North America Midstream Infrastructure through 2035

Significant Development Continues

The INGAA Foundation, Inc.

Prepared by

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About the INGAA Foundation: The Interstate Natural Gas Association of America (INGAA) is a trade organization that advocates regulatory and legislative positions of importance to the natural gas pipeline industry in North America. The INGAA Foundation was formed in 1990 by INGAA to advance the use of natural gas for the benefit of the environment and the consuming public. The Foundation, which is composed of over 200 members, works to facilitate the efficient construction and safe, reliable operation of the North American natural gas pipeline system and promotes natural gas infrastructure development worldwide.

About ICF: ICF (NASDAQ:ICFI) provides professional services and technology solutions that deliver beneficial impact in areas critical to the world's future. The firm combines a passion for its work with industry expertise and innovative analytics to produce compelling results throughout the entire program lifecycle, from research and analysis through implementation and improvement. Since 1969, ICF has been serving government at all levels, major corporations, and multilateral institutions. More than 5,000 employees serve these clients from more than 65 offices worldwide.

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Executive Summary

Midstream infrastructure development has occurred at a rapid pace over the past several years, causing many to question if the trend can continue. In response to those questions, the INGAA Foundation retained ICF to undertake a study to forecast the amount of midstream infrastructure development needed in the U.S. through 2035.

This study seeks to inform industry, policymakers and stakeholders of the dynamics of North America's energy markets based on a detailed supply/demand outlook for oil and gas development. The study assesses oil and gas infrastructure needed to support the delivery of crude oil and oil products, natural gas and natural gas liquids (NGLs).

This includes investments in new infrastructure within the following categories: a) surface and lease equipment; b) gathering and processing facilities; c) oil, gas, and NGL pipelines; d) oil and gas storage facilities; e) refineries and oil products pipelines; and f) export terminals. The study also projects the associated economic benefits of infrastructure development, most notably Gross Domestic Product (GDP) and employment.

Because the unit cost for pipeline construction has risen significantly in recent years, the study looks at two cost scenarios: Constant Unit Cost and Escalating Unit Cost. The Constant Unit Cost scenario assumes the unit costs for all assets remain constant in real terms throughout the projection. ICF derived these values for the year 2017, based on a time series regression of unit costs from 2001 through 2017. In the Escalating Unit Cost scenario, the unit costs rise in real terms in the projection. The escalation of the unit costs for pipeline and compressor station construction are determined based on regression of the historical unit costs with natural gas production growth then projected through the study period. Regressions were done by region because unit costs are very different across regions; for example, costs are higher in the Northeast, where projects have been in congested areas, but much lower in the South-Central region, which has lower construction costs due primarily to more rural infrastructure development.

In the body of this report, projected capital expenditures are presented as a range. For the purposes of the executive summary, capital expenditures are presented as a single number, which represents the average of the Constant Unit Cost Scenario and the Escalating Unit Cost Scenario. The economic impact figures (i.e., employment, Gross Domestic and State Products and tax revenues) are based on capital expenditure projections in the Escalating Unit Cost scenario. All other projections, including those for surface and lease equipment, as well as processing, gathering, pipeline export facilities, and storage capacity, are presented as a single number throughout the report.

Summary of key findings:

1) While midstream infrastructure investment is projected to peak in 2019, it nonetheless remains robust over the study horizon. The primary drivers for robust development are continued

unconventional resource development and strong market demand, largely in response to the relatively low commodity prices fostered by those new oil and gas supplies.

2) Capital expenditures (CAPEX) for new oil and gas infrastructure development total an average $791 billion from 2018 through 2035 (Exhibit ES-1). These levels of investment equate to an average annual CAPEX of $44 billion throughout the projection period (Exhibit ES-2).
3) Approximately 41,000 miles of pipeline and 7 million horsepower of compression and pumping are added to transport oil, gas, and NGLs from 2018 through 2035.
4) An additional 139,000 miles of gathering lines are added along with 10 million horsepower of compression and pumping to support gathering, processing, and storage of oil, gas, and NGLs during the study's forecast period.
5) Investment in infrastructure contributes $1.3 trillion to U.S. and Canadian Gross Domestic Products over the projection period, or approximately $70 billion annually.
6) Infrastructure development will result in employment of 725,000 U.S. workers annually. Significant employment opportunities are created not only within states where infrastructure development occurs but across *all* states because of indirect and induced labor impacts.
7) The infrastructure development in each of the scenarios is dependent on regulatory approvals of the projects.

Exhibit ES-1: Projected Capital Infrastructure Investment By type, 2018-2035 (Billion 2016$)

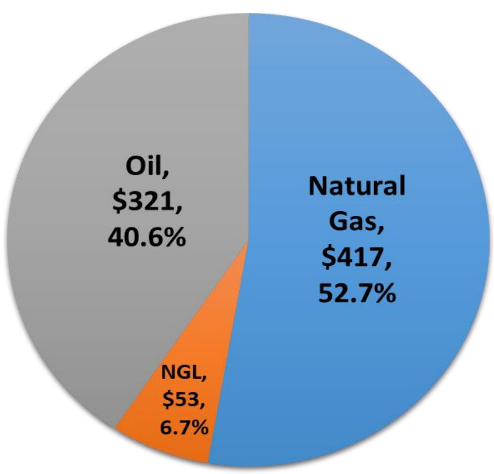
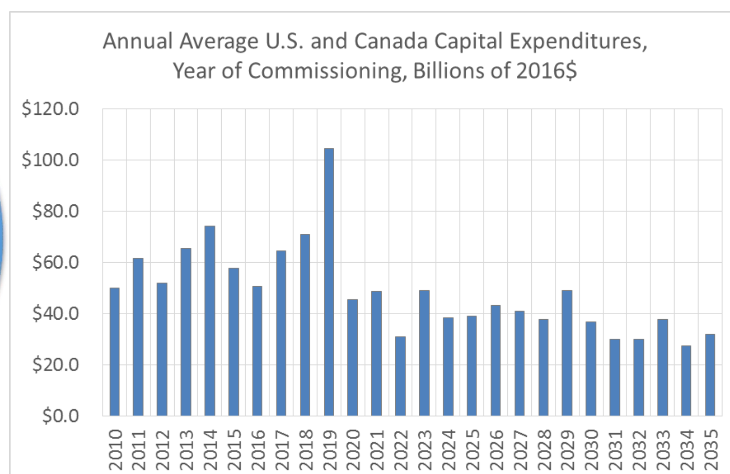


Exhibit ES-2: Oil and Gas Infrastructure (Billion 2016$)



Study Highlights

Several factors should increase supply and motivate infrastructure development. Notably, the North American unconventional resource base (shale and tight oil and gas) is enormous, with vast quantities of relatively low-cost oil and gas remaining to be developed. The application of technology is continuing to reduce well drilling and completion costs and enhance well productivity. Thus, the unit cost of oil and gas production continues to decline.

In addition to the productivity gains and cost reductions, markets appear poised for growth. Indeed, refinery input and output has increased during the past few years as North American oil production creates renewed interest in refinery investments to increase product output. Petrochemical facilities have undergone a resurgence and will continue to do so, as supply development continues to put downward pressure on natural gas and NGL prices.

Natural gas exports are on the cusp of growing significantly, both to Mexico and as LNG to markets around the globe. Further, low gas prices have fostered growth in the power generation market as coal and nuclear plants continue to be retired across the U.S. This trend seems irreversible considering regulations that encourage clean power and the way in which gas complements renewables. Regardless of policies, the relatively low gas price environment generally discourages additional investment to upgrade or further limit emissions from coal plants, especially considering the threat of federal carbon control that still looms on the horizon.

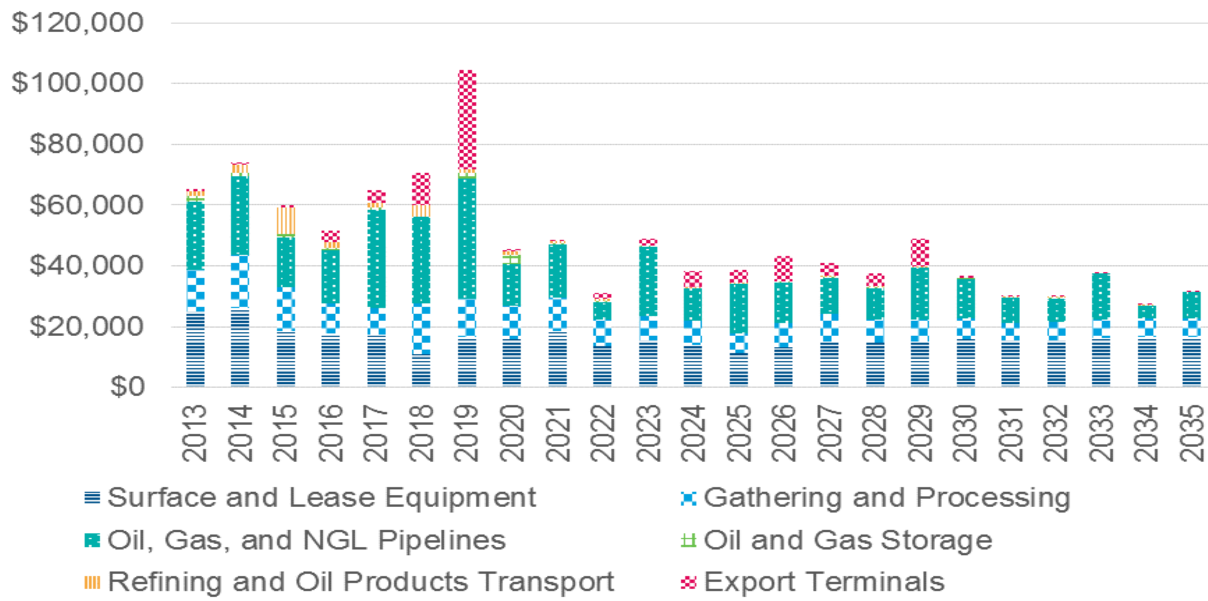
The scenarios in this study project significant growth in oil and gas production and markets that stimulate such growth. U.S. and Canadian oil production increases to over 19 million barrels per day by 2035. Natural gas production growth is even more pronounced, increasing from roughly 91 billion cubic feet per day in 2017 to 130 billion cubic feet per day by 2035. NGL production will track gas production over time.

Robust development of unconventional oil and gas resources and the supporting market activity promote the need for new transport capability for oil and gas. As a result, transport capability for oil, gas and NGLs increases by 3.6 million barrels per day, 56.7 billion cubic feet per day and 7.7 million barrels per day, respectively. Increased production also supports a significant amount of new gathering and processing infrastructure.

Thus, investment in new oil and gas infrastructure will total $791 billion from 2018 through 2035, averaging $44 billion per year. Roughly 34 percent of the investment, or $15 billion annually, will be for surface and lease equipment (Exhibit ES-3), which is split between investment in equipment that supports production from onshore wells and development of offshore platforms located in the Gulf of Mexico.

Oil, gas, and NGL pipeline development will see annual average CAPEX of $14.7 billion from 2018 through 2035, also equating to approximately one-third of total infrastructure investment. Across the U.S. and Canada, the report estimates construction of over 41,000 miles of oil and natural gas transmission pipelines with over 7 million horsepower of compression and pumping added throughout the projection period. Gathering and processing investment ranks third among the investment categories, with an average annual CAPEX of $8.4 billion, accounting for roughly 19 percent of the total infrastructure investment. The report estimates the need for about 139,000 miles of gathering pipeline, with about 64 percent of that focused on gas gathering. This investment is aimed at gathering and processing oil, gas and NGLs from 28,500 new well completions per year. The remainder of the investment, or $5.8 billion per year, is required to support refining, storage and export activities.

Exhibit ES-3: Average Annual Oil and Gas Infrastructure CAPEX by Category (Million 2016$)



Natural Gas

The study projects significant growth in natural gas production and consumption. Improved recovery factors and accelerated technological advancement yields lower gas prices, and thus, greater market growth.

U.S. natural gas production is concentrated in shale and tight formations. Because production costs are relatively low in the Marcellus and Utica compared with production costs elsewhere, the study anticipates both production and infrastructure needs related to natural gas will be focused in the U.S. Northeast.

The market for U.S. and Canadian natural gas consumed here and exported abroad will increase to 130 billion cubic feet per day from current levels of around 91 billion cubic feet per day. Gas markets grow dramatically, with significant growth of:

1. Liquefied natural gas (LNG) exports,
2. North American gas-fired power generation,
3. Pipeline exports to Mexico, and
4. Increases in U.S. petrochemical activity

LNG exports, which increase to over 12 billion cubic feet per day in the study, represent one of the largest growth markets. LNG exports are supported by 15 to 30 trains of liquefaction capacity, almost entirely located along the U.S. Gulf Coast. A significant amount of liquefaction capacity is already under construction and scheduled to come online over the next few years.

The second-most noticeable area of growth for gas use comes from the power sector, where gas use in the U.S. and Canada increases 17 billion cubic feet per day. This is driven by retirement of coal-fired power plants, which will be replaced by low-cost natural gas and renewable generation, as well as higher electric load and nuclear plant retirements. Natural gas will also serve as a backstop to help firm up variable renewables, like wind and solar, which are expected to grow during the projection period. This study assumes electric load growth consistent with ISO projections. It also assumes that many nuclear plants retire after they reach the age of 60 years.

The final two growth components for natural gas consumption are exports to Mexico and petrochemical gas use. Exports to Mexico rise by roughly 3 billion cubic feet per day, driven by replacement of Mexico's oil-fired generating facilities with gas-fired generating facilities. Petrochemical gas use in the U.S. grows by between 1 billion and 2 billion cubic feet per day. Most of the increase occurs at refineries, ammonia (fertilizer) plants and for methanol production.

CAPEX for natural gas infrastructure totals $417 billion, equating to 52.7 percent of the total investment in new infrastructure throughout the projection. Much of the investment in gas infrastructure, or $279 billion, is in gas gathering and transmission systems. The most intensive capital expenditures for natural gas infrastructure occur to gather and transport Marcellus and Utica as well as Permian Basin supplies to markets.

The study projects the need for 57 billion cubic feet per day of new pipeline capacity over the study period to support the levels of production and market growth that are projected through 2035. That means an average of 3.1 billion cubic feet per day of incremental transport is added annually to an already extensive gas transportation network. The size of the U.S. gas transportation network will increase at a rate of roughly 2.5 percent per year in the future. The study estimates about 25 billion cubic feet per day of new capacity to move Marcellus and Utica supplies to consumers and export facilities through 2035.

The study also forecasts construction of roughly 1,400 miles of natural gas pipeline each year, with a total of 26,000 miles put in place throughout the projection. There is both significant upside potential and significant risk for natural gas pipeline development, depending on market evolution and project approvals. The study estimates 391,000 horsepower of compression added each year, or a total of 7 million horsepower of compression over the course of the projection.

Oil

The study shows growth in total crude oil production for the U.S. and Canada over the course of the projection period. Increases in the Permian, Niobrara and Bakken oil production more than offset declines in conventional production. As a result, total U.S. production increases from its current level of roughly 14 million barrels per day to nearly 20 million barrels per day by 2035. This growing supply results in the need for new pipeline transport and oil handling capability.

The study sees U.S. and Canadian refinery output increasing as production from tight oil supplies and imports of heavy crude from Western Canada grow. Refinery crude oil input increases from its current level of 18.8 million barrels per day to 20.5 million barrels per day because of refinery upgrades and refurbishments.

Not only do the increased supplies of Canadian oil and the lighter sweeter crudes increase refinery input over time, but they also displace crude oil imports from other countries. The increase of domestic crude oil production along with the incremental imports of heavy crude oil from Western Canada potentially cut crude oil imports from other countries in half over time. Increasing refinery input would increase oil product output and potentially boost U.S. exports of refined products.

CAPEX for oil infrastructure totals $321 billion, equating to 40.6 percent of the total investment on new infrastructure throughout the projection. Investment in oil infrastructure is widely spread across many types of infrastructure, including pipelines, gathering systems, storage terminals, offshore platforms, and refinery capacity. Investment in oil pipelines accounts for $53 billion of the total investment in this category. Much of the capital expenditure for oil infrastructure is focused on the Permian and Delaware Basins of West Texas and Eastern New Mexico, where large, relatively low-cost oil resources remain to be developed.

The study estimates the addition of 7.7 million barrels per day of new oil pipeline capacity. A significant part of the new transport capability (0.9 million barrels per day) is already under construction and scheduled to be completed within the next 12 months (year 2018-2019).

Geographically, the capacity is concentrated in the Central, Midwest and Southwest regions. Incremental transport in the Central and Midwest is already being added to support imports of heavy crude oil from Alberta's oil sands. These are legacy projects that were already underway before the collapse in oil prices and near-term slowdown in oil sands development. Another portion of the capacity is aimed at transporting incremental supplies from the Bakken toward the East Coast and Gulf Coast. Yet another portion of the capacity transports growing supplies of West Texas crude oil to refineries concentrated mostly along the Texas Gulf Coast.

