased by 14% and 13%, respectively, and electricity prices increased by 2%.

Based on realized prices in 2017 and some months in 2018, EIA does not expect the downward energy price trend to continue, as average energy prices of natural gas, retail electricity, and

114 U.S. Energy Information Administration, "In 2016, U.S. energy expenditures per unit GDP were the lowest since at least 1970," *Today in Energy*, July 30, 2018, https://www.eia.gov/todayinenergy/detail.php?id=36754.



Source: EIA, *Natural Gas Monthly*, June 2019.

Figure 2-94. *U.S. Monthly Dry Natural Gas Production and Monthly Average Citygate Price, 2005-2019*

products such as motor gasoline have all increased since 2016, contributing to higher U.S. energy expenditures since that year.

However, as a trend, energy expenditure as a percentage of GDP has fallen from ~10% about 10 years ago to the 6% to 8% range in 2019. In addition, with abundant oil and natural gas, a return up to 10% seems unlikely near term.

G. Electricity

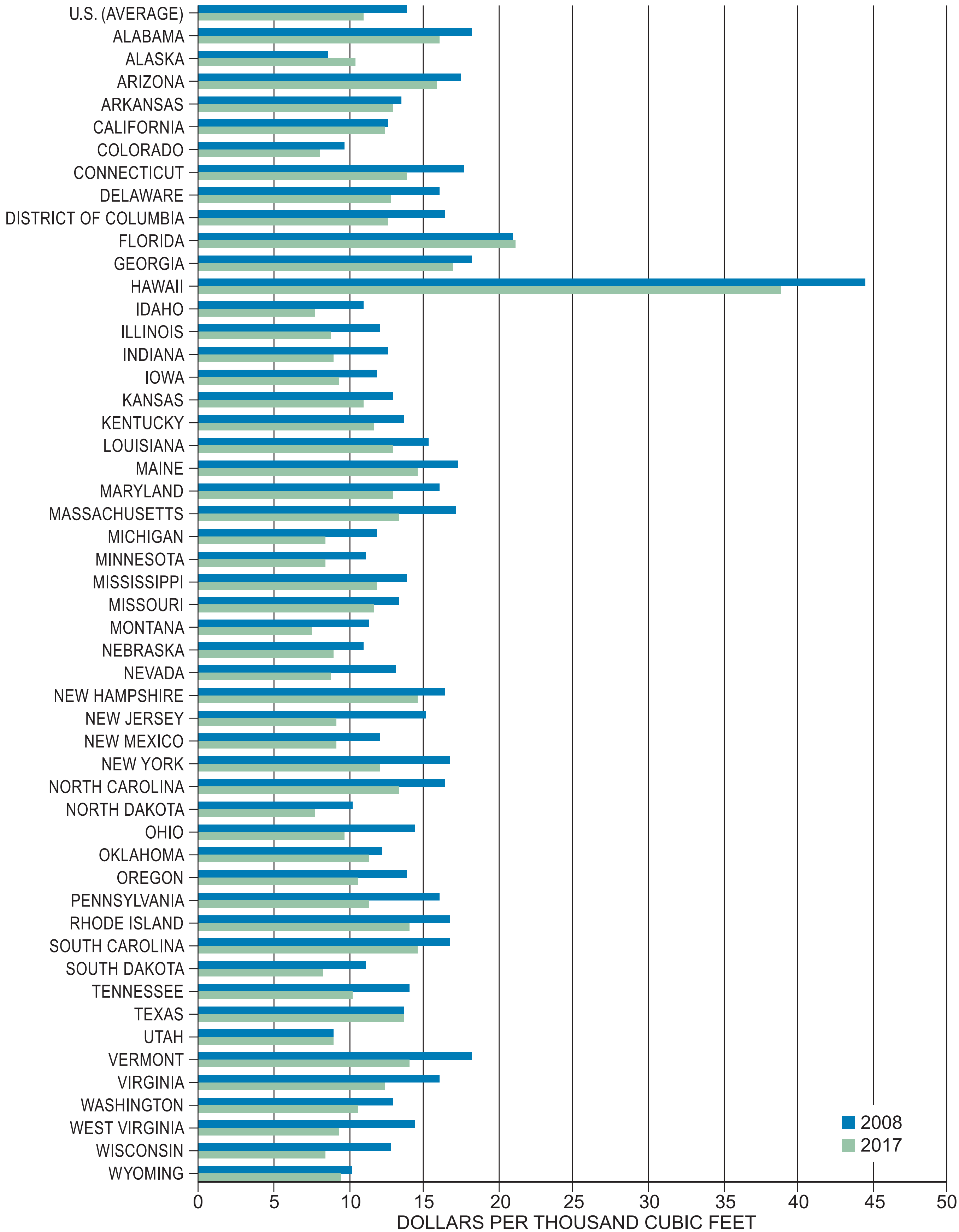
The trend in the price of electricity has also been critical to follow. Helped by the supply expansion of the last 10 years, many sectors of electricity consumption, such as the commercial, transportation and industrial sectors, have found prices flat to down and benefited from a cost perspective (Figure 2-96). Residential energy has been the one area to see an expansion, although this growth has plateaued to some degree in recent years.

Historically (Figure 2-96), in the period of 1980 to 2000, electricity prices steadily rose not just for residential use but for commercial, industrial, and transportation sectors. From an electricity perspective, the avergage price of electricity has grown, but between 2009 and 2018, the growth was limited to ~8%—well below growth trends of previous decades (Figure 2-97).

Evidence of market efficiency can be seen directly in price levels and differentials across geographies. For example, given the abundance of natural gas in the United States, the price of gas-generated electric power should be relatively low, and differentials across geographies should largely be a function of the cost of transportation. However, given infrastructure bottlenecks limiting the ability to move domestic gas throughout the New England, price differentials can be large (Figure 2-98).

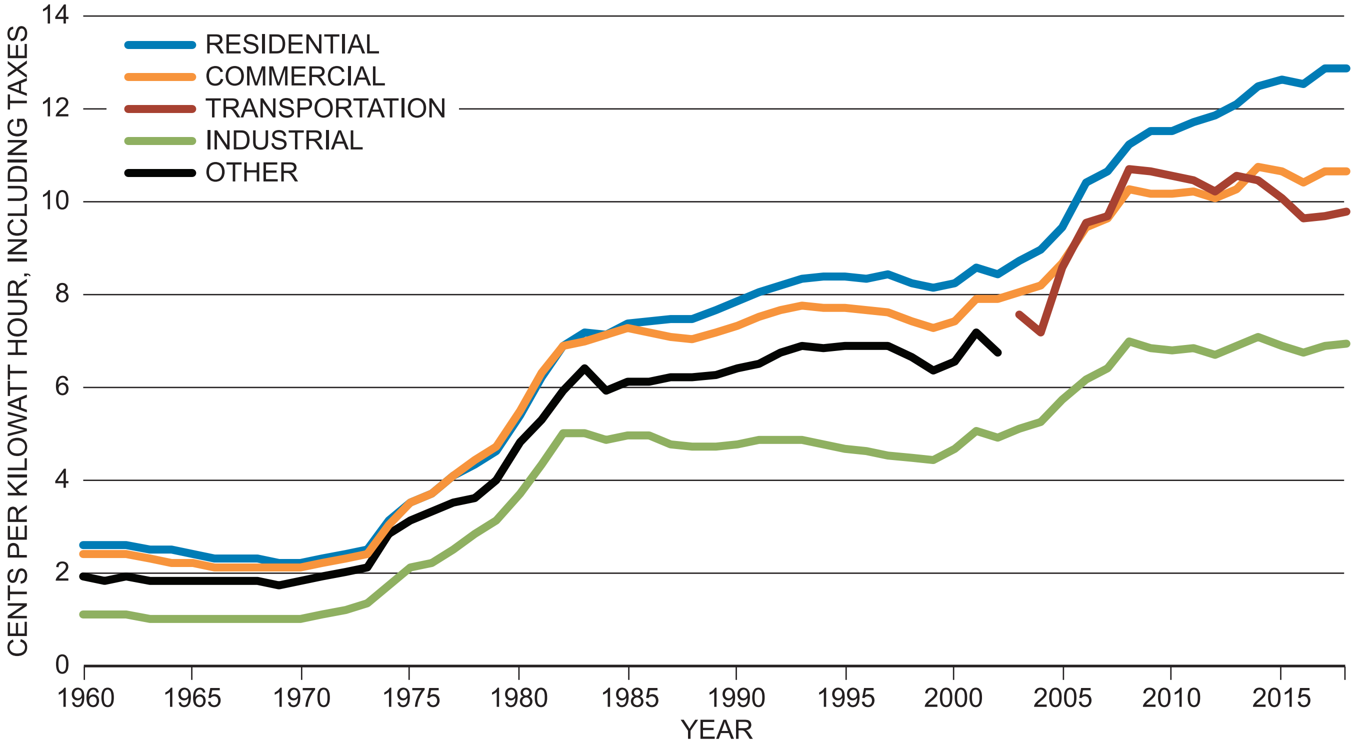
H. Regional and State Level Benefits

Recognizing the concerns of those who oppose the rapid growth in the industry due to environmental and quality of life issues, it is important to



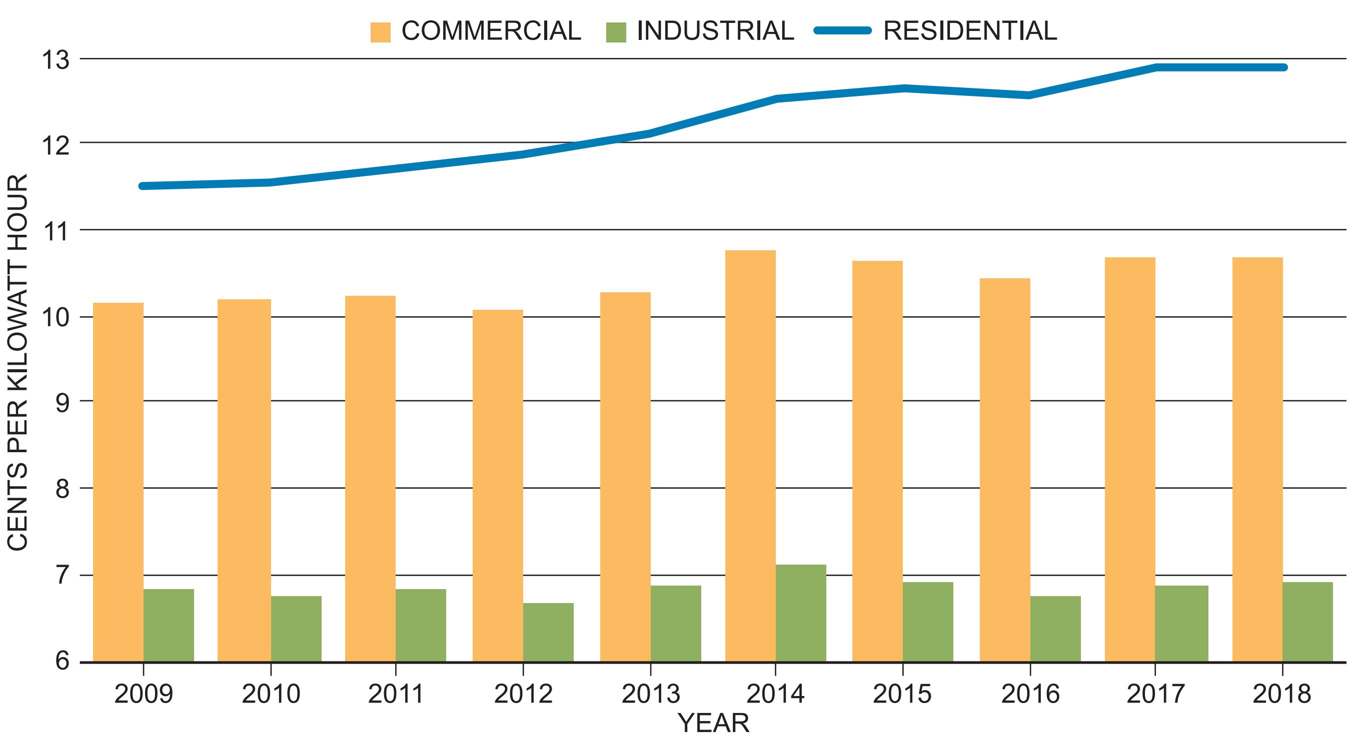
Source: EIA, Natural Gas, Prices, "Average price of natural gas delivered to residential consumers by state."

***Figure 2-95.** Price of Natural Gas Delivered to Residential Consumers, 2008 and 2017*



Source: EIA, *Monthly Energy Review*, Figure 9.2, September 2019.

Figure 2-96. *Average Retail Prices of Electricity by Sector*



Source: EIA, *Electric Power Monthly,* Average Price of Electricity to Ultimate Consumers.

Figure 2-97. *Average Price of Electricity to Customers*

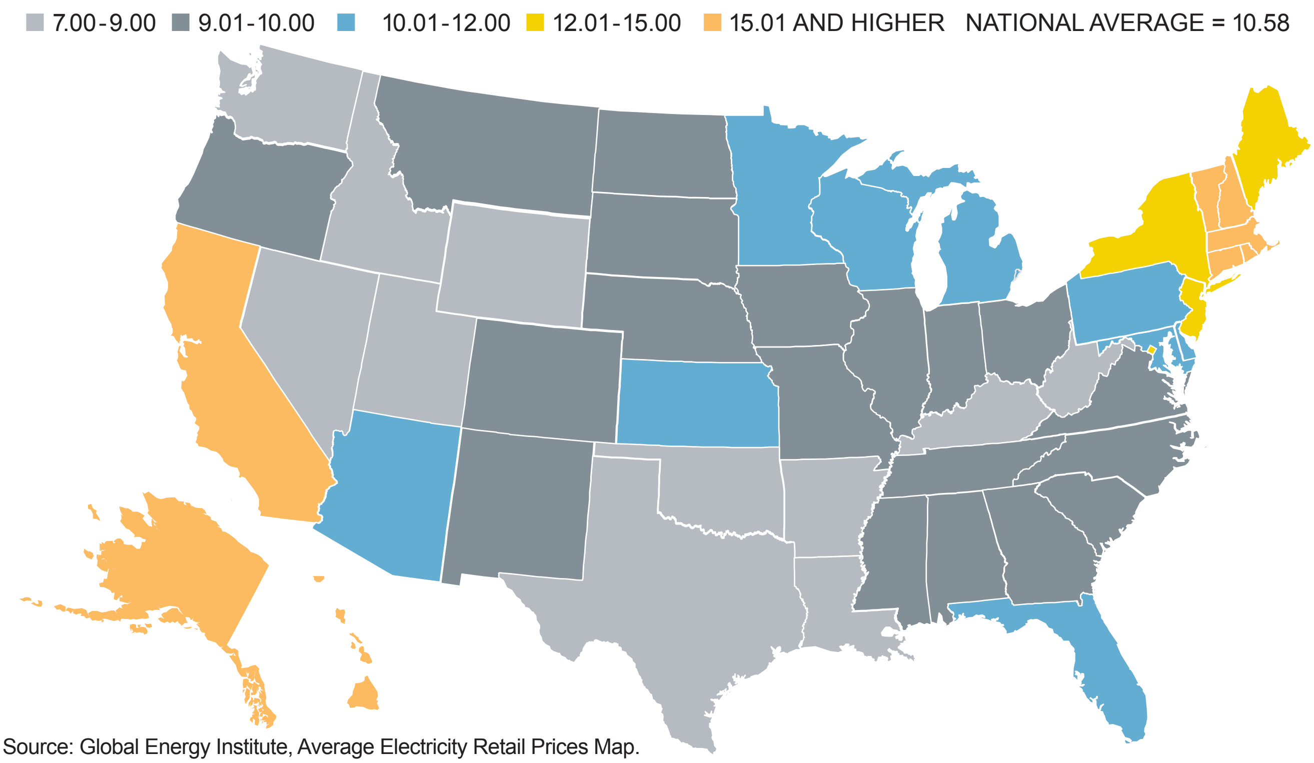


Figure 2-98. *2018 U.S. Average Electricity Retail Prices*

understand the positive outcomes realized by the states who have supported the growth of energy infrastructure and are benefiting from increase energy resources. Following are a few different approaches and examples.

1. Texas

As the largest producer and consumer of energy resources, between 2014 and 2024, the Texas pipeline industry is expected to contribute $374 billion in total economic output and it is estimated that between 2015 and 2035, almost 2 million infrastructure-related jobs will be created.[115]

2. Virginia

Increased use of natural gas has saved consumers in individual states millions of dollars. For example, natural gas use increased more than 50% between 2004 and 2014, with falling prices saving consumers more than $193 million compared to 5 years before. Industrial users saved $57.5 million. Schools and government also have benefited—Virginia Tech's ongoing switch to natural gas as the university's energy source will cut an estimated $1 million per year from its annual budget.[116]

3. Pennsylvania

Pennsylvania is the nation's second largest producer of natural gas. This abundance of natural gas has enabled the commonwealth to transition to greater natural gas use for electricity generation. The state has seen natural gas grow from representing less than 5% of electricity generation in 2005 to more than 36% of the state's electricity mix. The electric sector

115 Texas Tech University, *Current and Future Economic Impacts of the Texas Oil and Gas Pipeline Industry,* July 2014, https://texaspipelines.com/wp-content/uploads/2014/07/July-14-2014-Executive-Summary-The-Economic-Impact-of-Texas-Oil-and-Gas-Pipeline.pdf.

116 Green, M., "The Economic Case for Energy Infrastructure," API, https://www.api.org/news-policy-and-issues/blog/2017/05/03/the-economic-case-for-energy-infrastruct.

consumes roughly half of all natural gas used in the state.

Notably, from 2005 to 2015, Pennsylvania's overall carbon emissions decreased more than 17% and carbon emissions from electricity generation declined nearly 30%. The Pennsylvania Public Utility Commission estimates that the average Pennsylvania family is saving $1,200 annually on their home heating bills due to lower gas prices.

Pennsylvania and the Appalachian Basin should benefit greatly from dramatic growth anticipated in chemical processing and production, starting with Royal Dutch Shell's investment of more than $6 billion to construct an ethane cracker near Monaca, Beaver County. This facility is anticipated to spur the growth of a petrochemical manufacturing cluster to produce hundreds of consumer, medical, and commercial goods.[117]

117 Pennsylvania Independent Oil and Gas Association, "Benefits to Consumers in Pennsylvania: Residential, Commercial and Industrial," https://pioga.org/education/natural-gas-market-development/benefits-to-consumers-in-pa/.

4. Appalachia: The Connective Potential of Infrastructure: Appalachian Petrochemicals

Appalachia[118] has become the #1 natural gas-producing basin in the country. Natural gas produced in Appalachia is also rich in valuable NGLs (Figure 2-99). The combination of abundant, low-cost natural gas and NGLs provides a strong stimulant for economic growth in the region. Abundant, low-cost natural gas can serve as a petrochemical feedstock, and provide fuel for energy-intensive manufacturing. Further, natural gas-fired power generation provides low-cost electricity for all manner of industrial and commercial activity.