Most new U.S. oil pipeline transport projects are forecast for completion in the next five to 10 years (2023 to 2028). As oil production growth slows over the projection period, the need for incremental capacity also slows as already-built capacity is relied on to transport incremental supplies.

NGLs

NGL production grows by roughly 3.5 million barrels per day through 2035. NGLs track natural gas production over time because NGLs are a by-product of the gas production stream. NGL production growth is concentrated in unconventional resources.

The U.S. NGL market grows by 3.2 million barrels per day. The biggest growth components for NGLs are exports, which increase by 1.5 million barrels per day. Propane, most of which is exported to Asia to support polypropylene production, represents the single largest export component. Ethane, which is used in ethane crackers domestically to produce ethylene, sees the second largest growth. More modest growth occurs for butane and pentanes+, which are used mostly in refineries.

CAPEX for NGL infrastructure totals $53 billion, equating to 6.7 percent of the total investment in new infrastructure throughout the projection. Investment in NGL infrastructure is spread across fractionation facilities and pipelines.

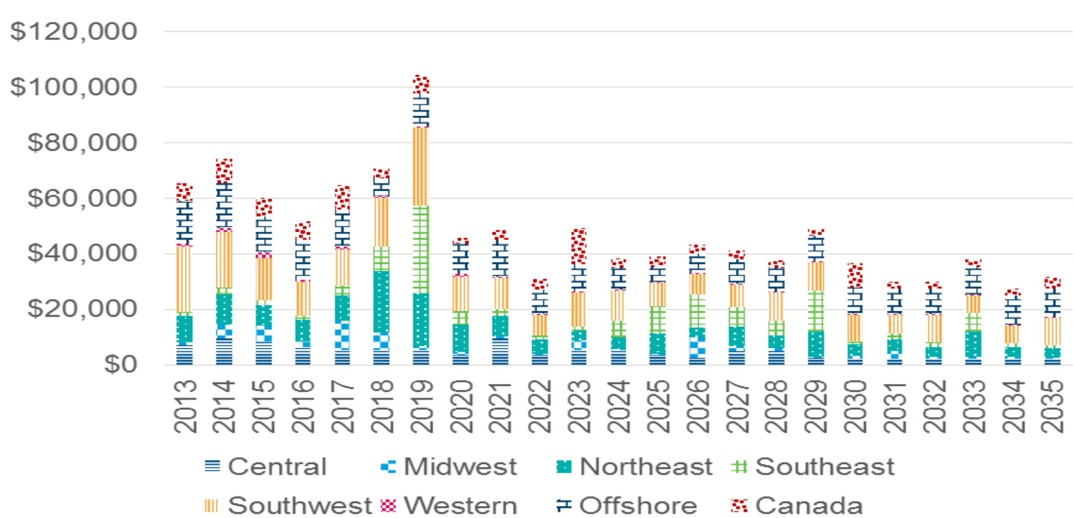
The study projects the development of 3.6 million barrels per day of new NGL pipeline capacity to support the production and market growth projected through 2035. Almost all this new capacity will be placed in service over the next decade.

The areas for development of new capacity include the: 1) Northeast – home to the Marcellus and Utica, where gas production is likely to continue to grow very rapidly; 2) the Midwest, where the Aux Sable liquids extraction facility resides; and 3) the Southwest, where there are potentially many "wet" gas plays that contain significant amounts of liquids resource. The last of these areas, the Southwest, is also home to Mont Belvieu, Texas, a widely recognized location for NGL transactions, that is near several sites where additional petrochemical facilities (i.e., ethane crackers and polypropylene plants) and NGL export terminals could be built or expanded.

Geographic Trends

Geographically, the Southwest, which includes Texas, will see the greatest oil and gas infrastructure investment with a total CAPEX of $193 billion, accounting for 24 percent of the total infrastructure investment across the U.S. and Canada (Exhibit ES-4). It should come as little surprise that this area leads the way on infrastructure development because it is accustomed to oil and gas development and is home to many production, refinery, petrochemical and export facilities and pipelines. However, the combined Northeast and Midwest region also will see a significant investment in oil and gas infrastructure, with the total investment of $163 billion for those regions combined, accounting for 21 percent of the total oil and gas infrastructure investment across the U.S. and Canada. Developing and transporting the vast amount of natural gas resources contained in the Marcellus/Utica producing basin is the focus of this investment. Infrastructure development for this area will depend on regulatory approvals of pipeline projects and market evolution. Offshore Gulf of Mexico infrastructure development is also significant at $167 billion, accounting for 21 percent of the total investment that occurs across each of the scenarios. Collectively, other geographic areas account for the remaining $268 billion, or 34 percent of the total U.S. and Canadian investment across the projections.

Exhibit ES-4: Regional CAPEX for Oil and Gas Infrastructure from 2018-2035 (Million 2016$)



Economic Impacts

Infrastructure development will continue to have significant and widespread impacts on the U.S. and Canadian economies. It will support an average of 725,000 jobs each year from 2018 through 2035. It will also add a combined total of $1.3 trillion or an annual average of $70 billion to U.S. and Canada Gross Domestic Product. Federal taxes related to oil and gas infrastructure development will total $238 billion, while state, provincial and local taxes will total $204 billion throughout the projection period. All states benefit from infrastructure development because there are indirect and induced employment benefits spread to states even where there is no infrastructure development.

Conclusion

The favorable economic environment for oil and gas infrastructure development has not yet run its course and is likely to continue for many years, with total investment in oil and gas infrastructure expected to be $791 billion from 2018 through 2035. This investment will have positive impacts on the U.S. and Canadian economies, employing many individuals and contributing significantly to Gross Domestic Product. Energy infrastructure development will also foster the delivery of lower cost energy to households and businesses, help the upstream and downstream portions of the oil and gas business develop more fully over time and support the penetration of renewable energy in the U.S. electric-generation market.

Exhibit ES-5: New Pipelines and Compression from 2018-2035 (Million 2016$)

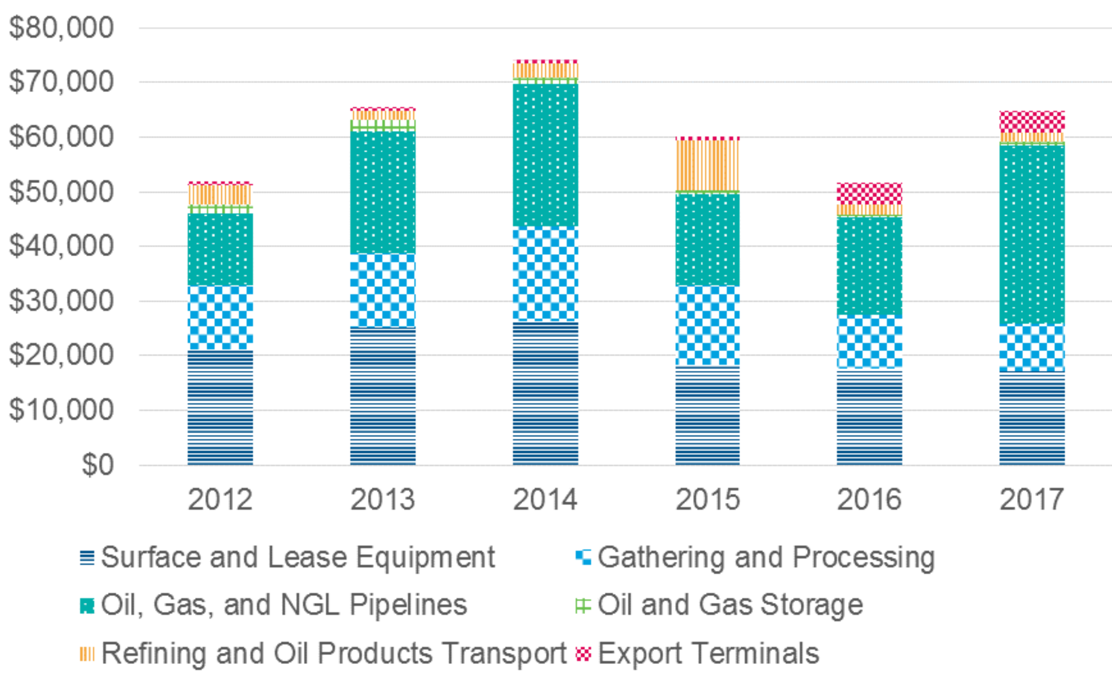
	Total 2013-2017	Total 2018-2035	Average 2013-2017	Average 2018-2035
Oil, Gas, and NGL Transmission Pipelines				
Oil Line Miles	15,617	8,184	3,123	455
Oil Line Diameter (Inch)	22.0	28.9	22.0	28.9
Pump for Oil Lines (1000 HP)	2,964	1,016	593	56
NGL Line Miles	10,629	7,024	2,126	390
NGL Line Diameter (Inch)	14.9	17.5	14.9	17.5
Pump for NGL Lines (1000 HP)	390	293	78	16
Gas Line Miles	8,348	25,896	1,670	1,439
Gas Line Diameter (Inch)	24.6	28.9	24.6	28.9
Compressor for Gas Lines (1000 HP)	3,367	7,041	673	391
Oil, Gas, and NGL Line Miles	34,594	41,104	6,919	2,284
Oil, Gas, and NGL Line Diameter (Inch)	20.4	26.9	20.4	26.9
Gathering and Processing				
Gas Gathering Line Miles	33,675	88,340	6,735	4,908
Gas Gathering Line Diameter (Inch)	6.4	7.9	6.4	7.9
Gas Gathering Line Compressor (1000 HP)	4,435	8,540	887	474
Oil Gathering Line Miles	25,846	50,612	5,169	2,812
Oil Gathering Line Diameter (Inch)	4.6	5.5	4.6	5.5
Oil & Gas Gathering Line Miles	59,521	138,952	11,904	7,720
Oil & Gas Gathering Line Diameter (Inch)	5.6	7.0	5.6	7.0
Refining and Oil Products Transport				
Oil Product Pipeline Miles	2,526	2,981	505	166
Oil Product Pipeline Diameter (Inch)	11.5	13.5	11.5	13.5
Oil Product Pipeline Pump (1000 HP)	447	528	89	29
Total				
Oil, Gas, NGL, and Oil Product Pipeline Miles	96,641	183,037	19,328	10,169
Oil, Gas, NGL, and Oil Product Pipeline Pump and Compression (1000 HP)	11,604	17,419	2,321	968

1 Introduction

1.1 Study Objectives

North America's energy business has transformed in the past decade thanks to technological advances allowing for the development of shale oil and natural gas resources. The shale revolution has renewed the focus on North America's oil and gas development, with U.S. and Canada oil production rising from roughly 11 million barrels per day in 2013 to over 13 million barrels per day in 2017, and natural gas production rising from about 83 billion to 91 billion cubic feet per day in the same period. This production growth has resulted in $316 billion of spending for new infrastructure to process, refine and transport that oil and gas during the past six years (**Exhibit 1**).

Exhibit 1: Infrastructure CAPEX during the Past Six Years, Million 2016$



Recent infrastructure capital expenditures (i.e., the CAPEX from 2013 through 2017) has averaged about $63 billion per year with a peak expenditure of over $74 billion in 2014. The industry's greatest spending was on new transmission pipelines which represents over one-third of the capital expenditure, averaging $23 billion per year. Surface equipment ranks second at an average annual CAPEX of roughly $21 billion in real terms. This category includes high-cost Gulf of Mexico offshore oil platforms. Onshore gathering and processing expenditures averaged about $13 billion per year in real terms. The remaining categories – oil and gas storage, refining enhancements and upgrades, products and rail transport, and export facilities – add roughly $6.5 billion per year to the total. In short, the industry has spent significantly on infrastructure development across several categories.

Despite robust growth in U.S. oil and gas production and infrastructure development, uncertainty remains about future growth. The relatively low oil and gas price environment over the past few years has reduced exploration and production (E&P) spending and activity, and infrastructure development has slowed from its peak in 2014. Thus, this study seeks to examine whether the drivers for strong infrastructure development remain and to project potential needs and impacts of infrastructure going forward despite uncertainty.

This study seeks to inform industry, policymakers and stakeholders about the dynamics of North America's energy markets based on a detailed supply/demand outlook for oil and gas development. The study assesses oil and gas infrastructure needed to support the delivery of crude oil and oil products, natural gas and natural gas liquids (NGLs). It also projects the associated economic benefits of infrastructure development, most notably Gross Domestic Product (GDP) and jobs impacts.

The study considers recent trends and uncertainties and investigates impacts of those trends on future infrastructure requirements with two scenarios: (1) an Escalating Unit Cost Case and (2) a Constant Unit Cost Case. These cases are briefly described below.

- The study's Escalating Unit Cost Case represents a reasonable set of expectations about the future that are consistent with recent market activity. In many ways, this case is the "status quo" case that reflects future cost growth consistent with recent trends.
- The study's Constant Unit Cost scenario depicts an environment in which the cost of building new infrastructure does not increase on a per unit basis. The base year of the Constant Unit Cost is 2017.

To develop the infrastructure investment requirements, the study includes the following components:

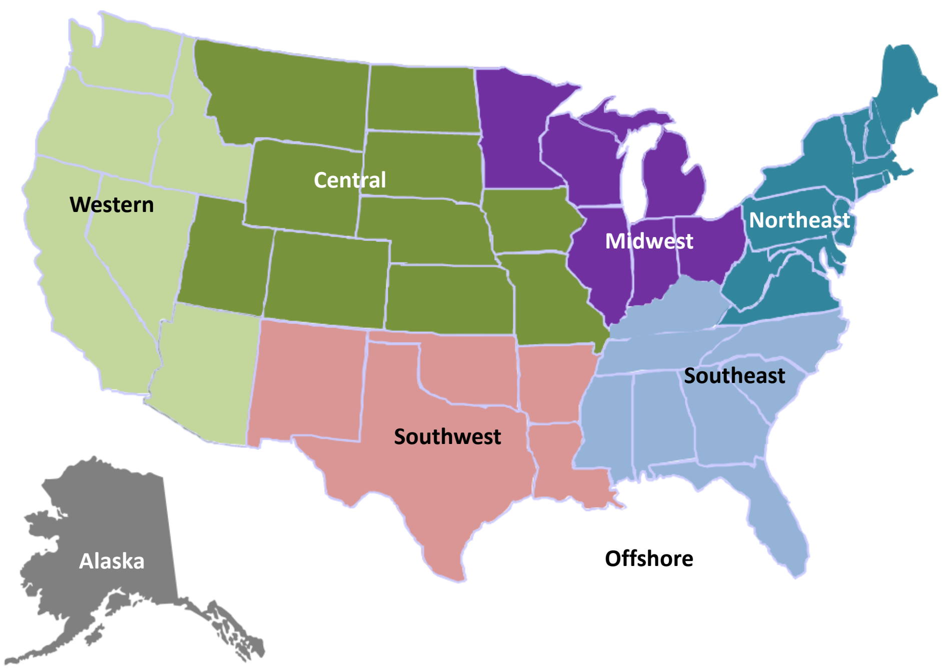
- Natural gas supply/demand projections that rely on the most current market trends.
- Projections for North American E&P activity.
- An assessment of onshore lease equipment, offshore production facilities, and gathering, processing, and fractionation needs to permit the delivery of hydrocarbons to a pipeline grid that supports delivery to refineries, markets, end-users and export terminals.
- Review of oil and gas storage requirements to temporarily store hydrocarbons until needed in markets and at refineries.
- Analysis of NGL and oil infrastructure requirements.
- An assessment of the increased oil, gas and NGL exports that could occur with increasing North American supplies.

The economic impact analysis that is discussed near the end of the report is based on IMPLAN modeling, which provides direct, indirect and induced job impacts of the oil and gas infrastructure development. The analysis also measures state-level employment and value-added impacts.

1.2 Study Regions

For reporting, this study applies U.S. DOE EIA pipeline regions for the Lower 48 states in the U.S. (**Exhibit 2**). The Northeast and Midwest study regions split Marcellus and Utica shale plays. A large amount of infrastructure development in the future is expected to be driven by significant gas and NGL production growth from this area. The Southwest, an area already with a large amount of oil and gas infrastructure and home too many producing basins, also should see significant growth.

Exhibit 2: Study Regions



1.3 Infrastructure Coverage

Exhibit 3 lists the infrastructure categories assessed in this study. The study applies a broad definition of infrastructure that includes all assets needed to process, refine, store and transport oil, gas, NGLs and oil products to end-users. End-users include industrial facilities that use oil, gas and NGLs as either a fuel or feedstock, petrochemical facilities, export terminals and distribution companies. This analysis excludes distribution infrastructure, which may see billions of dollars of capital expenditures for upgrades and enhancements to distribution systems.