Appalachia has both ends of the petrochemical value chain: the local production of NGLs and downstream manufacturing that uses chemical intermediates (e.g., plastic resins) as feedstocks to make products that Americans use every day. What Appalachia lacks is the infrastructure to

118 The Appalachian region referred to here consists of Ohio, Pennsylvania, West Virginia, and Kentucky.

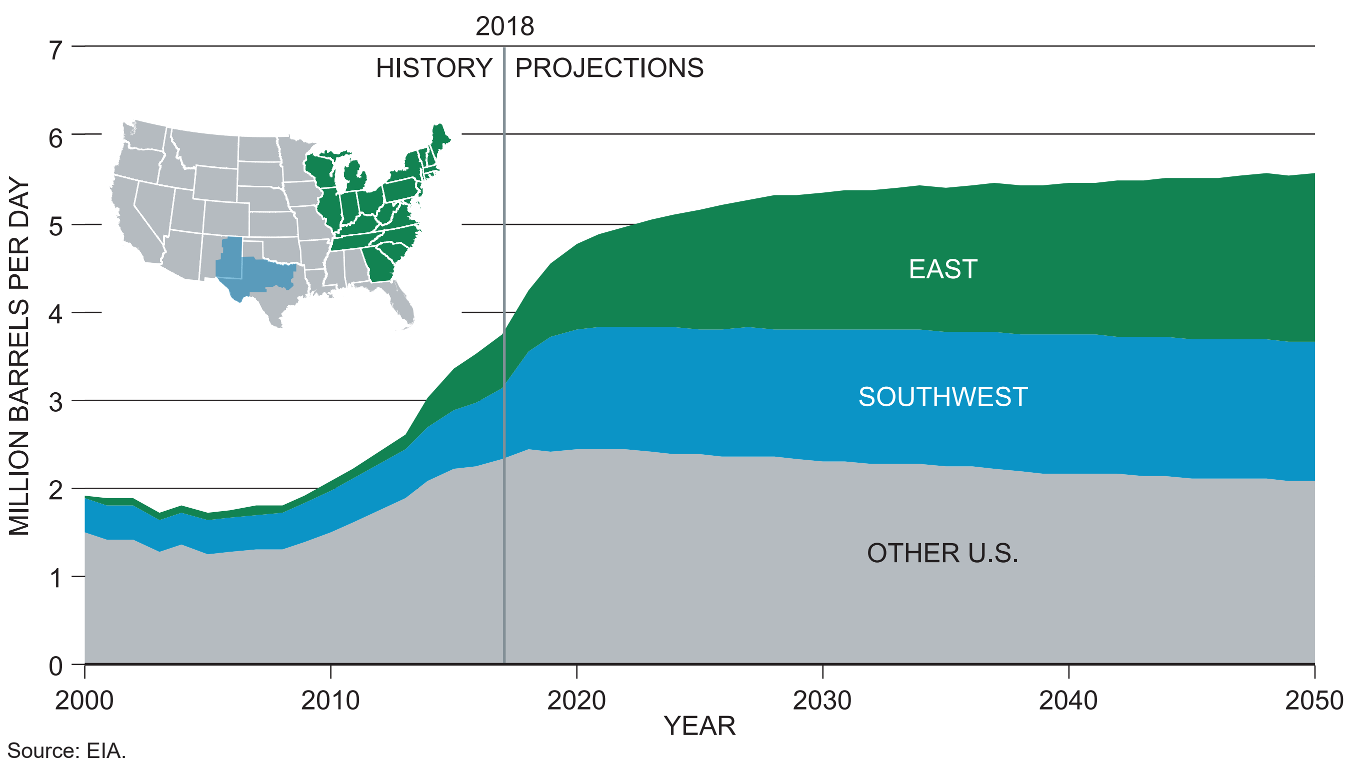


Figure 2-99. *U.S. NGL Production by Region*

process NGLs into the chemical intermediates required by downstream manufacturers. Currently, Appalachian NGLs are largely exported from the region and downstream manufacturers buy chemical intermediates from Gulf Coast petrochemical manufacturers. The development of a local petrochemical manufacturing infrastructure to connect these upstream and downstream markets would be advantageous due to the proximity to low-cost NGL feedstocks and proximity to downstream customers.

Natural gas from the Marcellus and Utica shale formations in the Appalachian Basin contains substantial volumes of NGLs such as ethane, propane, and butane. The EIA projects that NGL production will nearly double by 2050 in the eastern United States, dominated by Appalachian Basin production, contributing the largest share (30%) of U.S. NGL output.[119] Among the NGLs, ethane is considered one of the most important feedstocks for the petrochemical industry as it is used to create plastic resins, including polyethylene,[120] a $75 billion industry in the United States. It is projected that by 2025, ethane production in the Appalachian Basin will reach 640,000 barrels per day, 20 times greater than 2013, providing the necessary, low-cost feedstock for regional manufacturers to achieve a competitive advantage.[121]

Nearly one-third of U.S. manufacturing that involves petrochemicals occurs within 300 miles of the center of the Appalachian NGL producing area, generating over $300 billion of revenue, employing 900,000 workers, and supporting 7,500 businesses.[122] Appalachia is home to manufacturing operations of several large, downstream multinational plastics, chemical, and paint companies including PPG Industries, Dow Chemical, Sherwin-Williams, and more (Figure 2-100). Local plastics manufacturers and converters are major consumers of petrochemical products with approximately $93 billion in consumer revenue in the region annually.[123] Paint manufacturing is also a critically important local industry, providing 75% of total revenue and employment in the area.[124]

With limited NGL storage in the eastern region, building out the storage and conversion infrastructure (like crackers and petroleum dehydrogenation plants) in Appalachia would provide local manufacturers with the flexibility of procuring low-cost feedstocks and local storage, reducing transportation time and cost-per-mile, and eliminating the cost of infrastructure to transport NGLs to crackers outside of the region. In addition to accessing the domestic petrochemical market, Appalachia would also be able to continue to export NGLs and LNG through the East Coast of the United States. This access is critical as NGL exports are estimated to rise from 34% to 41% of production by 2020.[125] Markets outside the United States use a more expensive petrochemical feedstock called naphtha, so importing the lower-cost Appalachian NGLs is more cost effective than local production.

This growth in natural gas and NGL production in Appalachia, paired with the considerable market opportunity, has already attracted investments in petrochemical projects and has the potential to support additional infrastructure. While natural gas processing and regional fractionation capacity have been increasing to accommodate the increasing gas production, there is additional infrastructure required for local storage.[126] Storage is essential for NGLs because it helps ensure a steady source of feedstock. Increasingly companies are actively developing storage projects in the region to service their own storage needs or that of their customers. Two examples are recent projects by Sunoco and Energy Storage Ventures (both operate underground caverns).[127]

119 Office of Fossil Energy, U.S. Department of Energy, "Northeast Petrochemical Exhibition and Conference," June 20, 2019, https://www.energy.gov/fe/articles/northeast-petrochemical-exhibition-and-conference.

120 Polyethylene is the most commonly produced plastic globally. This polymer is used to make grocery bags, food packaging, plastic bottles, toys, housewares and more.

121 Office of Fossil Energy, U.S. Department of Energy, "Northeast Petrochemical Exhibition and Conference," June 20, 2019, https://www.energy.gov/fe/articles/northeast-petrochemical-exhibition-and-conference.

122 U.S. Department of Energy, *Ethane Storage and Distribution Hub in the United States*. Report to Congress, November 2018, 13, https://www.energy.gov/sites/prod/files/2018/12/f58/Nov%20 2018%20DOE%20Ethane%20Hub%20Report.pdf.

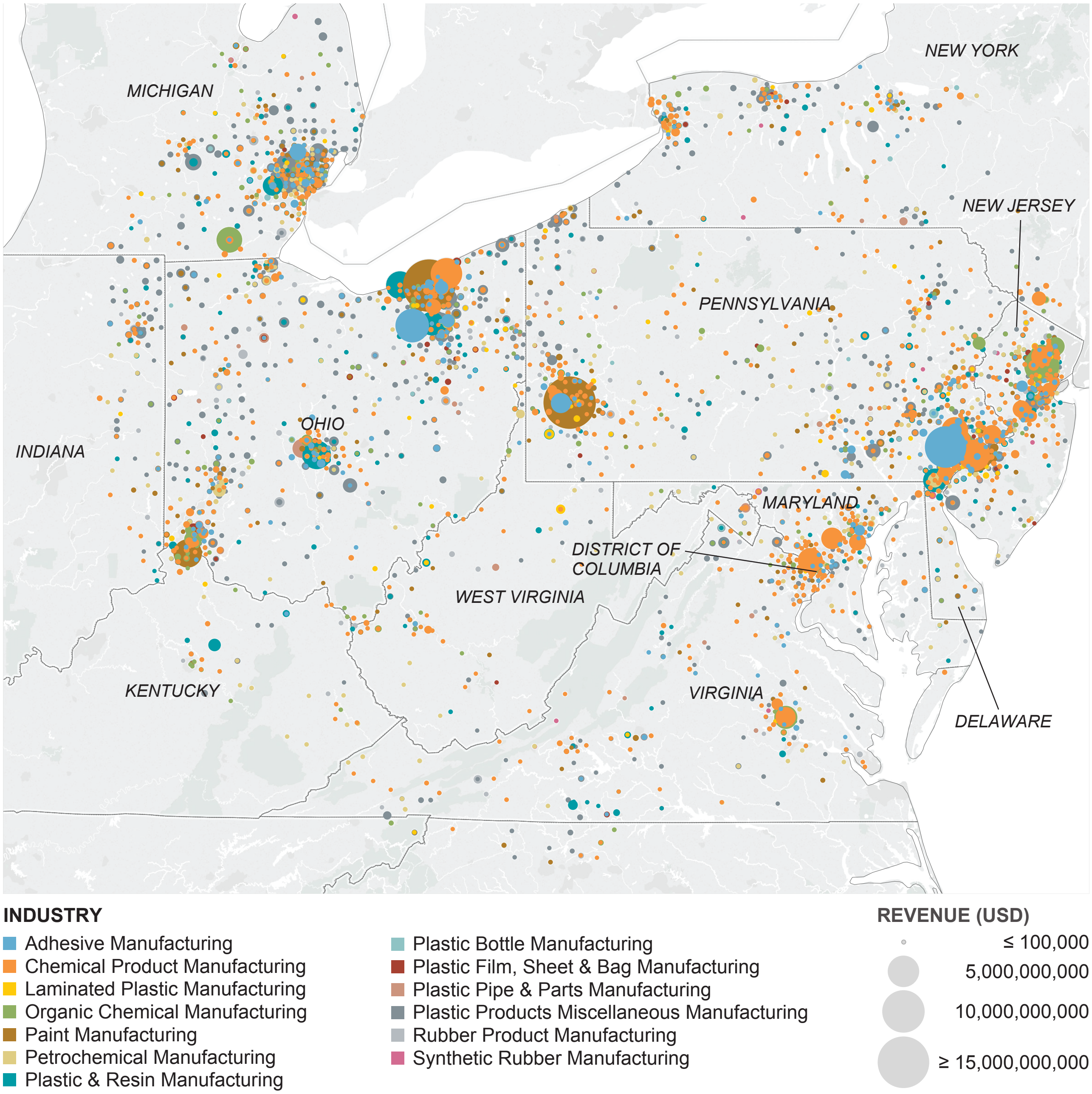
123 Ibid, 55.

124 Ibid, 56.

125 Ibid, 77.

126 Ibid, 28.

127 Ibid, 30.



Source: Department of Energy, Ethane Storage and Distribution Hub in the United States, Industry Revenue by North American Industry Classification System (NAICS) code within 300 miles of Pittsburgh, PA, with data from D&B Hoovers.

Figure 2-100. *Downstream Companies in the Petrochemical Value Chain within 300 miles of Pittsburgh*

Other essential infrastructure includes ethane crackers, which "crack" ethane molecules to create ethylene.[128] The only petrochemical cracker currently operating in Appalachia is the Westlake Chemicals plant in Kentucky, which has a capacity of 375,400 tonnes per year of ethylene.[129] Shell Chemicals is investing in an ethane cracker

128 Ethylene, derived from ethane, is a hydrocarbon used extensively in the chemical industry in the production of polyester resins, adhesives, paper, solvents, and more.

129 U.S. Department of Energy, *Ethane Storage and Distribution Hub in the United States.* Report to Congress, November 2018, 34, https://www.energy.gov/sites/prod/files/2018/12/f58/Nov%202018%20DOE%20Ethane%20Hub%20Report.pdf. and *Oil and Gas Journal,* "Westlake plans ethylene expansion at Kentucky plant," January 11, 2016, https://www.ogj.com/refining-processing/article/17249697/westlake-plans-ethylene-expansion-at-kentucky-plant.

and polyethylene plant in Pennsylvania, currently under construction, with a production potential of 1.6 million tonnes per year of ethylene.[130] In addition to these projects, IHS Markit estimates sufficient ethane in the region to provide feedstock for four additional world-scale ethane crackers, each with a capacity of more than 1 million tonnes per year of ethylene production annually.[131,132] In Ohio, PTT Global Chemicals and Daelim Industries are expected to make a final investment decision in the next year on a $10B+ new cracker complex on the Ohio River with a capacity of 1.5 million tonnes per year of ethylene production.[133] Investments such as Sunoco's $200 million expansion of the Marcus Hook NGL export facility near Philadelphia are allowing Appalachian-produced NGLs to reach other domestic and global markets.[134] Investments in pipelines, such as the Mariner West and the Appalachia-Texas-Express lines, have provided the ability to move NGLs to Canada, the Midwest, and Gulf Coast.[135] IHS Markit projects that another $7 to $10 billion will need to be invested in the next 6 years in NGL-related infrastructure like natural gas processing plants, pipelines, fractionators, and storage in the region.[136]

State and federal government support for the development of petrochemical and manufacturing infrastructure (including an ethane storage hub) in Appalachia is strong. As early as 2015, the Governors of the Tri-State region of Ohio, Pennsylvania, and West Virginia committed to the "Tri-State Shale Coalition Agreement."[137] The three states agreed to work together to promote the continued development of Appalachia's shale resource and attract oil and natural gas-related manufacturing to the region. The agreement, which has been extended through 2021, has been instrumental in facilitating research and innovation partnerships between universities and the private sector, organizing technical job trainings and other workforce development efforts, and promoting investments in transportation and infrastructure.[138] An example of such a partnership is Beaver County Community College's (CCBC) newly established process engineering technical degree to train students to work in the manufacturing sector. CCBC has raised almost $6 million to fund this program, including $1 million from Shell to build the on-campus Center for Process Technology Education.[139] In April 2019, President Trump issued the Executive Order on Promoting Energy Infrastructure and Economic Growth that called for a report to identify opportunities to promote the growth of petrochemicals and other industries, assess the potential for economic diversification, and support workforce development in the Appalachian region.[140]

Realizing the potential of abundant oil and natural gas resources through the redevelopment of the Appalachian petrochemical industry and the related impact on manufacturing and other industries, could economically benefit the Appalachian region through the revitalization of manufacturing activity, the creation of jobs, and tax revenue that can be reinvested in the local communities. According to the American Chemistry Council, investment in new petrochemical and

130 Project costs estimated at $6B+, and Shell is receiving a $1.65 billion subsidy from the state of Pennsylvania.

131 This would allow for a total of six world-class crackers in the region.

132 U.S. Department of Energy, *Ethane Storage and Distribution Hub in the United States*. Report to Congress, November 2018, 76, https://www.energy.gov/sites/prod/files/2018/12/f58/Nov%202018%20DOE%20Ethane%20Hub%20Report.pdf.

133 PTTGC America, "Project Facts," http://pttgcbelmontcountyoh.com/project-facts/.

134 Maykuth, A., "Sunoco's $200 million expansion at Marcus Hook terminus in Delaware County to create 1,200 construction jobs," *The Philadelphia Inquirer*, April 29, 2019, https://www.inquirer.com/business/energy/sunoco-plans-new-marcus-hook-construction-mariner-east-pipeline-20190429.html.

135 U.S. Department of Energy, *Ethane Storage and Distribution Hub in the United States*. Report to Congress, November 2018, 19, https://www.energy.gov/sites/prod/files/2018/12/f58/Nov%202018%20DOE%20Ethane%20Hub%20Report.pdf.

136 Ibid, 77.

137 Stewart, Jackie, "Governors of Ohio, Pennsylvania, and West Virginia renew pledge to support shale," Energy In Depth: Appalachian Basin, March 2018, https://www.energyindepth.org/governors-of-ohio-pennsylvania-and-west-virginia-renew-pledge-to-support-shale/.

138 Oil & Gas 360, "Marcellus, Utica Governors Re-Up Tri-State Shale Coalition," April 2018, https://www.oilandgas360.com/marcellus-utica-governors-re-up-tri-state-shale-coalition/.

139 Stonesifer, J., "Shell donates $1 million to CCBC's process technology program," *The Times*, February 2018, https://www.timesonline.com/news/20180220/shell-donates-1-million-to-ccbcs-process-technology-program.

140 "Executive Order on Promoting Energy Infrastructure and Economic Growth," The White House, April 2019, https://www.whitehouse.gov/presidential-actions/executive-order-promoting-energy-infrastructure-economic-growth/.

manufacturing infrastructure in Appalachia would generate $35.8 billion in capital investment; $28.4 billion in direct output; 100,118 (direct, indirect and payroll-induced) jobs; $6.2 billion in payroll; and $2.9 billion in federal, state, and local taxes by 2025.[141]

5. North Dakota: Value of Infrastructure in Connecting Resources to Markets

North Dakota has played a central role in enabling the United States to become a leading crude oil producer. With record production of 1.4 million barrels per day in December 2018, and again in June 2019,[142] from the Bakken formation, North Dakota is one of the nation's largest producers (second only to Texas) and accounts for an impressive 11.5% of U.S. total oil production.[143]

The Bakken formation is a layer of shale that lies beneath North Dakota, Montana, and parts of Canada and is one of the largest continuous crude oil accumulations in the United States, with some estimates of recoverable resource as high as 40 billion barrels of oil equivalent.[144,145] As of May 2019, there were 13,151 oil-producing wells in the Bakken,[146] a more than 2000% increase from the 582 producing wells in May 2008.[147] During the same period, Bakken natural gas production ballooned from 1.4 BCF in May 2008 to 85.7 BCF in May 2019.[148]

The benefits to North Dakota from Bakken production are undeniable. The oil and natural gas industry represented 4.4% ($2.25 billion) of North Dakota's GDP in 2017.[149] The industry also currently supports 72,000 jobs in the state.[150] As of July 2019, North Dakota had the second lowest unemployment rate in the United States, more than a full percentage point below the national average of 3.7%.[151] Nonetheless, the state recognizes the ongoing need for additional skilled labor to support the expansion of its oil and natural gas infrastructure and maximize public benefits for North Dakotans.

From 2008 to 2018, oil and natural gas taxes netted approximately $18 billion for the state, which accounted for more than 45% of total tax revenues.[152] Most of this tax revenue is used to fund specific state priorities including investments in communities, schools, local transportation, water projects, the North Dakota Legacy Fund, property tax relief, wildlife, and natural resources.[153] North Dakota embraces an "all-of-the-above" energy strategy[154] and pursues research through the University of North Dakota and collaborative partnerships on various topics including innovation in pipeline technology, optimization in resource recovery, and underground natural gas storage.[155]

141 American Chemistry Council, *The Potential Economic Benefits of an Appalachian Petrochemical Industry*, May 2017, https://www.americanchemistry.com/Appalachian-Petrochem-Study/.

142 Kringstad, J. J, "Monthly Update North Dakota Pipeline Authority," August 2019, https://ndpipelines.files.wordpress.com/2019/08/ndpa-august-15-2019-update.pdf.

143 U.S. Energy Information Administration, "U.S. Crude Oil Production Grew 17% in 2018, Surpassing the Previous Record in 1970," *Today in Energy*, April 9, 2019, https://www.eia.gov/todayinenergy/detail.php?id=38992.

144 Nicholson, Blake, "Officials Discuss Parameters of North Dakota Oil Study," AP News, April 2019, https://apnews.com/41fd238447e04713a8a5fadf5613dc08.

145 In December 2017, the U.S. Geological Survey committed to a new federal assessment of the Bakken and additional formations in the U.S. Williston Basin, as their prior assessment in 2013 may vastly underestimate the resource potential given the availability of new data and subsequent advances in technology. The effort is targeted for completion in late 2019. An accurate estimate of the oil and natural gas resource is important not only for producers, but also for planning and attracting investments in infrastructure, housing, roads and related industries.