Exhibit 3: Oil and Gas Infrastructure Categories

Category	Sub-Category	Type of Hydrocarbon
Surface and Lease Equipment	Onshore Lease Equipment	Oil and Gas
	Offshore Production Platforms	Oil
Gathering and Processing	Gas Gathering Lines	Gas
	Oil Gathering Lines	Oil
	Compressors	Gas
	Processing Plants	Gas
	Fractionation Facilities	NGL
Oil, Gas, and NGL Pipelines	Oil Pipelines	Oil
	Pumps for Oil Pipelines	Oil
	Gas Pipelines	Gas
	Compressor Stations for Gas Pipelines	Gas
	NGL Pipelines	NGL
	Pumps for NGL Pipelines	NGL
Oil and Gas Storage	Above Ground Tank Farms	Oil
	Underground Storage	Gas and NGL
Refining and Oil Products Transport	Refining	Oil
	Oil Product Pipelines	Oil
	Pumps for Oil Product Pipelines	Oil
	Rail Transport	Oil and NGL
Export Terminals	LNG Export Facilities	Gas
	NGL Export Terminals	NGL

The main infrastructure categories include surface and lease equipment; gathering and processing; oil, gas and NGL pipelines; oil and gas storage; refining and oil products transport; and export terminals. Each category is also split into sub-categories to provide additional detail. The sub-sub categories are allocated to gas, oil or NGL development to link the different activities with broader reporting by type of hydrocarbon.

Transmission pipelines include mainline capacity from supply areas to market areas and laterals on isolated segments that connect individual facilities or a cluster of facilities to a pipeline's mainline. Gas gathering pipe is the pipe that connects wells to a mainline or to a gas processing plant to extract the liquids and non-hydrocarbon gases. Oil gathering pipe collects and delivers crude oil from oil wells and lease condensate from gas wells to nearby crude oil storage and treatment tanks or to crude oil transmission mainlines. Surface and lease equipment for oil wells includes accessory equipment, the disposal system, electrification, flowlines, free water knockout units, heater treaters, LACT units, manifolds, producing separators, production pumping equipment, production pumps, production valves and mandrels, storage tanks and test separators. Surface and lease equipment for gas wells includes dehydrators, disposal pumps, electrification, flowlines and connections, the production package, production pumping equipment, production pumps and storage tanks.

Reported infrastructure development and the corresponding CAPEX only account for new capacity. Capital expenditures reported throughout the report are in 2016 dollars unless otherwise stated. They do not include operations and maintenance (O&M) costs, because O&M costs are not typically capitalized. Costs associated with O&M could add billions of dollars to the total expenditures reported herein and would account for a significant number of jobs beyond the employment levels reported in Section 6.

1.4 Report Structure

The remainder of this report contains the following information:

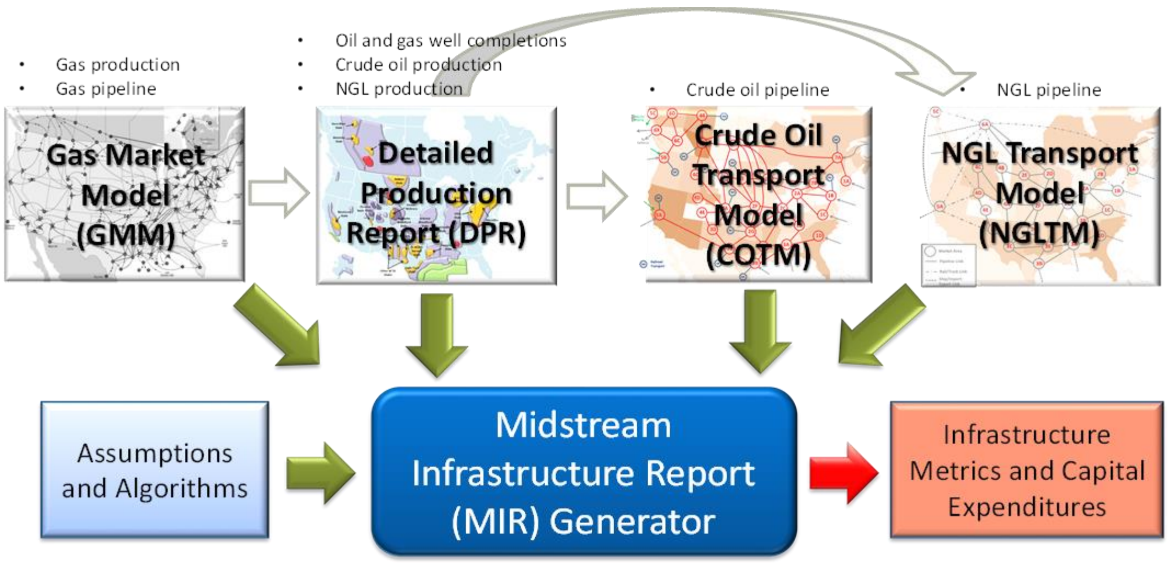
- Section 2 provides an overview of the modeling methodology.
- Section 3 summarizes the scenarios applied in this study, presenting the trends for oil and gas production and demand, and examining market dynamics for gas, NGL, and oil transport.
- Section 4 provides the results for oil and gas infrastructure development. The section starts off with an overview, followed by a detailed discussion that examines infrastructure development in the two scenarios for each of the infrastructure categories. The section ends with a discussion about regional development.
- Section 5 provides results of the economic impact analysis to assess the jobs and GDP impacts of infrastructure development.
- Section 6 lists key findings for the study.
- Appendix A discusses the ICF modeling tools applied to complete this analysis.
- Appendix B provides details for infrastructure development, including all key statistics that drive infrastructure investment.
- Appendix C provides capital expenditures by region.
- Appendix D provides the approximate economic impacts of the pipeline and gathering CAPEX.
- Appendix E illustrates the regional natural gas demand and oil, gas and NGL production.
- Appendix F provides additional charts, graphs and data tables developed for this study and used to support the conclusions.

2 Methodology

2.1 Modeling Framework

This study determines oil and gas infrastructure development and capital expenditure requirements based on ICF's Midstream Infrastructure Report (MIR) process, shown in **Exhibit 4**. ICF's MIR uses four proprietary modeling tools, namely ICF's Gas Market Model (GMM), the Detailed Production Report (DPR), a Natural Gas Liquids (NGL) Transport Model (NGLTM) and a Crude Oil Transport Model (COTM). Appendix A has detailed descriptions of these modeling tools.

Exhibit 4: Modeling Tools for ICF's Midstream Infrastructure Report



The GMM, a full supply-demand equilibrium model of the North American gas market, is a widely used model applied to assess North American gas supply, demand, transport and prices. It determines natural gas prices, production and demand by sector and region. The GMM projects gas transmission capacity development, based on gas market and supply dynamics.

ICF's DPR, a vintage production model, estimates the number of oil and gas well completions and well recoveries based on levels of gas production, that the GMM calculates and projects oil and gas prices, gas-directed versus oil-directed drilling, and well productivity. The model estimates crude oil and NGLs production for over 50 regions, based on assumed liquids-to-gas ratios.

ICF's NGLTM and COTM evaluate NGL and crude oil transport requirements to estimate pipeline capacity requirements. The models rely on regional NGL and crude oil production from the DPR, and consider pipelines, railways, trucking routes and marine channels as means of transporting raw (y-mix) and purity NGLs and crude oil from production areas to refineries, export terminals, and processing and industrial facilities that use the hydrocarbons either as a fuel or feedstock. The model estimates refinery enhancements and output as well as oil product transport and crude oil and oil products exports.

2.2 Infrastructure Methodology and Criteria

ICF's MIR projects natural gas, NGL and crude oil infrastructure requirements by considering:

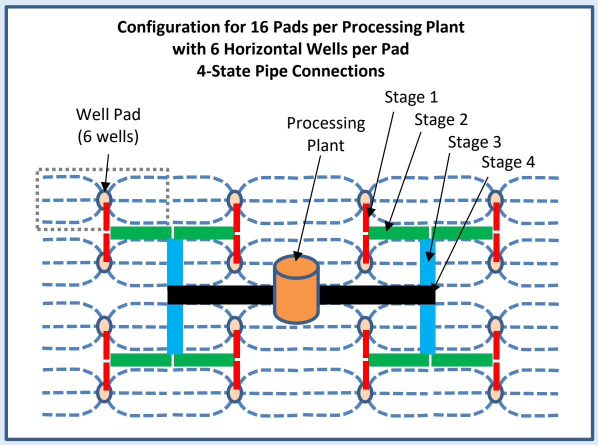
- Regional natural gas supply-demand growth based on scenario market trends;
- Well completions and production by region;
- Gas processing and NGL fractionation requirements;
- Changes in power plant gas use;
- Regional underground and above ground natural gas storage needs;
- Changes in transportation of natural gas, NGL, and oil brought on by regional supply-demand balances, changing market forces and world trade of raw and refined energy products.

2.2.1 Estimating the Amount of Infrastructure Development

Exhibit 5 lists the criteria applied to estimate new infrastructure development and the capital expenditures associated with it. Near-term infrastructure development includes projects that are currently under construction or are sufficiently advanced in the development process. Unplanned projects are also included in the projection when the market signals need of new capacity.

The infrastructure assessment includes surface and lease equipment, offshore platforms, gathering, processing, and fractionation projects. Natural gas transport capability adds to the infrastructure stack based on projections from the GMM. Supply growth and market evolution within and across geographic areas create the base for the decision to add pipeline capacity. Included are projects that are currently under development (including projects characterized as new pipeline, expansion projects, repurposing projects and reversals of pipelines), as well as unplanned or "generic" projects. If unknown for a specific project, the project's pipeline mileage and compression calculations use rule-of-thumb estimates based on historical capacity expansion data along various pipeline corridors.

Exhibit 5: Criteria for New Infrastructure Development

Metric	Criteria
Gas gathering line miles per well (for gathering gas both from gas wells and oil wells)	Gathering line mileage requirements calculations assume the number of wells per pad and number of pads per processing plant. The configuration below is an example of a system with 16 pads per processing plant, six horizontal wells per pad, and 120 acres well spacing. This configuration requires a total of about 0.24 miles of gathering line per well with a combination of four different pipe sizes. 
Share of new wells that are pad drilled	The share of new wells that are pad drilled was only about 5 percent in 2006, growing rapidly to almost 60 percent by 2013 and is assumed to reach over 90 percent by 2035.
Average number of wells per pad	The average four wells per pad in 2010 is assumed to increase to 18 wells per pad by 2035. An increasing number of wells per pad will reduce the total mileage but increase the average diameter for gathering pipelines.
Oil gathering line miles per oil well (only applies to high-productivity wells)	0.25 miles/well for four-well pads and 0.125 miles/wells for eight-well pads. High productivity oil well is defined as wells with EUR greater than 30,000 barrels.
Gas gathering line compression requirement	141 horsepower for every 1 million cubic feet per day of production.
Portion of gas production growth that requires new processing capacity	Average of 60 percent; varies by play and region.

Criteria for New Infrastructure Development (Continued)

Metric	Criteria
Gas processing plant size	Between 25 and 600 million cubic feet per day, yielding an average of 275 million cubic feet per day for all production; varies by play.
Gas laterals for processing plant	Average 20 miles per plant.
Gas lateral diameters for processing plant	Between 10 to 30 inches estimated by using the size of the plant.
Gas power plant capacity	If unknown, the average power plant size for combined cycle plants is assumed to be 500 Megawatts (MW). Combustion turbine capacity can range up to 500 MW.
Gas laterals for gas power plants	15 miles per power plant.
Gas lateral diameter for gas power plant	24 inches for combined cycles. Diameter for small power plants is calculated using Panhandle Equation assuming a heat rate of 8,000 Btu/kWh (to estimate gas throughput).
Gas storage capacity	5 billion cubic feet of incremental working gas capacity for every 1 billion cubic feet per day of LNG export capacity added after 2020. 1 billion cubic feet of incremental working gas capacity for every 1 Gigawatt of incremental gas-fired generating capacity added after 2020.
Compression requirements for gas storage fields	1,880 horsepower per billion cubic feet of working gas capacity for salt cavern storage. 610 horsepower per billion cubic feet of working gas capacity for depleted reservoir storage. 1,200 horsepower per billion cubic feet of working gas capacity for aquifer reservoir storage.

Criteria for New Infrastructure Development (Continued)

Metric	Criteria
Portion of NGL production growth that requires new fractionation capacity	Average of 85 percent, varies by play and region.
NGL Fractionation Plant Size	Between 25,000 and 500,000 barrels per day, yielding an average of 75,000 barrels per day for all production; varies by play and region.
NGL Laterals for Fractionation and Petrochemical Facilities	Average 50 miles per 100,000 barrels per day of NGLs.
NGL lateral diameter	Average 14 inches.
Crude oil storage tank capacity	Average of 5,000 barrels per tank.
Crude oil storage tank farm size	Average of 750 tanks per farm.
Crude oil tank farm laterals	Average 20 miles per tank farm with diameters ranging between 12 and 24 inches.
Oil product pipeline miles	Average of 1.3 miles per 1,000 barrels per day of incremental refinery output.
Oil product pipeline diameter	Average of 15 inches, varies by PADD.
Pumping requirements for crude oil and oil product pipelines	Average of 177 horsepower per mile of pipeline.

Oil and gas lease equipment and offshore platform requirements calculations use data on incremental well completions and the expected oil, gas and NGL production from the wells. This analysis does not provide detailed measures or metrics for lease equipment such as miles of flowlines and connections, number of dehydrators, storage tanks, disposal systems, separators, etc. Expenditures for incremental lease equipment, as discussed in Section 4, are directly proportional to the number of well completions.

The report includes estimates of incremental capacity for offshore platforms for incremental oil, gas and NGL production as a barrel of oil equivalent (BOE) rate based on new offshore well completions.

Computations for the mileage for gas gathering lines considers well spacing and configuration, the number of wells in multi-well pad configuration, and the number of pads per processing plant. The core calculations assume a certain amount of gathering line mileage per well. Estimates for compression requirements for gas gathering lines rely on production levels and by assuming a pre-defined horsepower-to-production ratio, estimated from historical data.

Gas processing plant capacity assumes that a portion of the production growth requires new processing capacity. The estimated number of processing plants needed relies on the required total incremental processing capacity and assumes an average plant size for each geographic area. Calculations for pipeline lateral requirements for connecting processing plants with pipeline mainlines rely on the number of new plants required, with an assumed mileage for each lateral. The estimated diameter of the laterals relies on the size of the gas processing plants in a geographic area.

The number of unplanned gas-fired power plants develops by considering the growth of gas-fired power generation. Applying the total incremental gas power plant capacity helps to estimate the number of new gas power plants built in each geographic area, based on assumed plant sizes. The required lateral pipeline mileage is then calculated using an assumed mileage per plant. The estimated diameter for the laterals relies on the required throughput for each plant, calculated based on each plant's heat rate.

In response to LNG and power plant additions, new gas storage assets develop. Lateral mileage, sizing and compression needed to connect gas storage develops based on the amount of storage capacity added.

NGL pipeline capacity develops based on supply development, North American market growth, and export activity. Infrastructure tallies include announced NGL pipeline projects that are under construction or deemed far enough along in the development process to see completion. This includes NGL raw-mix pipelines and pipelines built to transport a single liquid (for example, ethane or propane) or a mix of condensate products (for example, pentanes-plus) used as a diluent for oil transport.

Additionally, the NGL pipeline capacity includes new NGL pipeline projects to support future supply development and market growth. NGLs produced in relatively constrained areas require new pipelines to foster transport of the liquids to market areas or export facilities. If unknown, pipeline mileage for new capacity estimates rely on the distance between geographic areas, and the size of the pipeline and pumping requirements consider expected throughput.

NGL lateral mileage from gas processing and fractionation facilities to an NGL transmission line is calculated based on the amount of NGLs processed (i.e., removed from the gas stream). Lateral mileage and the diameter of each lateral estimates rely on an assumed number of miles per volume of NGLs processed and based on an average processing-fractionation plant size.

Incremental NGL fractionation capacity estimations rely on NGL supply development and market growth. NGL export capacity is scenario-dependent, based on supply development and market activity.

Required oil gathering line connections arise only for high-productivity oil wells. Wells with low productivity do not require gathering lines, as local tank storage and field trucking handles oil production. An assumed "cutoff" for estimated ultimate recovery (EUR) per well helps to separate high and low productivity wells. Oil gathering line mileage is then derived based on the number of wells per drill site, if an average mileage of gathering line needed for each high-productivity well.

The need for crude oil transmission capacity derives from supply development and import/export activity. The study considers rail and trucking of oil as transport options. The pipeline stack includes announced pipeline projects. If unknown for a project, pipeline mileage estimates based on the distance between the relevant geographic areas for each project are used. The study estimates sizing of a pipeline and pumping requirements based on throughput.