146 Includes Bakken, Sanish, Three Forks, and Bakken/Three Forks Pools.

147 ND Monthly Bakken Oil Production Statistics, https://www.dmr.nd.gov/oilgas/stats/historicalbakkenoilstats.pdf.

148 North Dakota General Statistics, https://www.dmr.nd.gov/oilgas/stats/statisticsvw.asp.

149 Federal Reserve Bank of St. Louis, Economic Research, Archival Data, "Gross Domestic Product by Industry: Private Industries: Oil and Gas Extraction for North Dakota," https://alfred.stlouisfed.org/series?seid=NDOILGASNGSP (accessed November 7, 2019).

150 Energy of North Dakota, https://energyofnorthdakota.com/wewant/#prosperity.

151 U.S. Department of Labor, Bureau of Labor Statistics, "Local Area Unemployment Statistics," https://www.bls.gov/web/laus/laumstrk.htm.

152 Western Dakota Energy Association, "How the Oil Industry and Region Benefit and Support the State," https://taxstudy.ndenergy.org/TaxStudy.

153 Energy of North Dakota, Tax Revenues, https://energyofnorthdakota.com/home-menu/bakken-benefits/tax-revenues/.

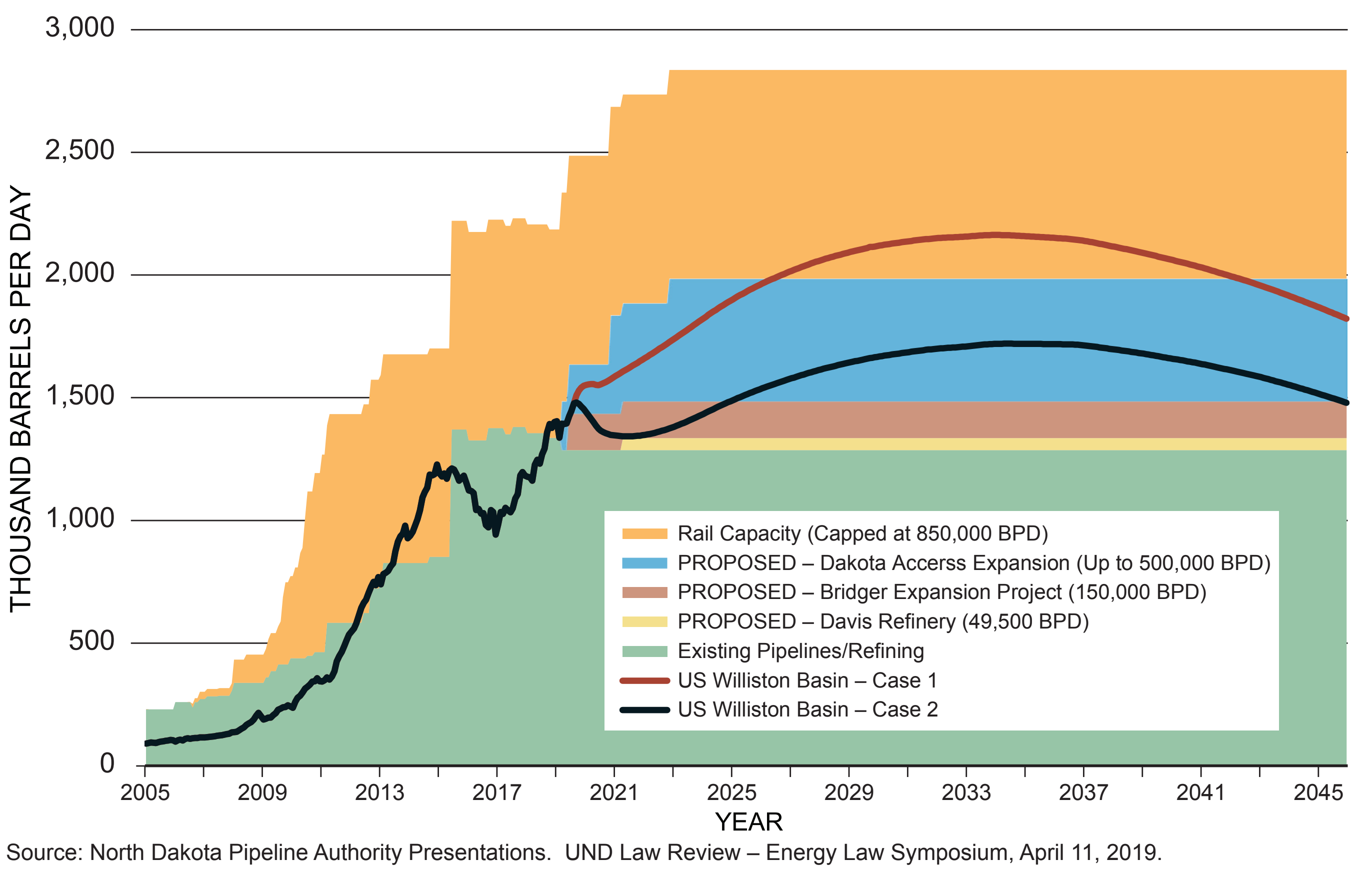
154 "All-of-the-above" energy strategy means that North Dakota utilizes all of its energy assets, e.g., wind, coal, oil, gas, biofuels, and solar.

155 University of North Dakota, Energy & Environmental Research Center, Oil and Gas Research, https://undeerc.org/research/oil-gas.html.

In March 2019, a compact between North Dakota and the Mandan, Hidatsa and Arikara (MHA) Nation changed how tax revenue from new oil and natural gas activity on tribal trust and fee lands are shared. On tribal trust lands, 80% will be allocated to the tribe and on fee lands (privately held lands that are leased), 20% of the revenue will be allocated to the tribe. Following two years of dialogue and collaboration, the historic agreement is expected to stimulate oil and natural gas investment and enable the MHA Nation to address community infrastructure needs and other priorities.[156]

156 Argus, "New ND tax-sharing law may spur Bakken oil production," April 2019, https://www.argusmedia.com/en/news/1878347-new-nd-taxsharing-law-may-spur-bakken-oil-production; North Dakota State Government, "Governor Signs Bill Ratifying Historic Oil Tax Revenue Sharing Compact with MHA Nation," March 2019, https://www.nd.gov/news/governor-signs-bill-ratifying-historic-oil-tax-revenue-sharing-compact-mha-nation; and Mark N. Fox, Chairman, MHA Nation, "MHA Nation and state successfully negotiate tax split," http://chairmanfox.com/2019/04/17/mha-nation-and-state-successfully-negotiate-tax-split/.

In 2007, North Dakota strengthened its approach to energy policy, creating the North Dakota Pipeline Authority (NDPA) and the EmPower Commission (Commission). The NDPA facilitates the development of pipeline facilities supporting the production, transport, and use of North Dakotan energy commodities to stimulate economic activity and increase employment. Figure 2-101 shows an example of NDPA's projections and analytics work, which is instrumental in supporting State infrastructure planning. It is a nonregulatory agency that specializes in providing data analytics and forecasting for transportation and processing in North Dakota. The 16-member Commission is made up of representatives from the state's diverse and growing energy industries and develops energy policy recommendations. The Commission's 2016 update made explicit that infrastructure is critical to the growth of communities and to enhance public safety. The Commission continues to make recommendations on infrastructure, research and development, and regulation such as expanding existing water systems



Source: North Dakota Pipeline Authority Presentations. UND Law Review – Energy Law Symposium, April 11, 2019.

Figure 2-101. *Williston Basin Oil Production and Export Capacity Projections* to match growing community needs and providing support to landowners on pipeline restoration and reclamation.[157] In addition to creating the Commission and NDPA, the state legislature invested $2.5 billion for critical infrastructure needs in 2013 (nearly double the amount appropriated in 2011) and the then governor of North Dakota committed $1.1 billion to road and infrastructure projects in 2015.[158]

Pipeline infrastructure is the primary means of transporting North Dakota's oil and natural gas to market, accounting for the majority of the natural gas and approximately 70% of oil movements out of state, with crude-by-rail transport supplementing pipeline capacity (averaging about 19% of the long-haul market) in 2018, and the remainder of the oil being either refined in state (6%), or sent by rail or truck to Canada (5%).[159]

In 2014, insufficient infrastructure to manage North Dakota's increasing natural gas production led to 36% of the state's natural gas being flared (Figure 2-102).[160] *Flaring* is the process of burning off natural gas produced as a byproduct of drilling for oil; though considered safer and more environmentally friendly than venting hydrocarbons into the air, flaring natural gas is wasted money—for both companies and communities. To limit natural gas flaring, North Dakota's Industrial Commission implemented a target of 88% natural gas captured (or 12% flared).[161] State data demonstrated

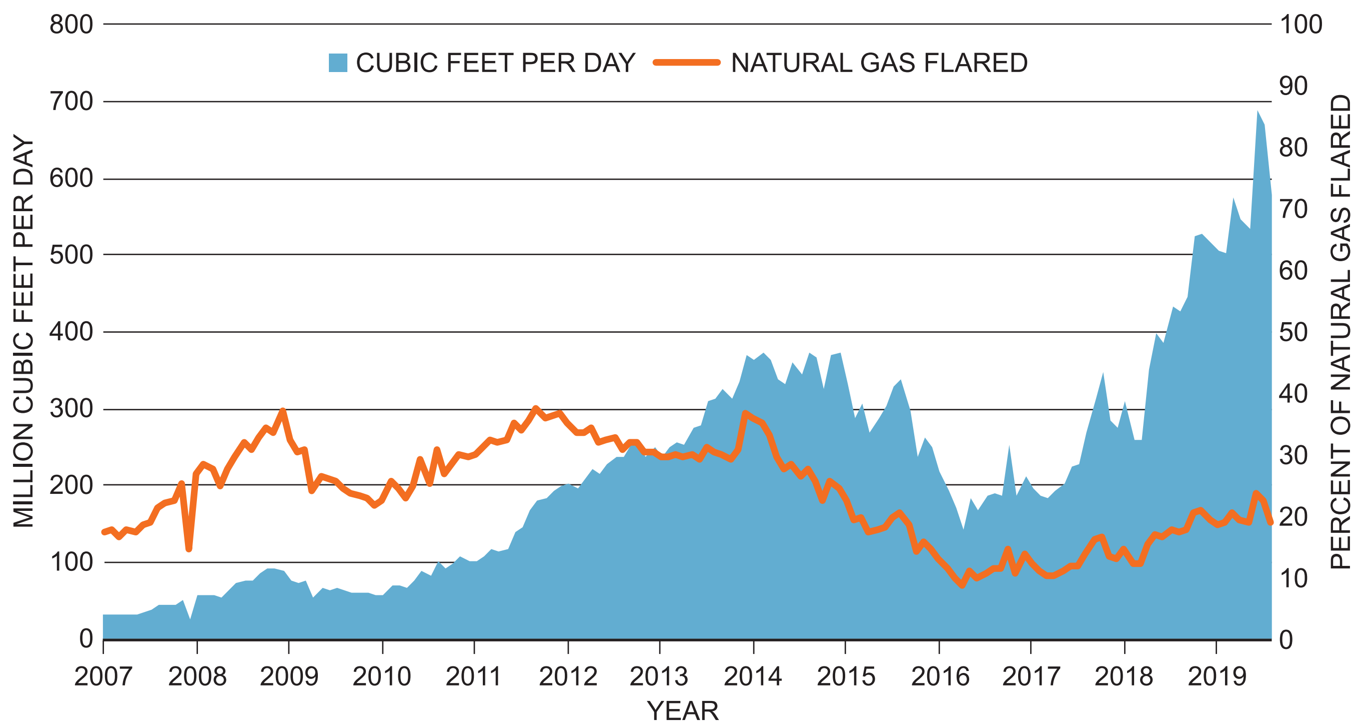
157 North Dakota State Government, *EmPower, North Dakota: Spotlight on Energy 2018*, https://www.business.nd.gov/energy/EmPowerNorthDakota/.

158 North Dakota Legendary, *Empower North Dakota: 2016 Policy Updates and Recommendations,* July 2016, https://www.business.nd.gov/uploads/14/nddoc2016empowerreportproductionv1.pdf.

159 Kringstad, J. J., "February 2019 Monthly Update," North Dakota Pipeline Authority, https://ndpipelines.files.wordpress.com/2019/02/ndpa-february-15-2019-update.pdf.

160 U.S. Energy Information Administration, "Natural gas flaring in North Dakota has declined sharply since 2014," *Today in Energy*, June 13, 2016, https://www.eia.gov/todayinenergy/detail.php?id=26632.

161 Macpherson, J., "North Dakota Oil Producers are Wasting Billions of Cubic Feet of Natural Gas," *Los Angeles Times*, May 27, 2019, https://www.latimes.com/business/la-fi-north-dakota-natural-gas-flaring-carbon-emissions-20190527-story.html.



Source: EIA, *Today in Energy*, November 28, 2017, based on well data from North Dakota Industrial Commission.

Figure 2-102. *EIA Historical Data on Flaring in North Dakota* a 40% decline in the volume of flared natural gas from about 0.35 BCF/D in 2014 to about 0.20 BCF/D in 2017.[162] Infrastructure shortfalls in 2018, however, increased the percentage of flared natural gas to 19% in late 2018 and early 2019.[163] Addressing natural gas flaring requires a toolbox of options suited to the circumstances, and more natural gas processing facilities are under construction or planned.

Due to limited in-state refining infrastructure, North Dakota ships approximately 10% of its oil by rail to refineries in Washington State. A new standard enacted by the state legislature of Washington in May 2019 prohibits oil from being unloaded at refineries within the state from rail cars that have a vapor pressure greater than 9 pounds per square inch (psi), which is well below accepted national standards.[164] This new standard would make it uneconomical to unload oil from the Bakken region in North Dakota and Montana at Washington state refineries. Washington's regulatory move sets the precedent that one state with access to particular transportation routes, namely rail-to-port, can restrict another state's ability to move its own natural resources across state borders.[165,166] In July 2019, the attorneys general of North Dakota and Montana filed a petition with the U.S. DOT that maintains that Washington's attempt to re-classify crude oil based on its vapor pressure is inconsistent with federal standards.

With the substantial increase in production, North Dakota has faced challenges with takeaway capacity and, consequently, price differentials. Producers in the Bakken sell at a discount, which affects the potential tax revenues that are reinvested into communities. As such, the Pipeline Authority has focused on completing new pipelines to connect North Dakota with Gulf Coast markets; this, in turn, has lowered transportation costs, making the price for Bakken crude oil more competitive. Even as major pipeline projects like Liberty and Red Oak have been announced, the NDPA has noted that more pipeline infrastructure is needed beyond 2020 to keep pace with expected production rates.[167]

6. Alaska Spotlight: Connecting Resources to Markets

The discovery of oil in Prudhoe Bay on the North Slope and Kuparuk in the late 1960s solidified Alaska's position as an oil and natural gas state.[168] Despite being home to several of the largest oilfields in North America, Alaska has fallen from second to sixth among U.S. oil-producing states.[169] The potential for technically recoverable oil in Alaska is astounding: the U.S. Geological Survey's (USGS) 2017 assessment of the National Petroleum Reserve–Alaska (NPRA) estimates 8.7 billion barrels of oil and 25 trillion cubic feet of natural gas in the Nanushuk and Torok Formations alone.[170] Additional resources (more than 31 billion barrels of conventional oil and more than 200 trillion cubic feet of conventional natural gas) exist in other North Slope areas, the Arctic National Wildlife Refuge, basins across the state,

162 U.S. Energy Information Administration, "Natural gas production in Bakken region increases at a faster rate than oil production," *Today in Energy*, November 28, 2017, https://www.eia.gov/todayinenergy/detail.php?id=33892.

163 Kringstad, J. J, "July 2019 Monthly Update," North Dakota Pipeline Authority, July 2019, https://ndpipelines.files.wordpress.com/2019/07/ndpa-july-16-2019-update-press-slides.pdf; and U.S. Energy Information Administration, "Natural gas flaring in North Dakota has declined sharply since 2014," *Today in Energy*, June 13, 2016, https://www.eia.gov/todayinenergy/detail.php?id=26632.

164 Dalrymple, Amy, "Washington Governor Sign Bill with New Bakken Crude Oil Requirements," *The Bismark Tribune*, May 9, 2019, https://bismarcktribune.com/news/state-and-regional/washington-governor-signs-bill-with-new-bakken-crude-oil-requirements/article_f7a392a0-47c7-5a1b-ba03-c25a8f3c7da9.html.

165 North Dakota State Government website, "North Dakota Files Petition Seeking to Overturn Washington State Law," July 2019, https://attorneygeneral.nd.gov/news/north-dakota-files-petition-seeking-overturn-washington-state-law.

166 Benzinga, FreightWaves, "North Dakota Files Petition to Block Washington State from Restricting Oil Train Shipments," July 2019, https://m.benzinga.com/article/14092703?utm_referrer=https%3A%2F%2Fwww.google.com%2F&utm_source=https%3A%2F%2Fwww.google.com%2F.

167 Nemec, R., "New Bakken Oil, Gas Takeaway Underway Unlikely to be Enough, Says North Dakota Regulator," *NGI Shale Daily*, December 7, 2018, https://www.naturalgasintel.com/articles/116716-new-bakken-oil-gas-takeaway-underway-unlikely-to-be-enough-says-north-dakota-regulator.

168 Alaska's Resource and Development Council, "Background," https://www.akrdc.org/oil-and-gas.

169 U.S. Energy Information Administration, "Rankings: Crude Oil Production," Alaska, July 2019, https://www.eia.gov/state/rankings/?sid=AK#series/46).

170 U.S. Geological Survey, "Alaska Petroleum Systems," https://www.usgs.gov/energy-and-minerals/energy-resources-program/science/alaska-petroleum-systems?qt-science_center_objects=0#qt-science_center_objects.

like the Susitna and Cook Inlet Basins in southern Alaska, and offshore in the Beaufort and Chukchi Seas,[171, 172] These estimates do not include the untapped unconventional resource potential of heavy oil, shale oil, and viscous oil (estimated at tens of billions of barrels), as well as shale gas, tight gas, and gas hydrates (estimated at hundreds of trillions of cubic feet).[173]

To connect the North Slope to refineries in Alaska, other states and foreign markets, the 800-mile long TAPS has been operating since 1977. Privately constructed, TAPS is an engineering marvel, with more than half the pipeline constructed above ground due to the permafrost across most of the state.[174] Today, TAPS is operating at just a quarter of its capacity.[175] While technology advances have allowed TAPS to safely operate at these lower flow rates, increasing oil production would ensure that TAPS remain continuously operable.[176]

The benefits of TAPS and the broader oil and gas industry are undeniable in Alaska. Alyeska, the transportation consortium run by the owners of TAPS, employs 800 employees and hundreds of contractors to maintain the TAPS infrastructure; 20% of their workforce is Alaska Native.[177] Beyond just TAPS, in FY2019, the oil and gas industry is expected to generate $2.64 billion in state revenue.[178] The industry accounts for one-third of Alaskan jobs (about 110,000 direct and indirect jobs) and half of the state-wide economy.[179] For every job in the oil and gas industry, there are an additional 20 jobs created throughout the economy.[180] No other private sector industry comes close to generating more economic impact in Alaska than oil and gas.[181]

The biggest economic impact for Alaskans comes from the Alaska Permanent Fund, created in 1976 to put aside oil revenues for future generations. To date, the fund has paid out $20 billion in annual dividends to Alaskans.[182] In 2018, each Alaskan received $1,600 for their dividend. In addition, the Alaska Native Claims Settlement Act (ANCSA) has created revenue sharing across the regional corporations for Alaska Natives. When mineral resources (oil and gas) are developed on Native Corporation land, all ANCSA shareholders benefit. Thus far, the regional corporations have received more than $1 billion that has been divided among shareholders.[183]

While existing infrastructure, such as TAPS, can be better utilized to move oil and some natural gas liquids to domestic and international markets, there is also opportunity for new natural gas infrastructure to be built. While the state ranks third in the nation in natural gas gross withdrawals, most of this natural gas is reinjected into oil fields to support oil production.[184] Alaska currently lacks a natural gas transmission pipeline to move its abundant natural gas resources. Investment in a "gasline" can reinvigorate the dormant Kenai LNG export facility, create additional economic opportunity across the state, provide affordable natural gas for power generation,

171 Stanley, A., Sieminski, A., and Ladislaw, S., "Trans-Alaska Pipeline System's 40th Anniversary," CSIS, June 2017, https://www.csis.org/analysis/energy-fact-opinion-trans-alaska-pipeline-systems-40th-anniversary.