Additions of crude oil storage rely on oil production growth within geographic areas. The number of crude oil tanks develops from the required storage capacity for fields, assuming an average tank size. The required number of tank farms develops based on an average number of storage tanks per tank farm. The lateral mileage for oil storage capacity estimations derive from assumptions of required needed miles of lateral per tank farm.

As mentioned above, this study accounts for crude oil transport by rails. Thus, planned rail cars and loading and unloading terminal capacity additions make up part of the infrastructure stack. However, the study does not include unplanned rail car and terminal loading/unloading capacity, as incremental pipeline capacity equates as a more cost-effective option for unplanned capacity, especially when the capacity requirement is significant.

Included are planned crude oil refinery capacity additions and enhancements. The study includes changes to refineries only in this category because it is difficult to distinguish between "new" capacity and enhancements and upgrades to existing capacity.

Need for crude product pipeline relies on growth in refinery output. Supply changes and market growth influence the estimations of refinery output. New crude product pipeline miles calculations rely on the miles needed per unit volume growth of refinery output as calculated from historical data. The assumed diameter of the pipeline derives from on the average diameter for existing pipelines. Historical horsepower per mile of pipeline statistics serve as the base for estimated pumping requirements.

2.2.2 Estimating Capital Requirements for Oil and Gas Infrastructure Development

Historical unit costs of pipeline and compressor construction rely on Oil & Gas Journal survey of U.S. pipeline and compressor station projects completed between 1980 through June 2017. Since the cost data for 2017 is not complete, a regression of the historical data estimates average cost for 2017.

The unit cost for pipeline construction has risen significantly in recent years. This illustrates the change by comparing the regressed 2017 cost to the predicted value for the year 2017 in the 2016 INGAA Foundation study. The average U.S. pipeline unit cost in 2017 was about $230,000 (in 2016 dollars) per inch-mile, varying regionally. In the 2016 INGAA Foundation Study, the predicted average U.S. pipeline unit cost in 2017 was $158,000 per inch-mile. By contrast, the cost of compression tracked closely with the previous study with the U.S. average unit cost for compressor station construction in 2017 is $3,100 per HP, varying by region, compared with $3,000 in the 2016 INGAA Study.

In the Constant Unit Cost scenario, the study assumes the unit costs for all assets remain constant in real terms throughout the projection. The base year for the Constant Unit Cost scenario is 2017.

In the Escalating Unit Cost scenario, the unit costs rise in real terms in the projection. Included are the escalation of the unit costs for pipeline and compressor station construction determinations based on regression of the historical unit costs with natural gas production growth. The regression was done by region because the unit costs are very different across regions; for example, costs are relatively high in the Northeast, where projects have been very difficult and time-consuming to construct due to congested corridors and rough terrain, but much lower in the South-Central region, which has generally been in open, rural corridors friendlier to infrastructure development. The construction costs for pipeline and compressor stations shown in **Exhibit 6** and **Exhibit 7**, respectively.

The study assumes the unit costs for other type of assets (surface and lease equipment, offshore production platforms, gathering, processing, etc.) remain constant in real terms in the projection in the Constant Unit Cost scenario and escalate at the same average rate of the unit cost for pipelines and compressor stations in the Escalating Unit Cost scenario.

Exhibit 6: Pipeline Construction Cost (2016$ per Inch-Mile) for the Escalating Unit Cost Case

	Year	U.S.	New England	Northeast (NY, NJ)	Pennsyl-vania	Mid Atlantic	Southeast	Florida	Midwest	South Central	Central/ Mountain	Pacific Northwest	California
Historical Data	2000	$65,595	$217,511	$119,003		$55,733	$77,425	$80,612		$25,301	$36,241	$67,079	$61,394
	2001	$55,440		$95,831	$84,677	$51,902	$64,427	$162,841	$68,477		$49,466	$69,644	$46,447
	2002	$58,304	$524,223	$67,205	$86,858	$71,357	$71,632	$409,681	$57,410	$77,896	$34,037	$1,587,181	
	2003	$81,100	$323,536		$92,961	$495,625	$87,524		$121,235	$62,066	$52,727	$203,125	
	2004	$87,788	$415,355	$170,167	$84,684	$109,700	$106,618	$119,339	$90,239	$109,592	$45,452	$122,893	$55,582
	2005	$66,730	$253,797	$94,846	$134,334	$84,809	$74,679	$107,266	$102,164	$59,459	$56,779		$73,688
	2006	$84,788					$78,354		$80,301	$89,561	$61,827		
	2007	$109,156	$405,818	$620,070	$209,985		$67,299			$68,619	$77,145	$154,274	
	2008	$68,083	$321,385	$422,668	$108,217	$217,086	$127,593		$146,625		$75,375	$101,829	
	2009	$148,422	$134,468		$131,043		$179,172			$126,625	$246,653		
	2010	$111,656	$750,271		$156,318					$110,587	$84,744		
	2011	$118,999			$149,573		$112,103		$143,415	$101,194	$84,370	$129,284	
	2012	$142,914		$414,225	$133,296		$95,079	$465,039		$117,123	$115,586		$308,531
	2013	$218,603	$573,689	$390,662	$207,304	$369,964	$10,026	$227,427	$161,773	$219,281	$132,678	$170,160	$238,668
	2014	$130,068			$193,247	$266,028	$94,326	$1,155,413		$114,372	$89,964		$403,035
	2015	$221,713		$568,032	$175,283	$103,617	$279,170		$172,225		$108,407	$118,454	
	2016	$356,149	$629,279	$663,910	$222,300	$253,541	$188,611			$156,952	$199,288		
Projection	2017	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2018	$240,053	$680,754	$620,588	$203,770	$257,495	$164,654	$305,894	$183,457	$167,615	$142,947	$193,824	$422,666
	2019	$250,397	$701,498	$646,526	$209,418	$266,932	$169,806	$316,449	$188,943	$173,287	$148,513	$200,516	$445,068
	2020	$260,742	$722,242	$672,464	$215,065	$276,369	$174,958	$327,005	$194,429	$178,959	$154,080	$207,208	$467,471
	2021	$271,087	$742,986	$698,402	$220,713	$285,806	$180,109	$337,560	$199,915	$184,631	$159,646	$213,900	$489,873
	2022	$281,432	$763,730	$724,340	$226,360	$295,242	$185,261	$348,116	$205,402	$190,303	$165,212	$220,592	$512,275
	2023	$291,776	$784,473	$750,278	$232,008	$304,679	$190,413	$358,672	$210,888	$195,975	$170,779	$227,284	$534,677
	2024	$302,121	$805,217	$776,215	$237,655	$314,116	$195,564	$369,227	$216,374	$201,647	$176,345	$233,976	$557,079
	2025	$312,466	$825,961	$802,153	$243,303	$323,553	$200,716	$379,783	$221,860	$207,319	$181,911	$240,668	$579,482
	2026	$322,811	$846,705	$828,091	$248,951	$332,990	$205,868	$390,339	$227,346	$212,991	$187,478	$247,360	$601,884
	2027	$331,405	$863,938	$849,639	$253,642	$340,830	$210,148	$399,108	$231,904	$217,703	$192,102	$252,919	$620,494
	2028	$338,099	$877,361	$866,423	$257,297	$346,936	$213,481	$405,938	$235,454	$221,373	$195,704	$257,249	$634,990
	2029	$341,937	$885,057	$876,046	$259,392	$350,438	$215,393	$409,854	$237,490	$223,478	$197,769	$259,732	$643,302
	2030	$347,151	$895,513	$889,120	$262,239	$355,194	$217,989	$415,175	$240,255	$226,337	$200,575	$263,105	$654,593
	2031	$350,299	$901,826	$897,014	$263,957	$358,066	$219,557	$418,388	$241,925	$228,063	$202,269	$265,142	$661,411
	2032	$354,577	$910,403	$907,739	$266,293	$361,968	$221,687	$422,752	$244,193	$230,408	$204,570	$267,909	$670,675
	2033	$357,183	$915,630	$914,275	$267,716	$364,346	$222,985	$425,412	$245,576	$231,838	$205,973	$269,595	$676,319
	2034	$361,288	$923,860	$924,566	$269,956	$368,090	$225,029	$429,600	$247,752	$234,088	$208,181	$272,250	$685,208
	2035	$364,232	$929,764	$931,948	$271,564	$370,776	$226,496	$432,604	$249,314	$235,702	$209,766	$274,155	$691,583

Exhibit 7: Compressor Station Construction Cost (2016$ per Horsepower) for the Escalating Unit Cost Case

	Year	U.S.	New England	Northeast (NY, NJ)	Pennsyl-vania	Mid Atlantic	Southeast	Florida	Midwest	South Central	Central/ Mountain	Pacific Northwest	California
Historical Data	2000	$1,866		$2,722			$2,125	$1,544	$1,754		$2,402		$2,402
	2001	$1,840	$1,948			$1,542	$1,704	$1,516		$2,896	$2,323	$1,500	$1,970
	2002	$1,788	$3,185	$1,914		$1,440	$1,746	$2,420	$2,429	$1,531	$1,583	$2,170	$1,874
	2003	$1,833		$1,828		$2,911	$1,799		$3,055	$1,891	$1,352		$1,432
	2004	$1,988							$2,818	$2,095	$1,756		$1,998
	2005	$2,135		$2,346		$1,445	$2,393	$2,413	$1,673	$1,643	$2,367		$2,659
	2006	$1,986	$3,237	$2,486			$2,261	$2,132	$1,840	$1,535	$1,313		$1,520
	2007	$1,711					$2,504	$1,597	$1,422	$1,929	$1,551		$1,843
	2008	$2,132		$3,185		$5,758	$2,668		$3,101	$1,781	$1,894	$2,116	$2,481
	2009	$2,112		$2,435	$5,810	$2,235	$4,277	$2,331		$2,618	$1,668	$3,196	$2,158
	2010	$2,857						$3,597		$2,378	$4,057		$5,015
	2011	$2,669		$3,088	$1,613	$5,196			$3,282	$2,026	$4,191		$5,287
	2012	$2,776		$2,050	$2,987	$4,211	$3,283			$2,487	$3,732	$2,899	$3,289
	2013	$3,022	$4,097	$3,453	$3,011	$6,831	$3,463	$3,252	$4,933	$2,935	$3,745	$3,114	$3,343
	2014	$3,001		$3,102	$2,972	$5,196	$2,996				$3,674		$4,882
	2015	$2,913		$2,704	$2,721	$3,115	$4,430	$3,998	$3,322				
	2016	$2,958	$4,003	$4,721	$3,197	$6,116	$2,974		$1,913	$2,646			
Projection	2017	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2018	$3,243	$4,384	$3,561	$3,230	$5,874	$3,922	$4,185	$3,479	$2,939	$4,919	$3,782	$6,138
	2019	$3,394	$4,563	$3,703	$3,429	$6,258	$4,115	$4,438	$3,612	$3,056	$5,276	$3,984	$6,602
	2020	$3,545	$4,742	$3,844	$3,629	$6,642	$4,309	$4,691	$3,744	$3,172	$5,633	$4,185	$7,065
	2021	$3,696	$4,921	$3,986	$3,828	$7,027	$4,502	$4,944	$3,876	$3,288	$5,990	$4,387	$7,528
	2022	$3,847	$5,100	$4,128	$4,028	$7,411	$4,695	$5,197	$4,008	$3,405	$6,347	$4,589	$7,991
	2023	$3,998	$5,278	$4,269	$4,227	$7,795	$4,889	$5,450	$4,141	$3,521	$6,704	$4,790	$8,454
	2024	$4,149	$5,457	$4,411	$4,427	$8,180	$5,082	$5,704	$4,273	$3,638	$7,060	$4,992	$8,917
	2025	$4,300	$5,636	$4,553	$4,626	$8,564	$5,275	$5,957	$4,405	$3,754	$7,417	$5,194	$9,380
	2026	$4,451	$5,815	$4,694	$4,826	$8,949	$5,469	$6,210	$4,537	$3,871	$7,774	$5,395	$9,844
	2027	$4,576	$5,964	$4,812	$4,992	$9,268	$5,629	$6,420	$4,647	$3,967	$8,071	$5,563	$10,228
	2028	$4,674	$6,080	$4,904	$5,121	$9,517	$5,754	$6,584	$4,733	$4,043	$8,302	$5,693	$10,528
	2029	$4,730	$6,146	$4,956	$5,195	$9,659	$5,826	$6,678	$4,782	$4,086	$8,434	$5,768	$10,700
	2030	$4,806	$6,236	$5,028	$5,295	$9,853	$5,924	$6,805	$4,849	$4,144	$8,614	$5,870	$10,933
	2031	$4,852	$6,291	$5,071	$5,356	$9,970	$5,982	$6,883	$4,889	$4,180	$8,723	$5,931	$11,074
	2032	$4,914	$6,365	$5,129	$5,439	$10,129	$6,062	$6,987	$4,944	$4,228	$8,870	$6,014	$11,266
	2033	$4,953	$6,410	$5,165	$5,489	$10,226	$6,111	$7,051	$4,977	$4,257	$8,960	$6,065	$11,382
	2034	$5,012	$6,481	$5,221	$5,568	$10,378	$6,188	$7,151	$5,029	$4,303	$9,102	$6,145	$11,566
	2035	$5,055	$6,531	$5,262	$5,625	$10,488	$6,243	$7,223	$5,067	$4,337	$9,204	$6,203	$11,698

Smaller-diameter pipes used in gathering systems have lower unit costs that vary by diameter. As shown in **Exhibit 8**, gathering line costs for pipes between 2 and 22 inches in diameter range from $29,000 to $167,000 per inch-mile in 2017, well below the average inch-mile cost of the larger-diameter transmission pipelines discussed above. The study assumes the costs for larger diameter gathering line are equal to the U.S. average cost for the transmission pipeline.

Exhibit 8: Gathering Pipeline Cost (2016$ per Inch-Mile) for the Escalating Unit Cost Case

Year	Diameter (Inches)														
	2"	4"	6"	8"	10"	12"	14"	16"	18"	20"	22"	24"	26"	28"	30"
2010	$35,065	$29,221	$23,754	$24,131	$36,762	$62,212	$96,146	$100,388	$103,205	$106,022	$108,839	$111,656	$111,656	$111,656	$111,656
2011	$35,464	$29,553	$24,381	$25,120	$38,789	$66,495	$105,283	$113,595	$114,946	$116,297	$117,648	$118,999	$118,999	$118,999	$118,999
2012	$35,911	$29,926	$25,029	$26,117	$40,808	$70,733	$114,261	$126,503	$130,606	$134,708	$138,811	$142,914	$142,914	$142,914	$142,914
2013	$39,341	$32,784	$27,419	$28,611	$44,705	$77,489	$125,174	$138,586	$158,590	$178,595	$198,599	$218,603	$218,603	$218,603	$218,603
2014	$41,304	$34,420	$28,788	$30,040	$46,937	$81,357	$131,423	$145,504	$145,504	$145,504	$145,504	$145,504	$145,504	$145,504	$145,504
2015	$43,493	$36,244	$30,313	$31,631	$49,424	$85,668	$138,387	$153,214	$170,339	$187,464	$204,588	$221,713	$221,713	$221,713	$221,713
2016	$45,522	$37,935	$31,728	$33,107	$51,730	$89,665	$144,843	$160,362	$209,309	$258,256	$307,202	$356,149	$356,149	$356,149	$356,149
2017	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2018	$30,683	$25,569	$21,385	$22,315	$34,867	$60,436	$97,628	$108,088	$141,079	$174,070	$207,061	$240,053	$240,053	$240,053	$240,053
2019	$32,005	$26,671	$22,307	$23,277	$36,370	$63,041	$101,835	$112,746	$147,159	$181,571	$215,984	$250,397	$250,397	$250,397	$250,397
2020	$33,327	$27,773	$23,228	$24,238	$37,872	$65,645	$106,042	$117,404	$153,238	$189,073	$224,907	$260,742	$260,742	$260,742	$260,742
2021	$34,650	$28,875	$24,150	$25,200	$39,375	$68,249	$110,249	$122,061	$159,318	$196,574	$233,831	$271,087	$271,087	$271,087	$271,087
2022	$35,972	$29,977	$25,071	$26,161	$40,877	$70,854	$114,456	$126,719	$165,397	$204,076	$242,754	$281,432	$281,432	$281,432	$281,432
2023	$37,294	$31,078	$25,993	$27,123	$42,380	$73,458	$118,663	$131,377	$171,477	$211,577	$251,677	$291,776	$291,776	$291,776	$291,776
2024	$38,616	$32,180	$26,914	$28,085	$43,882	$76,063	$122,870	$136,035	$177,557	$219,078	$260,600	$302,121	$302,121	$302,121	$302,121
2025	$39,939	$33,282	$27,836	$29,046	$45,385	$78,667	$127,078	$140,693	$183,636	$226,580	$269,523	$312,466	$312,466	$312,466	$312,466
2026	$41,261	$34,384	$28,758	$30,008	$46,887	$81,272	$131,285	$145,351	$189,716	$234,081	$278,446	$322,811	$322,811	$322,811	$322,811
2027	$42,359	$35,299	$29,523	$30,807	$48,136	$83,435	$134,780	$149,221	$194,767	$240,313	$285,859	$331,405	$331,405	$331,405	$331,405
2028	$43,215	$36,012	$30,120	$31,429	$49,108	$85,120	$137,502	$152,235	$198,701	$245,167	$291,633	$338,099	$338,099	$338,099	$338,099
2029	$43,706	$36,421	$30,461	$31,786	$49,665	$86,087	$139,063	$153,963	$200,956	$247,950	$294,943	$341,937	$341,937	$341,937	$341,937
2030	$44,372	$36,977	$30,926	$32,271	$50,423	$87,399	$141,184	$156,311	$204,021	$251,731	$299,441	$347,151	$347,151	$347,151	$347,151
2031	$44,774	$37,312	$31,206	$32,563	$50,880	$88,192	$142,464	$157,728	$205,871	$254,014	$302,157	$350,299	$350,299	$350,299	$350,299
2032	$45,321	$37,768	$31,587	$32,961	$51,501	$89,269	$144,204	$159,654	$208,385	$257,115	$305,846	$354,577	$354,577	$354,577	$354,577
2033	$45,654	$38,045	$31,820	$33,203	$51,880	$89,925	$145,264	$160,828	$209,917	$259,006	$308,095	$357,183	$357,183	$357,183	$357,183
2034	$46,179	$38,482	$32,185	$33,585	$52,476	$90,959	$146,933	$162,676	$212,329	$261,982	$311,635	$361,288	$361,288	$361,288	$361,288
2035	$46,555	$38,796	$32,448	$33,858	$52,904	$91,700	$148,130	$164,002	$214,059	$264,117	$314,174	$364,232	$364,232	$364,232	$364,232

The study estimates lease equipment costs based on EIA Oil and Gas Lease Equipment and Operating Cost data, with cost adjustments from on the Producer Price Index Industry Data from the Bureau of Labor Statistics. Costs average $82,500 per gas well and $202,000 per oil well. Oil and gas offshore platform costs rely on historical expenditure information provided by various sources. Offshore developments apply average platform costs of $23,500 per barrel of oil equivalent.