172 Alaska Department of Natural Resources, Division of Oil & Gas, "Why Alaska?" http://dog.dnr.alaska.gov/Home/WhyAlaska.

173 Walsh, C., and Longan, S., "Alaska Department of Natural Resources: Oil & Gas Outlook and Permitting," Alaska Department of Natural Resources, January 2019, http://www.akleg.gov/basis/get_documents.asp?session=31&docid=8.

174 "Overview of TAPS," Alyeska Pipeline Service Company, January 2019, https://www.alyeska-pipe.com/TAPS.

175 National Petroleum Council, *Supplemental Assessment to the 2015 Report Arctic Potential*, 2019, https://www.npc.org/reports/2019-Arctic_SA-LoRes.pdf.

176 Ibid.

177 Alyeska Pipeline Service Company, "Overview of TAPS," January 2019, https://www.alyeska-pipe.com/TAPS.

178 Alaska Department of Revenue, "Spring 2019 Revenue Forecast," March 2019, http://www.tax.alaska.gov/programs/documentviewer/viewer.aspx?1531r.

179 Goldsmith, S., "Oil pumps Alaska economy to twice the size—but what's ahead?" Institute of Social and Economic Research, University of Alaska Anchorage, February 2011, https://pubs.iseralaska.org/media/b16ea75e-430e-4ff9-aa79-b295020f2334/oiltransformfinal.pdf.

180 McDowell Group, *The Role of the Oil and Gas Industry in Alaska's Economy*, Prepared for Alaska Oil and Gas Association, May 2017, https://www.aoga.org/sites/default/files/final_mcdowell_group_aoga_report_7.5.17.pdf.

181 Ibid.

182 Alaska's Resource and Development Council, "Alaska's Oil and Gas Industry: Background," https://www.akrdc.org/oil-and-gas.

183 Alaska's Resource and Development Council, "Alaska Native Corporations," https://www.akrdc.org/alaska-native-corporations.

184 U.S. Energy Information Administration, "Alaska: State Energy Profile Overview," https://www.eia.gov/state/?sid=AK.

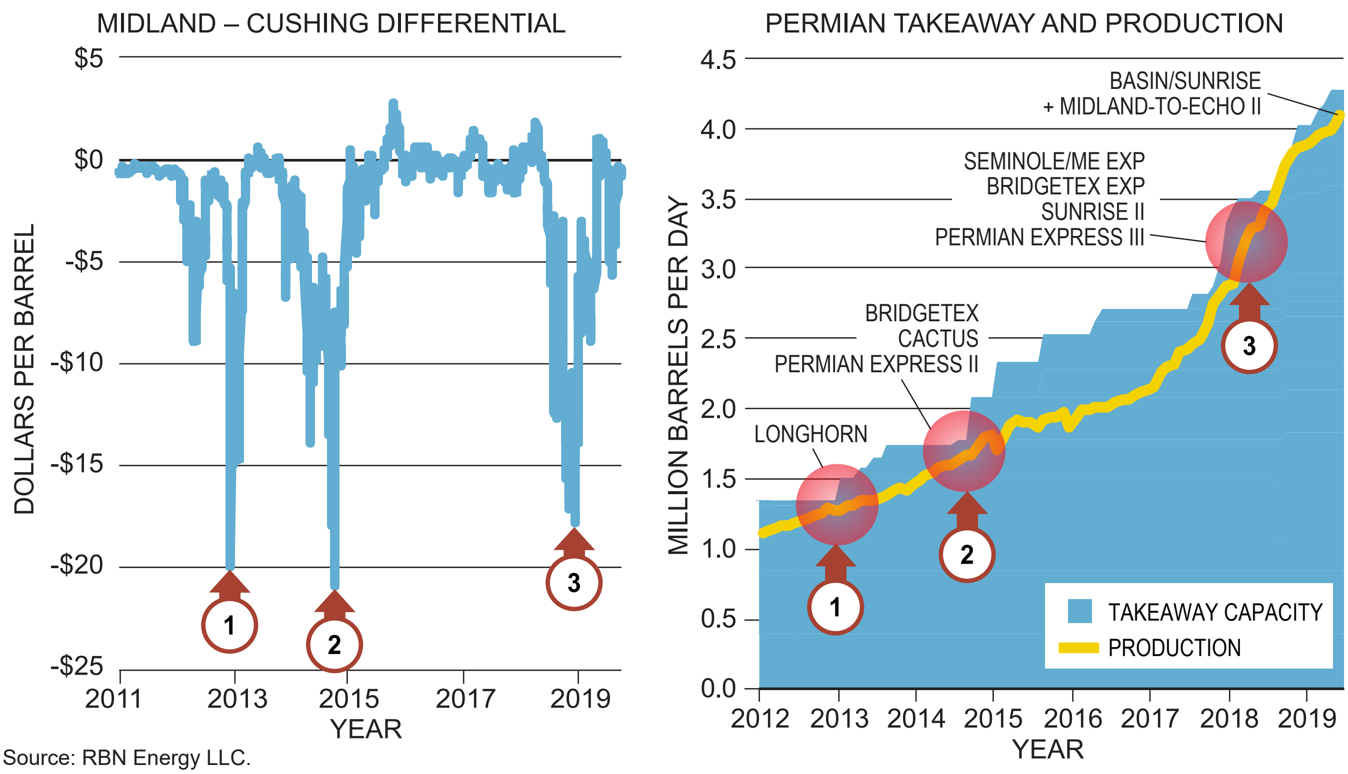


Figure 2-103. *Midland Cushing Differential & Permian Takeaway and Production*

and allow Alaskans to take advantage of the natural gas export market. The Alaska LNG project intends to construct a natural gas treatment plant in the North Slope, an 800-mile natural gas pipeline connecting the North Slope to Southcentral Alaska, and a liquefaction facility in Kenai.[185] In May 2019, BP and ExxonMobil each committed to investing $10 million to advance this $43 billion project. The pipeline is currently awaiting FERC approval in 2020.[186]

7. Permian Basin Infrastructure Constraints

The Permian Basin is example of how infrastructure constraints can temporarily lead to price discounts. These constraints develop due to lag time between growing production and the development of pipeline capacity.

185 Alaska LNG, "Project Overview," https://alaska-lng.com/.

186 The Associated Press, "Alaska oil producers to invest in natural gas project," *The Seattle Times*, May 30, 2019, https://www.seattletimes.com/seattle-news/northwest/alaska-oil-producers-to-invest-in-natural-gas-line-project/.

Figure 2-103 depicts the cycle of pricing behavior and infrastructure construction in the Permian Basin since 2011. At the #1 point in 2012, as production increased to equal takeaway capacity, the Permian Basin price (Midland) dropped to $20/barrel below the price at the Cushing, OK hub. The Longhorn Pipeline was then completed, relieving the constraint, and Midland prices recovered. At point #2, production again grew to equal capacity, and again the price differential widened. Three pipelines—Permian Express II, Cactus, and Bridgetex—were completed. The pattern was again repeated in 2018. Since then pipeline capacity has been able to stay just ahead of production, in part due to slowing production growth.

I. Findings and Recommendations

Findings:

- The increase in domestic natural gas supply has contributed to reduced carbon emissions in the U.S. power sector as gas-fired generation displaced coal-fired generation due to low gas prices. Fuel switching reduced emissions by nearly 300 million tonnes from 2000 to 2017.

- The rise of American shale gas has pushed down natural gas prices and underpinned large-scale switching from coal to gas both in the U.S. power sector and around the world. Since 2010, this switching has eliminated more than 500 million tonnes of CO_2 emissions worldwide.[187]

- The required infrastructure projects to support growth in exports of American oil, gas, refined fuels, and NGLs generate jobs and economic growth for specific states and regions, and the nation overall. A 2014 report developed by the Boston Consulting Group and the Harvard Business School estimated that unconventional energy development alone, contributed more than $430 billion to annual U.S. GDP and supported more than 2.7 million American jobs, ranging from those in exploration and production to supporting industries and local services. The projected growth in pipeline and gathering infrastructure spending alone between 2018 and 2035 in the United States could contribute more than $565 billion to U.S. GDP, $106 billion in federal taxes, and $91 billion in state and local taxes.[188]

- The abundance of U.S. energy supply has improved the competitiveness of energy-intensive sectors. Companies from around the world are investing in new projects to leverage this supply abundance, including new petrochemical operations in Pennsylvania and growth along the Gulf Coast. Since 2010, 334 projects cumulatively valued at $204 billion have been announced.[189]

- The benefits of this investment touch individual households in the form of reduced and more stable energy prices. Domestic natural gas prices have decreased due to increased natural gas supply, resulting in an increase in disposable income from $800 to $2,500 annually. Although electricity prices have increased over the last 10 years, the growth has been limited to 8%, well below growth trends of previous decades.

- The United States has moved among the top ranks of global crude oil and natural gas producers and decreased its own imports of crude oil, refined products, natural gas, and NGLs. This has improved the nation's trade deficit. IHS Markit estimates that the country's trade deficit in these products narrowed by nearly $250 billion while the total U.S. merchandise trade deficit remained little-changed (at $796 billion in 2017 versus $809 billion in 2007).

The NPC recommends that:

- Announced infrastructure projects, particularly pipelines and LNG export terminals, should be considered expediently by the relevant authorities and stakeholders so that they can be completed as planned and on time.