Exhibit 9 shows gas storage field costs. Costs vary depending on the type of underground storage field (i.e., salt cavern, depleted reservoir, or aquifer storage) with an average of $35 million per billion cubic feet of working gas capacity applied for new projects and $29 million per billion cubic feet of working gas capacity applied for expansion projects.

Exhibit 9: Natural Gas Storage Costs in 2017 (Million$ per Billion Cubic Feet of Working Gas Capacity)

Field Type	Expansion	New
Salt Cavern	$32	$38
Depleted Reservoir	$19	$22
Aquifer	$37	$45

Other unit costs for remaining types of assets as estimated from various sources and the unit costs for 2017 are as follows:

- Gas processing costs (not including compression) are about $635,000 per million cubic feet per day of processed capacity. Compression requirements for gas processing plants are 100 horsepower per million cubic feet per day of capacity, and the costs associated with it add to the cost of capacity directly above.
- Costs for NGL fractionation facilities average about $6,300 per barrel of oil equivalent (BOE) per day of processed NGLs.
- Costs for NGL export facilities are purity dependent, averaging about $6,000 per barrel of oil equivalent (BOE) per day of ethane, about $4,850 per BOE per day for propane and butane.
- Costs of LNG export facilities, as identified in U.S. Department of Energy export applications and other publicly available sources, average $5 billion to $6 billion per billion cubic feet per day of export capacity.
- The unit cost for crude oil storage tanks assumed to be about $15 per barrel of oil.
- The unit cost for crude oil refining capacity expansion is about $12,000 per BOE per day.

As mentioned above, the study assumes the unit cost projection for these assets to remain constant in real terms in the projection in the Constant Unit Cost scenario and to escalate at the same average rate of the unit cost for pipelines and compressor stations in the Escalating Unit Cost scenario.

3 Scenario Overview

3.1 Defining the Study's Scenarios

Oil and gas markets are uncertain because of relatively low commodity prices currently hampering supply development. In late 2015, crude oil prices declined precipitously, mainly because of a supply glut brought about by reduced growth in global markets. According to the U.S. Department of Energy's Energy Information Administration, U.S. crude oil production increased significantly into 2015, with production peaking at over 9 million barrels per day. The increase came almost entirely from development of tight oil and shale plays. The growth reduced U.S. crude oil imports and contributed to a significant supply overhang in global markets, adding to record crude oil inventory levels.

At the same time, natural gas and NGL prices declined in response to robust gas supply growth occurring from shale resources. The mild winter of 2015-16 created a U.S. natural gas storage overhang that further reduced prices, and natural gas at Henry Hub fell to under $2 per MMBtu by March 2016.

The low commodity price environment has slowed E&P activity and arrested the supply increases that had been occurring before 2016. Slowing supply growth has resulted in reduced infrastructure development, creating a cloud of uncertainty for future oil and gas infrastructure growth. While the future remains uncertain, the environment remains positive for oil and gas development in the longer term.

Several factors should increase supply and motivate infrastructure development. Notably, the North American shale and tight oil and gas resource base is enormous, with a large amount of relatively low-cost oil and gas remaining to be developed. The application of technology is continuing to reduce drilling costs and enhance well productivity. Thus, the unit cost of oil and gas production continues to decline.

In addition to the productivity gains and cost reductions, markets appear poised for growth. Indeed, refinery input and output has increased during the past few years as North American oil production creates renewed interest in refinery investments to increase product output. Natural gas exports are on the cusp of growing significantly, both to Mexico and to markets around the globe. Further, low gas prices have fostered growth in the power generation market as coal plants continue to retire across the U.S. This trend seems irreversible in light of regulations that encourage clean power. However, it is worth noting that while the scenarios include currently enacted environmental regulations and regional efforts to control carbon emissions, they do not include any federal programs aimed at carbon emissions, such as the Clean Power Plan. Nevertheless, the relatively low gas price environment generally discourages additional investment to upgrade or further limit emissions from coal plants, especially considering that the threat of federal carbon control still looms on the horizon. Petrochemical facilities appear poised for a resurgence, as supply development continues to put downward pressure on natural gas and NGL prices.

This study foresees a dynamic natural gas resource base and growth across a number of markets (**Exhibit 10**). Most notably, refinery input continues to increase, albeit relatively modestly, and continued tight oil supply development in the U.S. and incremental imports from Canada modestly reduce near-term crude imports from overseas, consistent with recent trends. Natural gas markets grow to meet stronger demand at petrochemical facilities and in the power sector, where coal plants continue to retire and some nuclear plants see retirement at the end of their 60-year life. LNG and Mexican exports of natural gas also rise significantly over time, consistent with recent trends. For NGL, both domestic ethylene and polypropylene production increase along with exports. The sustained market growth projected in the scenario relies supply development that occurs at reasonable prices. This study assumes West Texas Intermediate crude oil prices are $75 by 2025 and remain constant thereafter while the Henry Hub price averages a little over $3 per MMBtu through 2035.

The unit cost for pipeline construction has risen significantly in recent years. The average U.S. pipeline unit cost in 2017 was about $230,000 (in 2016 dollars) per inch-mile, varying regionally. In the 2016 INGAA Study, the projected average U.S. pipeline unit cost in 2017 was $158,000 per inch-mile.

This study analyzed two different trends for unit costs over time to assess the uncertainty of costs and investigate the impacts on future capital expenditures. Factors affecting unit cost of infrastructure development include project delays, difficulty of permitting and approvals, and cost of raw materials and labor. The high degree of uncertainty with project development makes it difficult to foresee a single set of assumptions for future unit costs.

Hence, this study presents two scenarios, “Constant Unit Cost” and “Escalating Unit Cost,” as plausible scenarios. “Constant Unit Cost” scenario assumes the unit costs remain constant in real terms throughout the projection. “Escalating Unit Cost” scenario assumes the unit costs escalate in real terms throughout the projection period. Included are the unit cost projections determinations based on regression of the historical pipeline and compression unit costs with natural gas production growth.

An assumption applied to unit costs for other type of assets (surface and lease equipment, offshore production platforms, gathering, processing and fractionation infrastructure projects) is that they escalate at the same average rate of the unit cost for pipelines and compressor stations. Estimates of capital expenditures for the projected infrastructure development apply the unit cost trends for each of these scenarios.

Exhibit 10: Scenario Assumptions and Trends

Macroeconomics	U.S. Gross Domestic Product (GDP) grows at 2.1 percent per year
	U.S. Industrial Production grows at 1.5 percent per year
	Global economic activity rebounds to pre-2015 growth rates
Oil and Gas Supply	U.S. Recoverable oil resource at 250 billion barrels and recoverable gas resource at 3,500 trillion cubic feet
	Recoverable resource appreciates by 0.8 percent per year
	Average well productivity improves by roughly 20 percent every 7-10 years
U.S. Oil Market Dynamics	WTI rises from current level to $75 per barrel (2016$) by 2025
	Other crude imports decline to 6.4 MMBpd by 2035
	Refinery input grows from 16.9 MMBpd in 2017 to 18.6 MMBpd by 2035
	Oil products transport up with refinery output

Exhibit 10: Scenario Assumptions and Trends (Continued)

U.S. Natural Gas Market Dynamics	Henry Hub prices average about $3.30 per MMBtu (2016$)
	Modest growth in households and commercial establishments using gas, mostly due to oil-to-gas conversions
	Petrochemical gas use up between 1 and 2 billion cubic feet per day (Bcfd) over current level by 2035
	Electric load growth averages 0.75 percent per year
	155 Gigawatts (GW) of coal plants retire by 2035
	16 GW of nuclear plants retire by 2035
	468 GWh of additional non-hydro renewables generation by 2035
	Modest penetration of gas vehicles amounts to 0.2 billion cubic feet per year of consumption post-2020
	LNG exports and exports to Mexico average 17.6 Bcfd after 2020
U.S. NGL Market Dynamics	NGL prices track oil and gas prices
	0.8 MMBpd of ethylene production (i.e., ethane crackers) added through 2035
	0.1 MMBpd of propane dehydrogenation (PDH) consumption added through 2035
	Butane & Pentane+ consumption grows by 0.65 MMBpd through 2035
	NGL exports average 2.0 MMBpd after 2020

3.2 Comparison of Supply, Demand, and Pipeline Capacity in the Scenarios

As mentioned above, both study scenarios use the same projections for U.S. and Canadian supply-demand and pipeline capacity. This section further examines those trends.

3.2.1 Projected Oil, Gas, and NGL Production

The projection in the study shows noticeable increases in production from shale and tight resources.

The study shows a robust growth in total crude oil production for the U.S. and Canada over the course of the projection (**Exhibit 11**). Increases in the Permian, Niobrara and Bakken oil production are more than offset by declines in conventional production. As a result, total U.S. production increases from its current level of roughly 14 million barrels per day to nearly 20 million barrels per day by 2035. This growing supply results in the need for new pipeline transport and oil handling capability.

U.S. natural gas production also sees significant growth – to 130 billion cubic feet per day (Bcfd) by 2035 (**Exhibit 12**) – spurred by growing markets. An increased resource base and accelerated technological advancement yields lower gas prices, and thus, greater market growth.

The concentration of U.S. natural gas production growth is in shale and tight formations. As is the case for oil, the productivity gains in shale resources continue to increase production from shale plays, while conventional onshore and other production that includes coalbed methane and offshore Gulf of Mexico gas supplies declines. Because shale plays are geographically widespread, production growth and the need for new infrastructure is geographically widespread. A natural gas capacity chart shown later in this section will illuminate this point. However, as discussed later, because production costs are relatively low in the Marcellus and Utica compared with production costs elsewhere, the study anticipates the concentration of both production and new infrastructure needs will be in the U.S. Northeast.

For NGLs, production growth is also very significant for each of the scenarios (**Exhibit 13**). This is because NGLs track natural gas production over time; that occurs because NGLs are a by-product of the gas production stream. NGL production grows by roughly 3.5 million barrels per day through 2035. NGL production growth is concentrated in unconventional (i.e., shale) resources.

It is worth noting that it will be important for NGL markets to grow to "absorb" the levels of production projected in the scenarios. Absent this market growth, stranded liquids could develop, potentially becoming a deterrent to natural gas market development. This point requires further elaboration since it is not necessarily an intuitive finding.

Ethane represents a significant portion of the NGL production increase, with 35 to 40 percent of the NGL stream containing that hydrocarbon. The gas stream can retain ethane and not separately extracted from the stream or produced. When retained in the stream and not separately produced, it is referred to as "ethane rejection." However, most U.S. natural gas pipelines set limits on the amount of ethane contained in the gas stream. As greater amounts get rejected into the gas stream, which is largely comprised of methane, the heat content for the entire stream rises and may potentially exceed pipeline limits. At that point, the stream is not suitable for gas pipeline transport, and would need to find another option for transportation to markets. In short, it is important for NGL markets to evolve so that ethane rejection does not become the proverbial "tail wagging the dog" for production.

Further, it is also uncommon for gas pipelines to transport propane or butane, as the heat content of those hydrocarbons is too high to for absorption into the stream. With the levels of NGL production exhibited in the scenarios, lack of markets for the liquids could strain gas transport. To avoid such a problem, development of ethane crackers, polypropylene facilities and NGL export terminals are necessary. Such market development would likely develop mostly along the Gulf Coast, making the development of incremental transport of liquids-laden streams via pipeline and/or rail a necessity.

Exhibit 11: Crude Oil Production in the Scenarios (Million Barrel per Day)

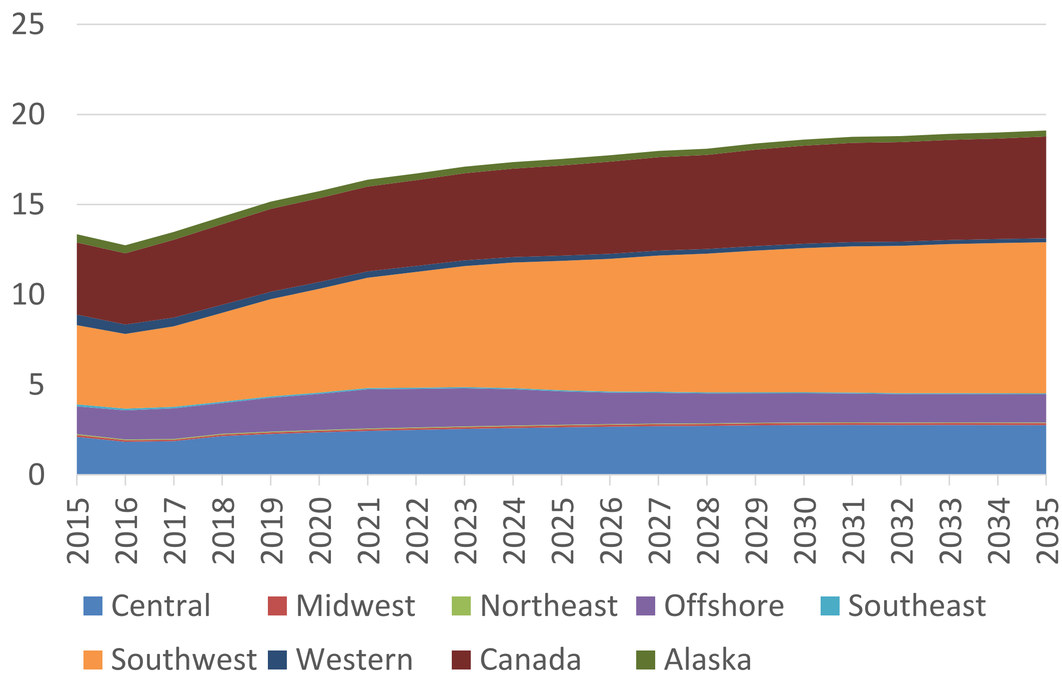


Exhibit 12: Natural Gas Production in the Scenarios (Billion Cubic Feet per Day)

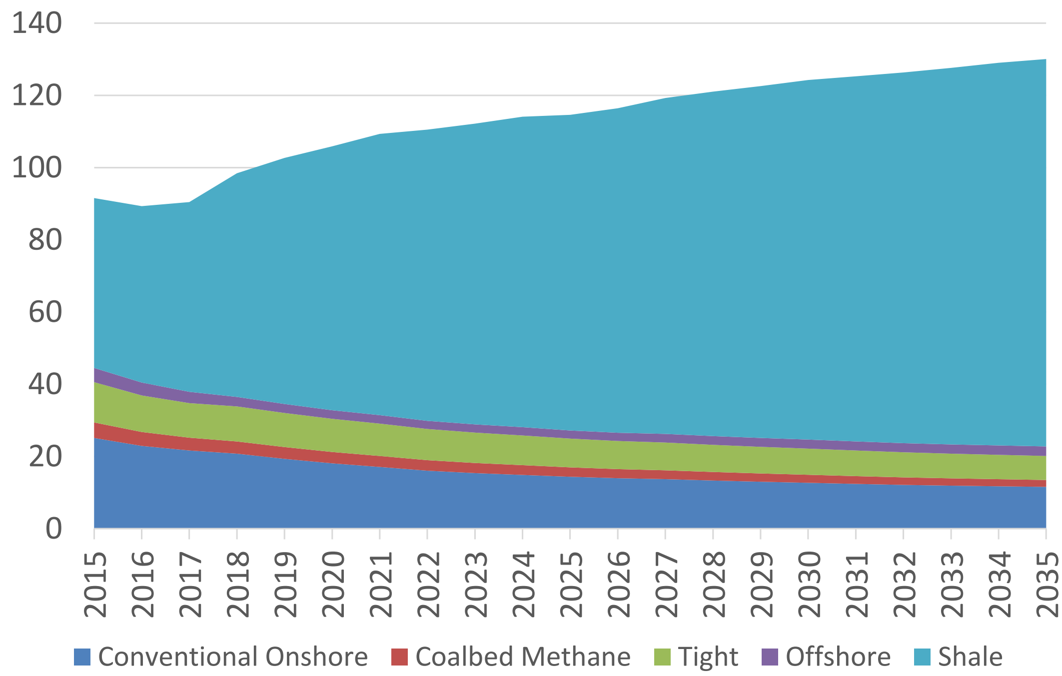
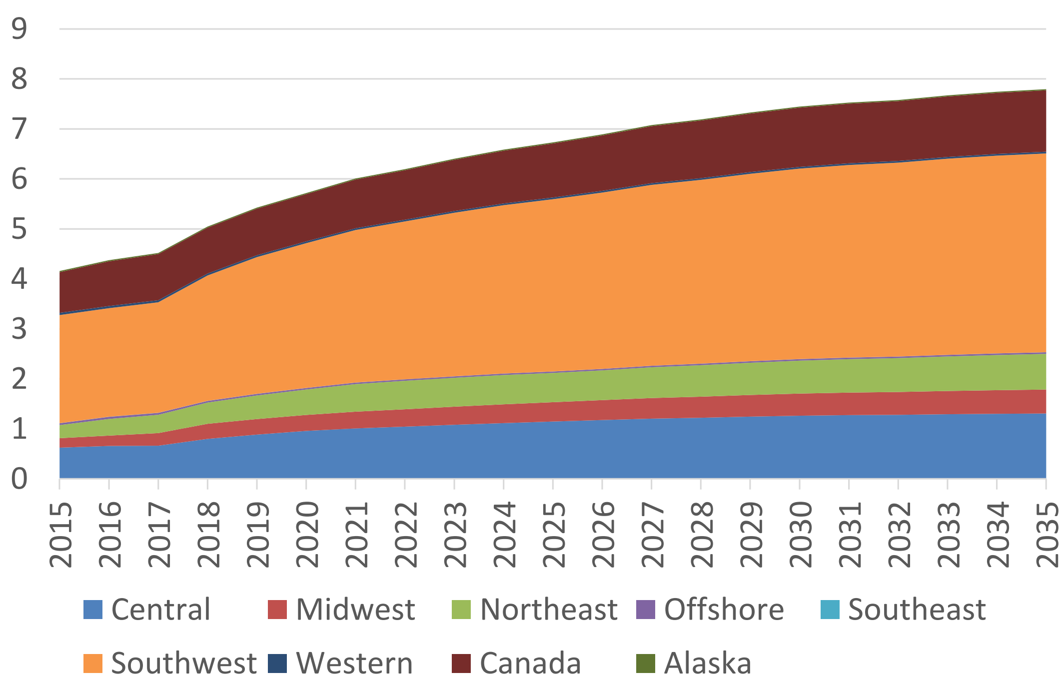


Exhibit 13: NGL Production in the Scenarios (Million Barrel per Day)



3.2.2 Projected Markets for Oil, Gas and NGLs

The study sees U.S. and Canada refinery output increasing as production from tight oil supplies and imports of heavy crude from Western Canada grow. **Exhibit 14** shows refinery crude oil input increase from their current level of 18.8 million barrels per day to 20.5 million barrels per day because of refinery upgrades and refurbishments.

Oil production increases from different regions in the U.S. and Canada. Much of the incremental supply to support an increasing utilization of U.S. refineries comes from Western Canada. While it is true that Canadian imports could increase by roughly 1 million barrels per day with projects like Keystone XL, the exhibit does not necessarily tell the full story. That is, the U.S. oil stream is becoming more highly comprised of light sweet crudes from regions like the Permian. In the future, the study sees greater U.S. refinery blending of the Canadian heavy oil with lighter crudes from the U.S.

Not only do the increased supplies of Canadian oil and the lighter sweeter crudes increase refinery input over time, but they also displace crude oil imports from other countries. The increase of domestic crude oil production along with the incremental imports of heavy crude oil from Western Canada potentially cuts crude oil imports from other countries in half over time. Increasing refinery input would increase oil product output and potentially higher U.S. exports of refined products.

U.S. and Canada natural gas demand, including LNG exports and pipeline export to Mexico, will increase to 130 billion cubic feet per day (**Exhibit 15**) from 91 billion cubic feet per day in 2017.

LNG exports, which grow to over 12 billion cubic feet per day in the study, represent one of the largest growth markets. LNG exports are supported by 15 to 30 trains of liquefaction capacity, almost entirely located along the U.S. Gulf Coast. A significant amount of liquefaction capacity is already under construction and scheduled to come online over the next few years.

The second-most noticeable area of growth for gas use comes from the power sector, where incremental gas use in the U.S. and Canada grows by 17 billion cubic feet per day. This is driven by retirement of coal-fired power plants, which will switch to low-cost natural gas or renewable generation, as well as electric-load growth and nuclear plant retirements. This study assumes significant electric load growth consistent with ISO projections. It also assumes that nuclear plants retire after they reach the age of 60 years.

The final two growth components for natural gas consumption are exports to Mexico and petrochemical gas use. Exports to Mexico rise by roughly 3 billion cubic feet per day, driven by replacement of Mexico's oil-fired generating facilities with gas-fired generating facilities. Petrochemical gas use in the U.S. grows by between 1 and 2 billion cubic feet per day. Most of the increase occurs at refineries, ammonia (fertilizer) plants and for methanol production.

The U.S. NGL market grows by 3.2 million barrels per day. The biggest growth component for NGLs is exports, which increase by 1.5 million barrels per day. Propane, most of which is exported to Asia to support polypropylene production, represents the single largest export component. Ethane, which is used in ethane crackers domestically to produce ethylene, sees the second largest growth. More modest growth occurs for butane and pentanes+, which are used mostly in refineries.

Exhibit 14: U.S. & Canada Refinery Input (Million Barrel per Day)

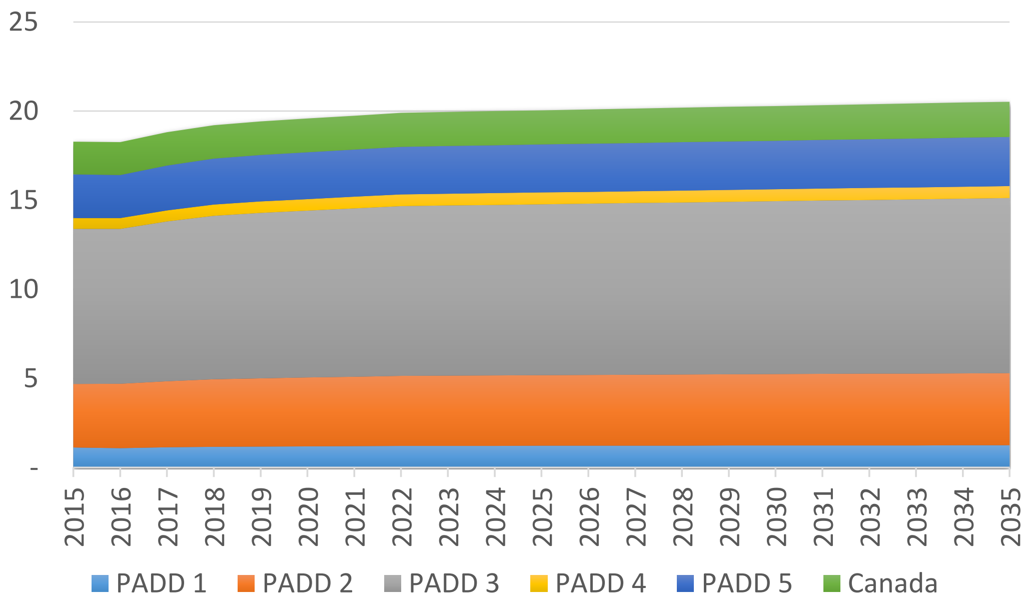
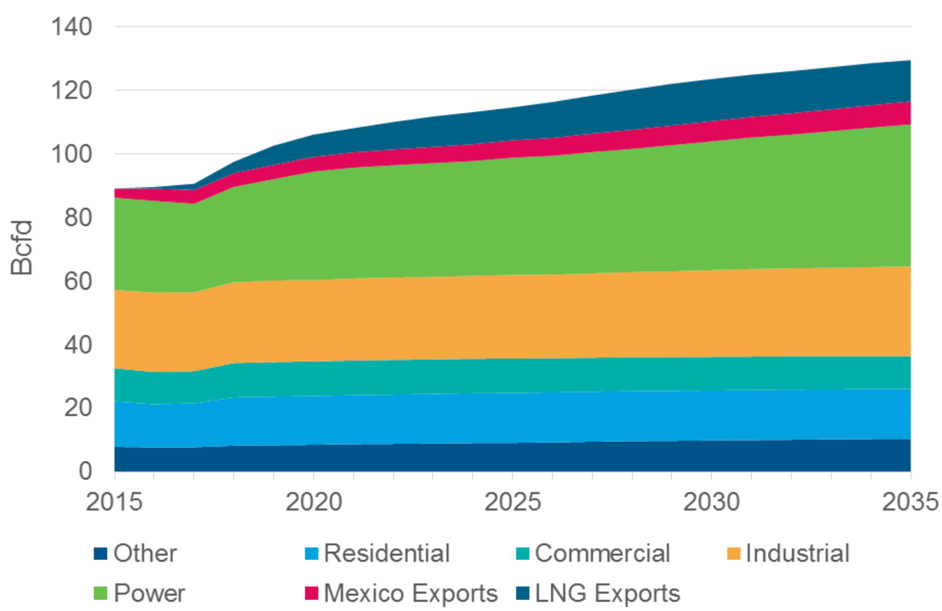


Exhibit 15: U.S. and Canada Natural Gas Market Growth (Billion Cubic Feet per Day)



3.2.3 Projected Transport of Oil, Gas, and NGLs

Considering the production and market dynamics discussed above, the study uses the modeling framework discussed in Section 2 to assess the amount of pipeline capacity needed to support transport of oil, gas, and NGL. This sub-section discusses results of that analysis. The study estimates the addition of 7.7 million barrels per day of new oil capacity. (**Exhibit 16**). Much of the new transport capability, or 0.9 million barrels per day, is already under construction and scheduled to be completed within the next 12 months (year 2018-2019).

Exhibit 16: Crude Oil Pipeline Capacity Added in the Scenarios (Million Barrel per Day)

Originating Region	2017	2018	2019-2020	2021-2025	2026-2030	2031-2035	Total 2018-2035	Average Annual 2018-2035
U.S. and Canada	**1.8**	**0.9**	**1.6**	**3.8**	**1.0**	**0.5**	**7.7**	**0.4**
U.S.	**1.7**	**0.9**	**1.6**	**2.3**	**0.6**	**0.5**	**5.8**	**0.3**
Canada	**0.1**	**-**	**-**	**1.4**	**0.4**	**-**	**1.8**	**0.1**
Central	0.8	-	-	1.0	0.1	-	1.1	0.1
Midwest	0.6	-	-	-	-	-	-	-
Northeast	-	-	-	-	-	-	-	-
Offshore	-	-	-	-	-	-	-	-
Southeast	-	-	-	-	-	-	-	-
Southwest	0.3	0.9	1.6	1.4	0.5	0.5	4.8	0.3
Western	-	-	-	-	-	-	-	-
Alaska	-	-	-	-	-	-	-	-

Geographically, that capacity is concentrated in the Central, Midwest and Southwest. Incremental transport in the Central and Midwest is already being added to support imports of heavy crude oil from Alberta's oil sands. These are legacy projects that were already underway before the collapse in oil prices and near-term slowdown in oil sands development. Another portion of the capacity is aimed at transporting incremental supplies from the Bakken toward the East Coast and Gulf Coast. Yet another portion of the capacity transports growing supplies of crude oil from West Texas to refineries concentrated mostly along the Texas Gulf Coast.

In each of the cases after 2020, 1.8 million barrels per day of incremental transport is needed to support imports of heavy crude from Alberta's oil sands. Most of the incremental capacity, or 4.8 million barrels per day is added in the Southwest to support additional transport of crude oil from the Permian Basin toward the Midcontinent and Gulf Coast refinery complex. The Permian Basin is the most prolific and cost-effective U.S. oil-producing area, so it stands to reason that any resource base improvements and technological advances would have a more pronounced impact on production from that area. The remainder of the incremental transport originates from the Bakken into the Midwest.

Most new U.S. oil pipeline transport project is projected for completion in the next is five to 10 years (2023 to 2028). As oil production growth slows over the projection period, the need of incremental capacity also slows as already-built capacity is relied on to transport incremental supplies.

The study projects the need for 57 billion cubic feet per day of new gas pipeline capacity to support the levels of production and market growth that are projected through 2035 (**Exhibit 17**). That means 3.1 billion cubic feet per day per year of incremental transport is added to an already extensive gas transportation network that currently provides roughly 150 billion cubic feet per day of transport capability. Thus, the size of the U.S. gas transportation network will increase at a rate of roughly 2.5 percent per year in the future.

Unlike oil transport, which is more geographically limited, the buildout of the gas transportation network is expected in many different areas. Much of the new gas pipeline capacity will originate from the massive Marcellus and Utica production basins. The study estimates about 25 billion cubic feet per day of new capacity to move Marcellus and Utica supplies to consumers and export facilities.

Because there are many different pipeline projects aimed at providing the incremental transport for Marcellus/Utica gas, many different companies will benefit from development of the area's gas supplies. Further, impacts of the development of the area's gas will have far-reaching benefits for the nation's gas consumers and the overall economy, as discussed in Section 5.

Exhibit 17: Natural Gas Pipeline Capacity Added in the Scenarios (Billion Cubic Feet per Day)

Originating Region	2017	2018	2019-2020	2021-2025	2026-2030	2031-2035	Total 2018-2035	Average Annual 2018-2035
U.S. and Canada	**15.0**	**19.6**	**18.1**	**4.3**	**9.2**	**5.5**	**56.7**	**3.1**
U.S.	**13.8**	**17.6**	**15.3**	**3.8**	**8.7**	**5.0**	**50.4**	**2.8**
Canada	1.2	2.0	2.8	0.5	0.5	0.5	6.3	0.3
Central	0.1	0.4	0.9	1.6	1.3	0.5	4.6	0.3
Midwest	4.3	2.6	0.4	1.0	3.4	1.0	8.4	0.5
Northeast	1.7	6.6	3.6	1.0	3.0	2.5	16.7	0.9
Offshore	-	-	-	-	-	-	-	-
Southeast	4.2	2.4	0.8	0.2	-	-	3.3	0.2
Southwest	3.6	5.7	9.0	-	1.0	1.0	16.6	0.9
Western	-	-	0.7	-	-	-	0.7	0.0
Alaska	-	-	-	-	-	-	-	-

Development of Marcellus/Utica supplies as well as development of supplies from other basins (e.g., the Haynesville in Northwest Louisiana and East Texas) will impact development elsewhere because of the market growth that these supplies support. Thus, the scenarios project a significant amount – 20 billion cubic feet per day – of new capacity is needed in the Southwest and Southeast, primarily to facilitate LNG and Mexican exports as well as growth of gas-fired power generation.

The study finds little need for new gas pipeline capacity in the Central and Western U.S. These areas are already “over-piped” and have modest expectations for market growth. Indeed, gas consumption in these areas may struggle to keep pace with growth elsewhere. Gas consumption may even decline in the westernmost parts of the continent, especially in California where there is an increased focus on renewable energy policies.