- The growth in American exports of oil, gas, refined fuels, and NGLs should be supported by policymakers and stakeholders.

187 International Energy Agency, *The Role of Gas in Today's Energy Transitions*, https://www.iea.org/publications/roleofgas/.

188 Interstate Natural Gas Association of America Foundation, Reports, June 18, 2018 release, North American Midstream Infrastructure through 2035.

189 American Chemistry Council, "U.S. Chemical Investment Linked to Shale Gas: $204 Billion and Counting," May 2019 Shale Gas Fact Sheet, https://www.americanchemistry.com/Policy/Energy/Shale-Gas/Fact-Sheet-US-Chemical-Investment-Linked-to-Shale-Gas.pdf.

VI. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Findings	Recommendations
II.A.4. Infrastructure Development Environment	
While market dynamics drive demand for diverse modes of transportation, the infrastructure system typically relies on pipelines as part of the long-term solution to efficiently and safely move supply to market centers.	
II.B. Crude Oil Infrastructure History and Current State	
Increases in crude oil supply can get to market quickly because of diverse transportation options. Increasing domestic supply has allowed the energy transportation system to become more resilient as additional infrastructure is built to meet geographic changes in supply location as well as supply growth. Crude oil storage is essential to the supply chain, providing flexibility to adapt to fluctuations in supply and demand. Storage near demand centers provides the additional national and economic security that refineries can continue to run for a period of time in the event of a supply disruption upstream. The growth in U.S. oil supplies has reduced the influence of overseas producing nations on the U.S. economy and has contributed to the diversity of global supply. All of this could not have come about without the significant buildout in infrastructure that has allowed the abundance of shale oil to reach markets domestically and internationally.	
II.C.6. Resiliency—Refined Fuels Transportation System	
U.S. refiners are pushing the limits of capacity utilization. With minimal slack in the system, loss of capacity can be significant and create cascading constraints on upstream production. Two mitigations to capacity risk are storage and exports.	

Findings	Recommendations
II.D.4. The Impact of Shale on Natural Gas — Change in Major Flow Patterns	
Infrastructure projects in the early phases of the shale development were generally accomplished using existing pipeline paths, and thus were able to be relatively economic and to avoid many of the environmental and land impacts of new pipeline construction. New supply sources of natural gas have fewer transportation options, and production levels may be impacted without significant natural gas pipeline investment. The current and next generations of major projects have generally moved beyond what can be done with existing infrastructure, and thus involve expensive and more impactful greenfield pipelines. This regional evolution heightens the importance of finding sufficient shipper commitments to support the economics of the new construction, and of overcoming approval and permitting obstacles, including stakeholder concerns. Pipelines and their shippers have to make a long-term commitment (20 to 30 years) based on the size and location of production areas and market areas at the time of investment, in an industry that is undergoing rapid dynamic changes in both. The history of the REX pipeline highlights one of the most significant challenges of infrastructure investment. The closest and previously highest-value consuming region, New England and New York, has been unable to get the natural gas pipeline capacity it needs due to a combination of opposition to pipeline projects and market structures that have hindered long-term shipper capacity commitments.	
II.D.6. Resiliency — Natural Gas Transportation System	
The interconnected nature of the natural gas pipeline network facilitates the competitive marketplace and ensures system and supply reliability. Natural gas underground storage is a primary tool in maintaining the resilience of the pipeline system.	
II.E.6. Resiliency — NGLs Transportation System	
Fractionation operations are particularly vulnerable to flooding from a storm on the Gulf Coast. Due to the significant capacity in the area, and interdependency between NGL, crude oil, and natural gas, disruptions can impact oil and natural gas production in other regions. Processing plant operations are vulnerable to winter storms. In the event of a disruption, oil and natural gas production can be impacted, and in areas like the Northeast where there is little spare processing capacity, impacts can be significant.	

Findings	Recommendations
II.F.1. Mobile Transport, Rail Transportation System	
The breadth of rail infrastructure, combined with rail's ability to add capacity in relatively small increments, provides shippers with the ability to quickly and efficiently access a broad network of potential origins and destinations. In rail corridors with constrained line and terminal capacity, timely permitting is critical to enabling rail to respond to shipper needs.	Maintain a rail regulatory infrastructure that facilitates continued private investment in a robust North American rail system. Continue to facilitate transition to DOT-117J/DOT-120J Next Generation tank cars for movement of flammable nonpressurized commodities. Provide a regulatory framework enabling timely permitting of rail-related projects on existing right-of-way, which is critical to enabling rail to respond to shipper needs.
II.F.4. Mobile Transport, Resiliency—Marine	
The Port of Houston is an essential energy port for the United States and presents a unique set of circumstances that must be considered in determining the proper approach to channel modifications. The inland waterway system requires proper investment in maintenance and capital improvements if it is to remain a reliable source of flexible energy transportation for the nation. As with other modes, the market will not create capacity simply for the sake of providing resiliency. However, capacity can be added when the market signals the need. Dredging ports used for energy transportation to their authorized depths and widths, and in some cases, increasing that authorized depth and width, will increase the efficiency of marine transportation. The government collects a harbor maintenance tax to maintain all deep-draft ports to their authorized depth and width.	The Houston Ship Channel study being undertaken by the U.S. Army Corps of Engineers should account for the unique nature of the Port of Houston and should recommend the widening of the channel to accommodate safe and efficient two-way traffic of all current and foreseen vessels calling in Houston. Congress should fully appropriate revenue coming into the Inland Waterways Trust Fund to fully maintain all U.S. port infrastructure at their authorized dimensions. Where warranted, Congress should authorize widening and/or deepening of channels to increase the capacity of ports to safely and efficiently transport energy cargoes. Congress should fully appropriate the revenue coming into the Harbor Maintenance Trust Fund to fully maintain all U.S. port infrastructure at their authorized dimensions.
II.F.6. Mobile Transport, Resiliency—Trucking	
Mobile assets such as railcars, trucks, and barges allow for commercial repurposing and provide greater flexibility than static infrastructure.	Create a regulatory environment that supports new infrastructure projects in areas where there are supply and demand imbalances. When possible, consider increasing the geographic diversity for all types of facilities, including new export facilities. Evaluate opportunities to decongest ship channels on the Gulf Coast to support the increased ship traffic. Adopt a review, revise, and refine approach to studying resiliency and infrastructure more consistently to address the constant changes to supply and demand.

Findings	Recommendations
III. Infrastructure Development and Regional Constraints	
Several critical infrastructure bottlenecks exist: natural gas pipeline access to New England/New York, Port of Houston capacity, and oil and natural gas export capability. Each of the United States' large production areas is unique, not only in its location and distance to primary markets, but in the mix of crude oil, natural gas, and NGLs produced there. To continue to support the development of supply, investment in new infrastructure is necessary.	
III.A.5. Flaring and Infrastructure Constraints	
In places like the Permian Basin and the Bakken, crude oil can only be produced if the natural gas that comes with it is produced. So, if producers lack sufficient gas pipeline infrastructure, all energy products are shut in. All of this comes with direct impact to the market, consumers, and royalty owners. Flaring is an important issue that energy producers take very seriously. The industry makes every effort to reduce flaring of natural gas, but sometimes must do so for safety reasons, regulatory requirements, or lack of sufficient infrastructure to move the natural gas to market.	Industry and federal and state agencies should continue to work together to ensure sufficient natural gas transportation infrastructure is in place on pace with development and production plans in growth basins to reduce flaring.
IV.E.1. Natural Gas Infrastructure and the Power Sector	
Renewables are expected to be a key component of national power demand. Natural gas is reliable and efficient for baseload electricity generation. Its flexibility also makes it well suited to meet peak demand and back up intermittent renewables.	

Findings	Recommendations
V. The Value of Infrastructure	
The increase in domestic natural gas supply has contributed to reduced carbon emissions in the U.S. power sector as gas-fired generation displaced coal-fired generation due to low gas prices. Fuel switching reduced emissions by nearly 300 million tonnes from 2000 to 2017. The rise of American shale gas has pushed down natural gas prices and underpinned large-scale switching from coal to gas both in the U.S. power sector and around the world. Since 2010, this switching has eliminated more than 500 million tonnes of CO_2 emissions worldwide. The required infrastructure projects to support growth in exports of American oil, gas, refined fuels, and NGLs generate jobs and economic growth for specific states and regions, and the nation overall. A 2014 report developed by the Boston Consulting Group and the Harvard Business School estimated that unconventional energy development alone, contributed more than $430 billion to annual U.S. GDP and supported more than 2.7 million American jobs, ranging from those in exploration and production to supporting industries and local services. The projected growth in pipeline and gathering infrastructure spending alone between 2018 and 2035 in the United States could contribute more than $565 billion to U.S. GDP, $106 billion in federal taxes, and $91 billion in state and local taxes. The abundance of U.S. energy supply has improved the competitiveness of energy-intensive sectors. Companies from around the world are investing in new projects to leverage this supply abundance, including new petrochemical operations in Pennsylvania and growth along the Gulf Coast. Since 2010, 334 projects cumulatively valued at $204 billion have been announced. The benefits of this investment touch individual households in the form of reduced and more stable energy prices. Domestic natural gas prices have decreased due to increased natural gas supply, resulting in an increase in disposable income from $800 to $2,500 annually. Although electricity prices have increased over the last 10 years, the growth has been limited to 8%, well below growth trends of previous decades. The United States has moved among the top ranks of global crude oil and natural gas producers and decreased its own imports of crude oil, refined products, natural gas, and NGLs. This has improved the nation's trade deficit. IHS Markit estimates that the country's trade deficit in these products narrowed by nearly $250 billion while the total U.S. merchandise trade deficit remained little-changed (at $796 billion in 2017 versus $809 billion in 2007).	Announced infrastructure projects, particularly pipelines and LNG export terminals, should be considered expediently by the relevant authorities and stakeholders so that they can be completed as planned and on time. The growth in American exports of oil, gas, refined fuels, and NGLs should be supported by policymakers and stakeholders.