Unlike oil, where development of new capacity noticeably slows over the projection period, the study projects more uniform gas pipeline capacity development throughout the projection period. While the cases project a slowdown from the very robust expansion that is likely to take place over the next few years, the scenarios also project 19 billion cubic feet per day of new capability in the U.S. and Canada after 2020. This result depends on the size of the resource base and continued technological advancements.

For transport of NGLs, the study projects the development of 3.6 million barrels per day of new pipeline capacity to support the production and market growth projected through 2035 (**Exhibit 18**). Almost all this new capacity will be placed in service over the next decade.

Exhibit 18: NGL Pipeline Capacity Added in the Scenarios (Million Barrel per Day)

Originating Region	2017	2018	2019-2020	2021-2025	2026-2030	2031-2035	Total 2018-2035	Average Annual 2018-2035
U.S. and Canada	**0.5**	**0.9**	**1.8**	**0.4**	**0.4**	**-**	**3.6**	**0.2**
U.S.	**0.3**	**0.8**	**1.5**	**0.4**	**0.3**	**-**	**3.1**	**0.2**
Canada	**0.1**	**0.1**	**0.3**	**-**	**0.1**	**-**	**0.5**	**0.0**
Central	-	0.0	0.2	-	-	-	0.3	0.0
Midwest	-	0.3	0.2	0.3	-	-	0.8	0.0
Northeast	0.1	0.3	-	-	-	-	0.3	0.0
Offshore	-	-	-	-	-	-	-	-
Southeast	-	-	-	-	-	-	-	-
Southwest	0.3	0.2	1.0	0.1	0.3	-	1.6	0.1
Western	-	-	-	-	-	-	-	-
Alaska	-	-	-	-	-	-	-	-

The areas for development of new capacity include the: 1) Northeast – home to the Marcellus and Utica, where gas production is likely to continue to grow very rapidly; 2) the Midwest, where the Aux Sable liquids extraction facility resides; and 3) the Southwest, where there are potentially a large number of "wet" gas plays that contain significant amounts of liquids resource. The last of these areas, the Southwest, is also home to Mont Belvieu, TX, a widely recognized location for NGL transactions, that is near several sites where additional petrochemical facilities (i.e., ethane crackers and polypropylene plants) and NGL export terminals could be built or expanded.

4 Oil and Gas Infrastructure Requirements

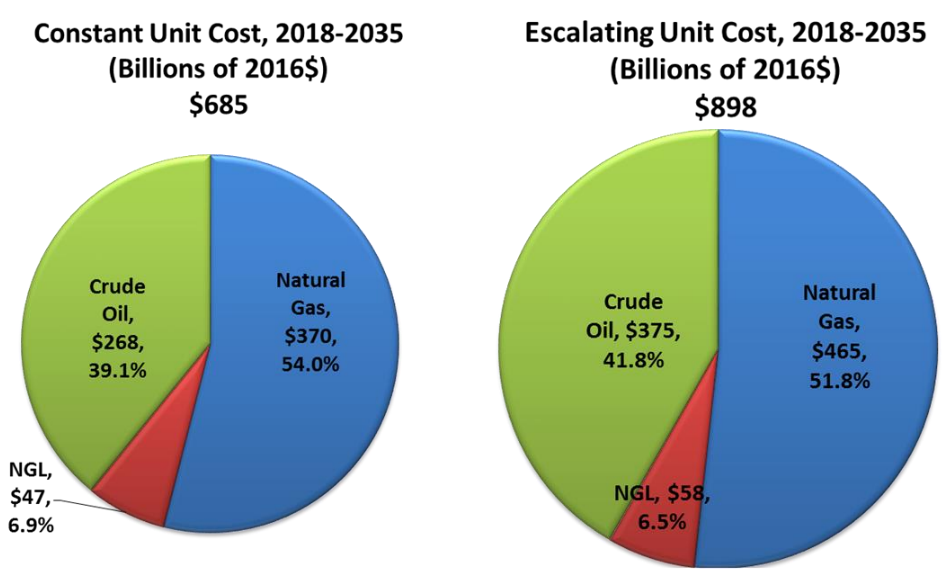
The supply, demand, and transport dynamics discussed in the previous section lay the foundation for determining the need for oil, gas and NGL infrastructure. New infrastructure will be required to process and transport hydrocarbons from regions where production is projected to grow to locations where the hydrocarbons are used. Thus, the types and amounts of oil and gas infrastructure and the associated capital investment is dependent on how the produced volumes of crude oil, natural gas and NGLs are processed, refined and transported across the U.S. and Canada.

This section examines the oil and gas infrastructure needed for each of the scenarios. It begins with a high-level overview of infrastructure requirements, and then investigates the specific requirements for each infrastructure category. It then examines regional trends for infrastructure development and expenditures. Results from this section are applied in the following section to analyze the potential economic impacts of oil, gas and NGL infrastructure development, most notably employment and GDP impacts.

4.1 Overview of Oil and Gas Infrastructure Development

Applying the modeling tools and methodology discussed in Section 2, total oil and gas infrastructure investment is projected to range between $685 billion and $898 billion from 2018 through 2035 for the Constant Unit Cost and Escalating Unit Cost, respectively (**Exhibit 19**), averaging between $55 billion and $70 billion per year. These estimates align well with the aforementioned oil and gas infrastructure investment of $316 billion (roughly $63.2 billion a year) that has occurred during the past five years, suggesting that the robust environment for oil and gas infrastructure development has not yet run its course and is likely to continue for many years.

Exhibit 19: Projected Capital Investment in Oil and Gas Infrastructure from 2018-2035 (Billion 2016$)

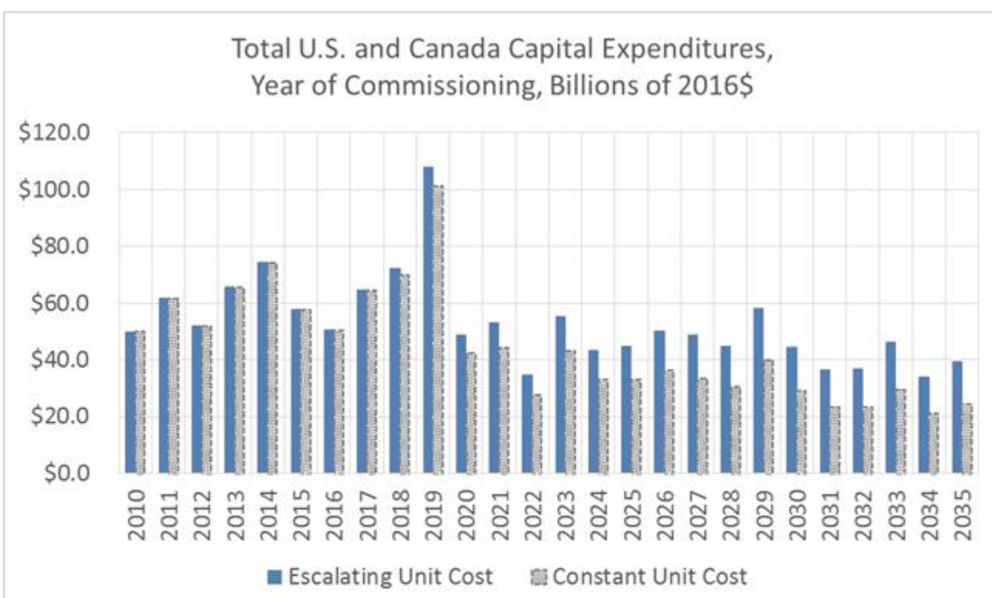


Investment is strongest for natural gas gathering, processing and transport, with capital outlays totaling between $370 billion and $465 billion over the projection period, accounting for between 54 and 52 percent of the total investment. Natural gas infrastructure development has significant upside and risk because of uncertainties around gas market development. Oil capital expenditures range from $268 billion to $375 billion. NGL investment is a more modest $47 billion to $58 billion (i.e., 6 percent of the total), as expenditures are more narrowly focused on fractionation facilities and a few large pipeline projects.

Much of the infrastructure projected faces regulatory hurdles, but because this study is aimed at quantifying potential infrastructure development and its associated CAPEX, it assumes that regulatory hurdles will be overcome and infrastructure will be built in response to market needs. However, it is worth noting that project delays from the regulatory approval processes or legal challenges pose significant downside risk for projected investment and the associated economic benefits discussed later in Section 5.

For the most part and as mentioned above, infrastructure development and its associated CAPEX is relatively steady throughout the projection period, averaging between $38 billion and $50 billion per year (**Exhibit 20**). While robust infrastructure buildout is likely to continue over the next few years, development remains significant even in the longer term, with investment in new infrastructure (not including enhancements, upgrades, replacements and refurbishments of existing infrastructure) ranging between $34 and $58 billion after 2020. Investment is, however, much higher in the Escalated Unit Cost Case where the aforementioned upside potential for gas infrastructure development is realized.

Exhibit 20: Oil and Gas Infrastructure CAPEX by Year (Billion 2016$)



4.2 Oil and Gas Infrastructure Development by Category

This portion of the report discusses investment by category. Expenditures across categories are first discussed in broad terms directly below, and then each category is separately examined.

Among the categories, investment is greatest for surface and lease equipment, with capital expenditures totaling between $222 billion and $319 billion from 2018 to 2035, accounting for 32 and 35 percent of the total oil and gas infrastructure investment (**Exhibit 21**). The average annual CAPEX is steady from year to year, ranging from $12.3 billion to $17.7 billion per year (**Exhibit 22**).

Pipeline development ranks second, with total CAPEX of $236 billion to $293 billion over the projection, accounting for 34 and 33 percent of the total oil and gas infrastructure investment. These amounts equate to an average annual CAPEX of between $13.1billion and $16.3 billion.

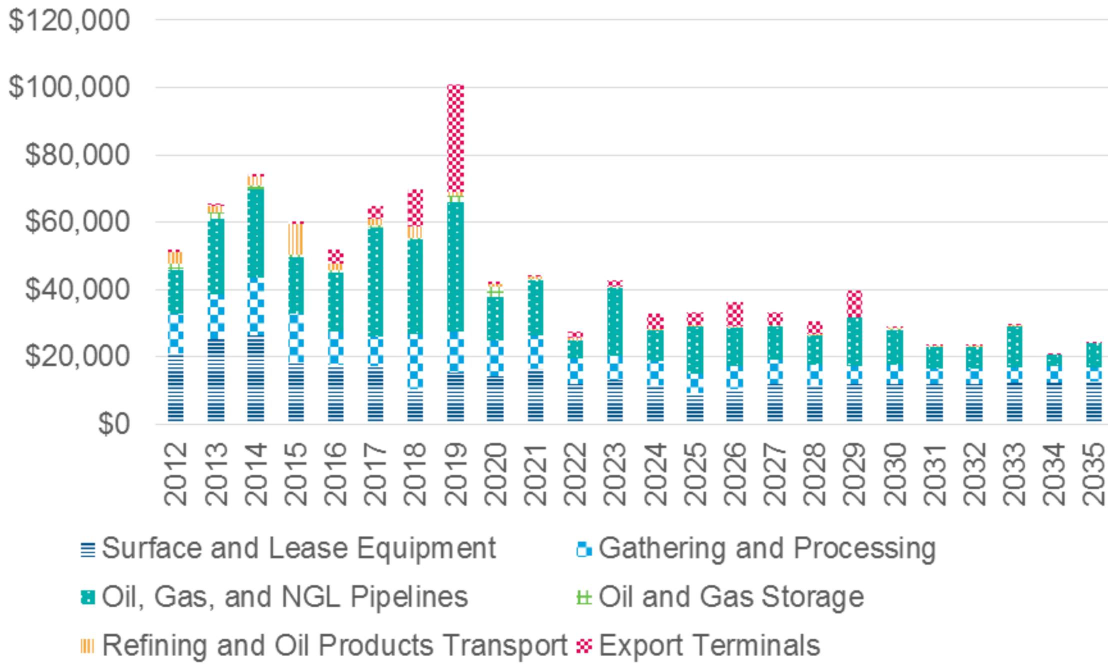
Gathering and processing investment runs a close third, with a total CAPEX of $130 billion to $174 billion over the projection, accounting for 19 percent of the total oil and gas infrastructure investment. The average annual expenditure is $7.2 billion to $9.7 billion. The three remaining categories—export terminals, refining and oil products transport and oil and gas storage – collectively add a total CAPEX of $96 billion to $112 billion over the projection, or $5.4 billion to $6.2 billion annually.

Exhibit 21: Oil and Gas Infrastructure CAPEX from 2018-2035 by Category (Million 2016$)

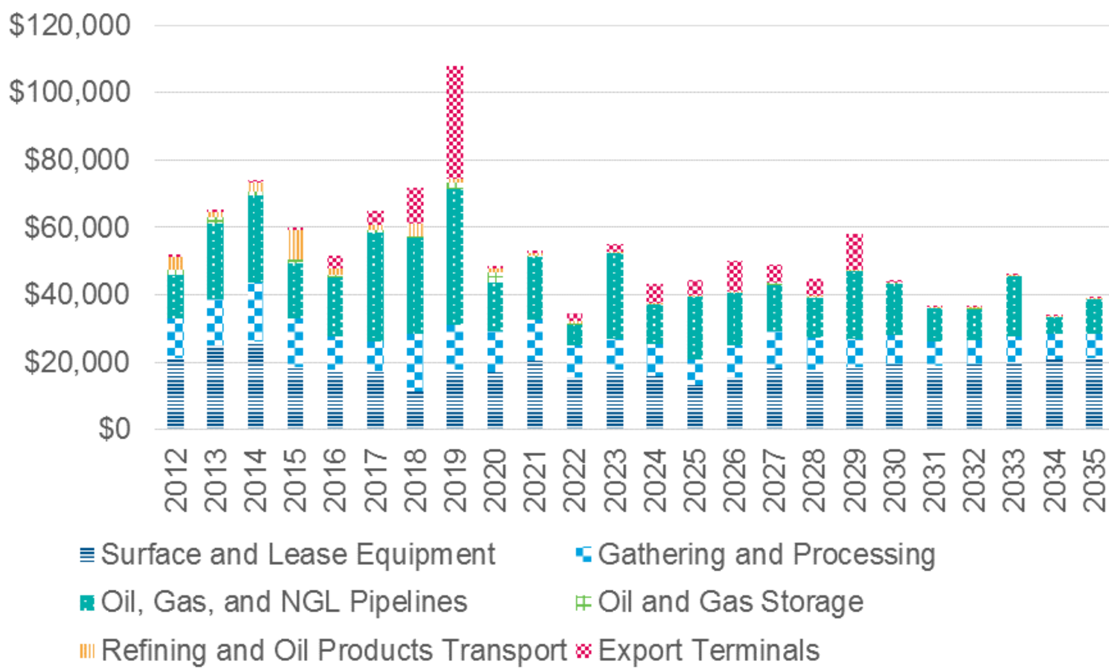
	2013-2017		Constant Cost, 2018-2035		Escalating Cost, 2018-2035	
	CAPEX	% of Total	CAPEX	% of Total	CAPEX	% of Total
Surface and Lease Equipment	$104,656	33.1%	$221,863	32.4%	$318,659	35.5%
Gathering and Processing	$64,024	20.2%	$130,334	19.0%	$173,985	19.4%
Oil, Gas, and NGL Pipelines	$115,114	36.4%	$235,919	34.5%	$292,951	32.6%
Oil and Gas Storage	$5,334	1.7%	$6,695	1.0%	$8,019	0.9%
Refining and Oil Products Transport	$17,031	5.4%	$9,572	1.4%	$11,397	1.3%
Export Terminals	$10,151	3.2%	$80,171	11.7%	$92,668	10.3%
Total Expenditures	$316,310	100.0%	$684,555	100.0%	$897,678	100.0%

Exhibit 22: Annual Oil and Gas Infrastructure CAPEX by Category (Million 2016$)

Constant Unit Cost Case



Escalating Unit Cost Case



4.2.1 Capital Expenditures for Surface and Lease Equipment

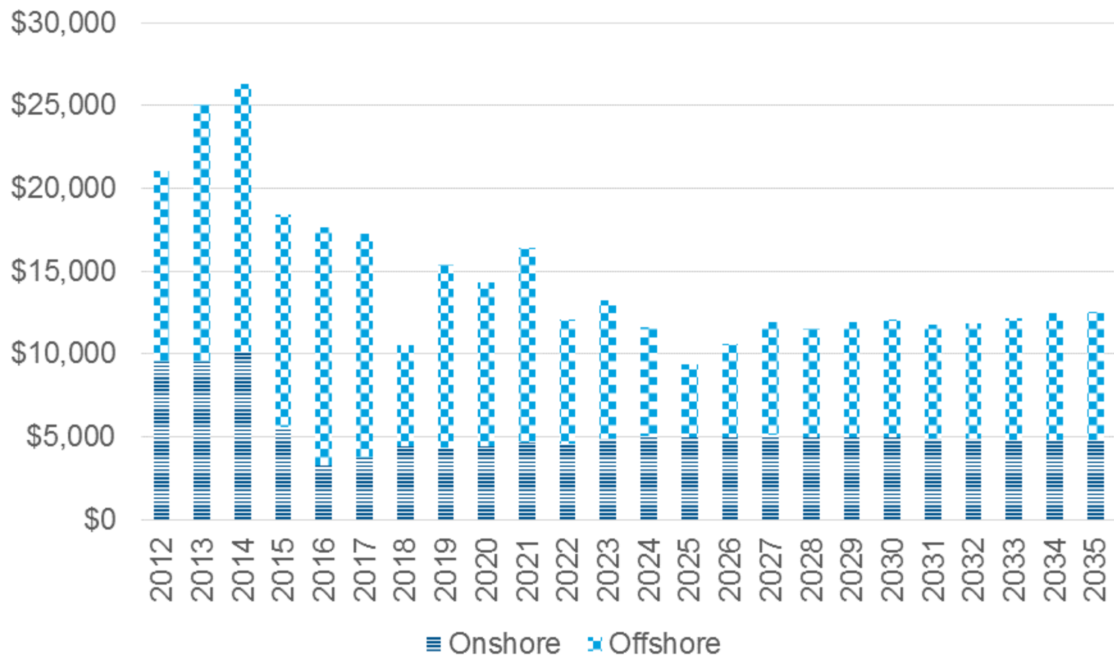
As discussed above, surface and lease equipment capital expenditures total $222 billion and $319 billion over the projection. These values equate to annual expenditures of $12.3 billion to $17.7 billion for the Constant Unit Cost Case and Escalating Unit Cost Case, respectively (**Exhibit 23**). The values align well with average annual expenditures over the past five years.

Over half of the investment in surface and lease equipment is devoted to offshore oil platforms in the Gulf of Mexico, with a projected annual CAPEX averaging between $7.5 billion and $11.0 billion. Rebounding oil prices to $75 per barrel in real terms in each of the scenarios bolsters offshore development, with nearly 350,000 barrels of oil equivalent per day added each year in both scenarios. These statistics, as well as others, are listed in the exhibit and are also shown in tables showing regional detail in Appendix B. The production levels require seven new platforms every year, each of which are relatively large deep-water platforms costing about $1 billion.

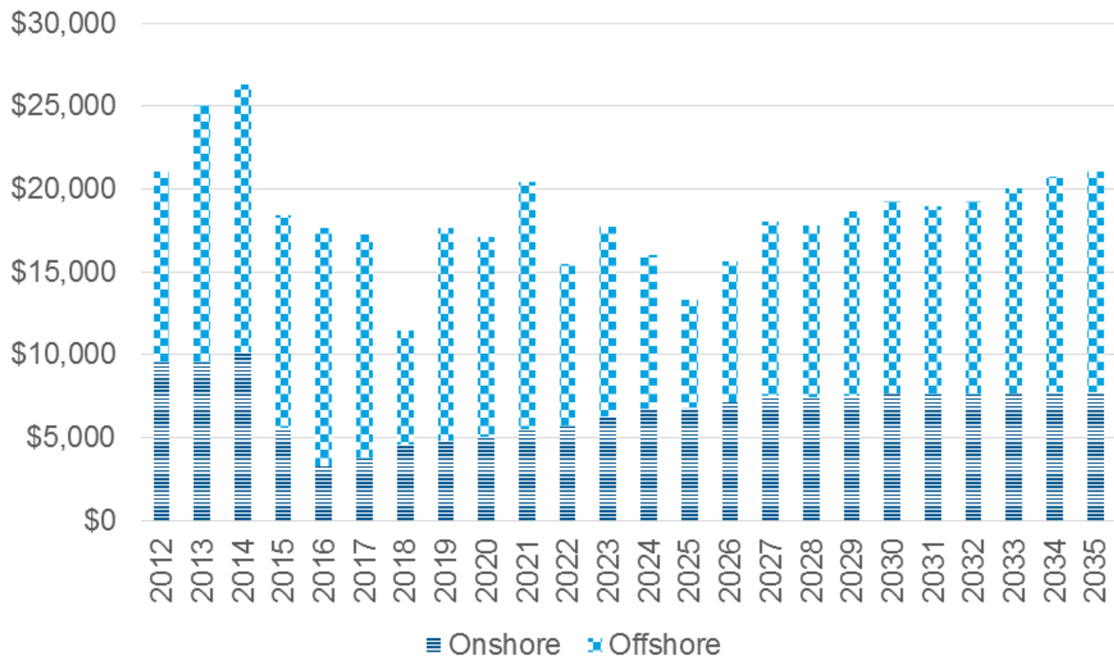
Projected annual CAPEX for onshore surface and lease equipment averages $4.8 billion and $6.7 billion for the Constant Unit Cost Case and Escalating Unit Cost Case, respectively. While these values are significant, they are somewhat below levels from ten years ago as the number of annual well completions in the U.S. has declined significantly since that time. With the move away from conventional resource to shale and tight resource development, individual wells have become more productive. Thus, fewer wells are required to increase production compared with a decade ago. Because there are fewer wells needed, the amount of surface and lease equipment projected year by year is also much less than it once was, driving down surface and lease equipment expenditures relative to historical expenditures. Today’s equipment is built to handle larger volumes of production, offsetting some of the cost reduction.

Exhibit 23: Surface and Lease Equipment CAPEX (Million 2016$)

Constant Unit Cost Case



Escalating Unit Cost Case



4.2.2 Capital Expenditures for Gathering and Processing

As discussed above, gathering and processing capital expenditures rank third, with investment totaling $130 billion to $174 billion over the projection. These values equate to annual expenditures of $7.2 billion to $9.7 billion for the Constant Unit Cost Case and Escalating Unit Cost Case, respectively (**Exhibit 24**), somewhat below the average annual expenditures during the past five years of $12.8 billion per year due to large buildout in the 2013-2015 period.

Roughly one-third of the total investment for this category is devoted to gathering lines, with a projected annual CAPEX averaging between $2.2 billion and $3.0 billion for the Constant Unit Cost and Escalating Unit Cost Case, respectively. The study anticipates the construction of 7,720 miles of gathering lines in the U.S. and Canada each year, or a total of nearly 140,000 miles throughout the projection. Roughly 64 percent of the new lines are for gas gathering, with the remainder added for oil gathering. Oil lines account for a smaller portion of gathering because there are significant amounts of crude oil stored in tanks near the wellhead and transported by truck instead of pipe. Gathering line size generally averages 8-inches in diameter, but there is a great deal of regional variance in the diameter, as shown in tables in Appendix B.

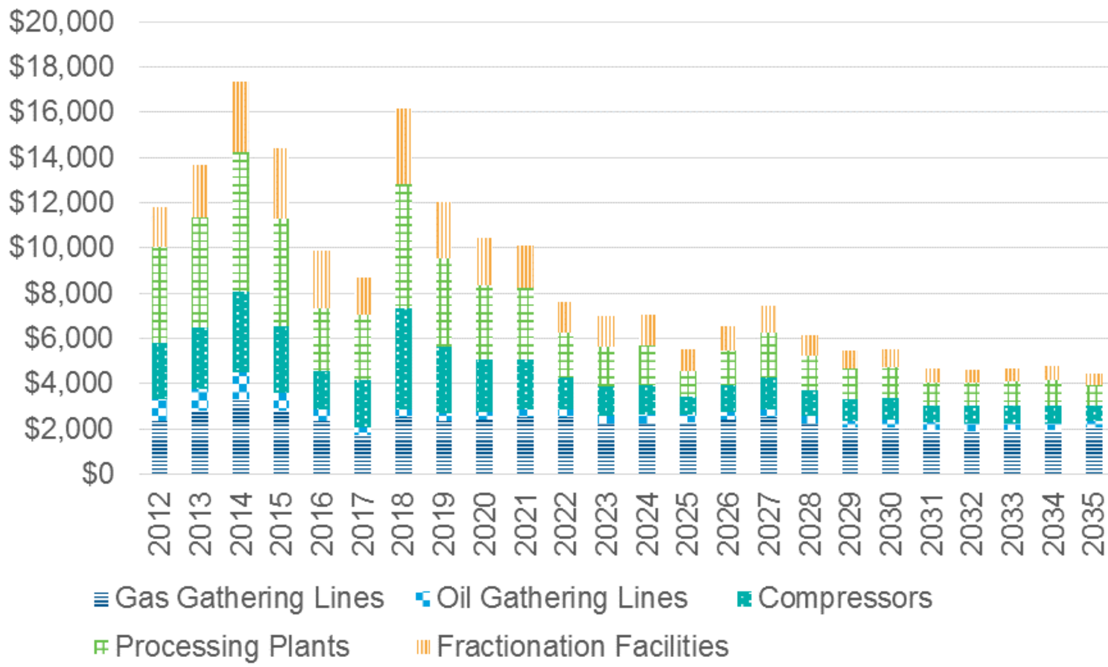
To support the gas gathering process, the study estimates 474,000 horsepower of compression additions each year, yielding an annual investment of $1.5 billion to $2 billion. Most gathering lines will feature modularized skid-mounted units that can be easily added or removed over time.

Investment in gas processing plants averages $2.0 billion to $2.6 billion per year for the Constant Unit Cost and Escalating Unit Cost Case, respectively. This sub-category includes separators, treaters, dehydrators, meters, control equipment, valves and compressors located within the confines of the processing plant. Expenditures support average annual of 2.1 billion cubic feet per day of new processing capacity, which equates to 38.1 billion cubic feet per day of processing capacity throughout the projection. Across the U.S. and Canada, this amount of capacity means the addition of about eleven processing plants, each processing about 200 million cubic feet of natural gas per day, each year.

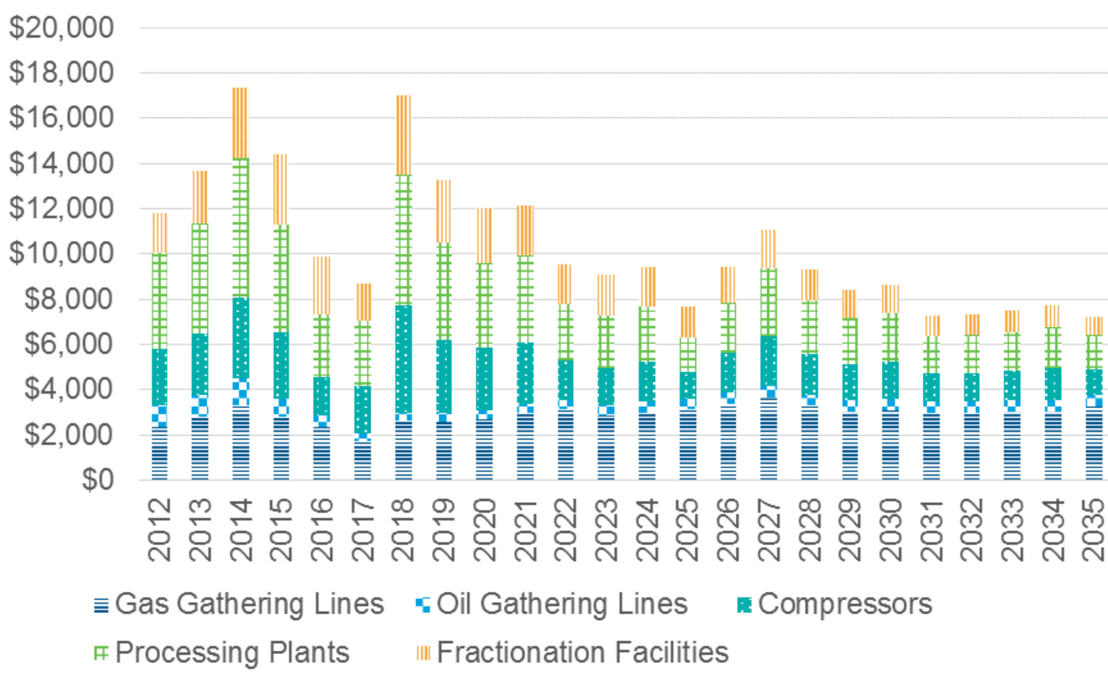
This analysis also estimates 199,000 barrels per day of new NGL fractionation capacity each year, at an annual CAPEX of $1.3 billion to $1.6 billion for the Constant Unit Cost and Escalating Unit Cost Case, respectively. The annual capacity additions represent about two or three fractionation plants each year, assuming average per-unit processing capacity of 75,000 barrels per day of NGLs.

Exhibit 24: Gathering and Processing CAPEX (Million 2016$)

Constant Unit Cost Case



Escalating Unit Cost Case



4.2.3 Capital Expenditures for Oil, Gas, and NGL Pipelines

As discussed above, capital expenditures for oil, gas and NGL pipelines rank second behind surface and lease equipment, with investment totaling $236 billion to $292 billion over the projection. These values equate to annual expenditures of $13.1 billion to $16.3 billion for the Constant Unit Cost Case and Escalating Case, respectively (**Exhibit 25**). While these values are somewhat below average annual expenditures that have recently averaged just over $23 billion, they are still very significant and suggest a continuation of the already robust oil and gas pipeline buildout.

Roughly 65 percent of the total investment in this category is for natural gas pipelines, with an average annual CAPEX of $8.5 billion to $10.6 billion. These values equate to a total of $154 billion to $190 billion throughout the projection, for the Constant Unit Cost Case and Escalating Case, respectively.

The study estimates construction of roughly 1,400 miles of natural gas pipeline each year, with a total of 26,000 miles put in place throughout the projection. There is significant upside and risk for natural gas pipeline development, depending on market evolution and project approvals. The study estimates 391,000 horsepower of compression added each year, or a total of 7 million horsepower of compression over the course of the projection.

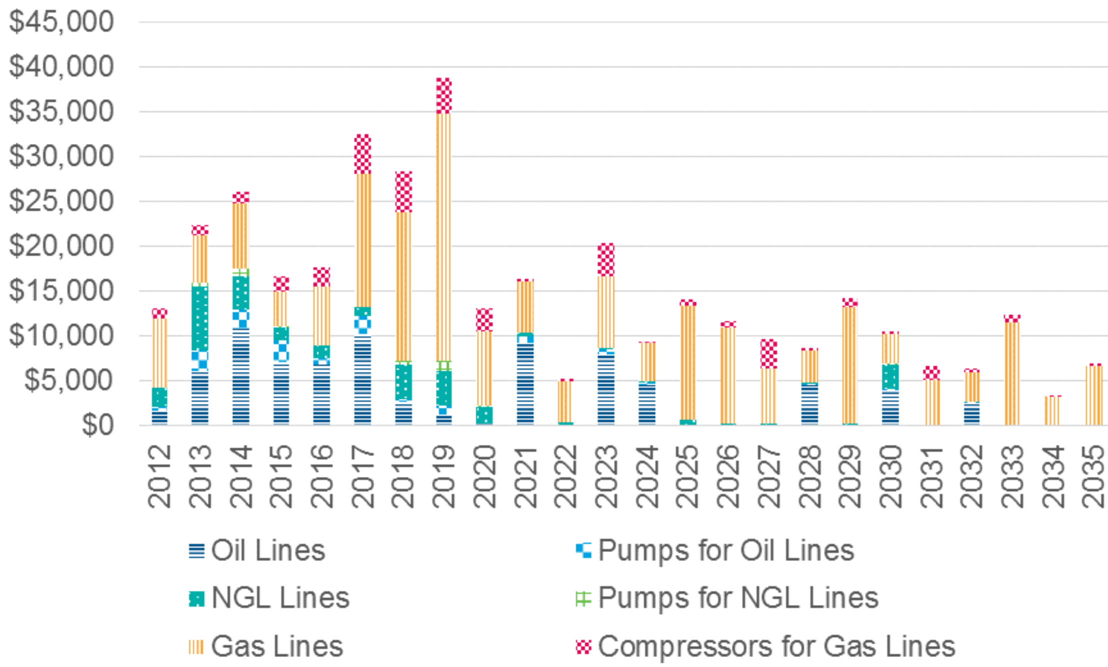
The study estimates oil and NGL pipeline investments at an average $2.9 billion to $3.6 billion per year, or between $53 billion and $65 billion over the entire projection. There are far fewer miles of oil and NGL pipeline required in the scenarios than gas pipelines. The report estimates the addition of 850 miles of combined NGL and oil pipelines a year or a total of 15,000 miles over the entire projection. Pumping requirements for oil and NGL pipelines will total 73,000 horsepower each year, or 1.3 million horsepower over the entire projection.

Much of the new oil pipeline that is required is already under construction or could be added with a few large projects. The same can also be said for NGL transport, where a few large projects could yield much of the needed capacity. Thus, oil and NGL pipeline investments are uneven over time, particularly when compared with natural gas pipeline investments, which is much steadier throughout the projection.

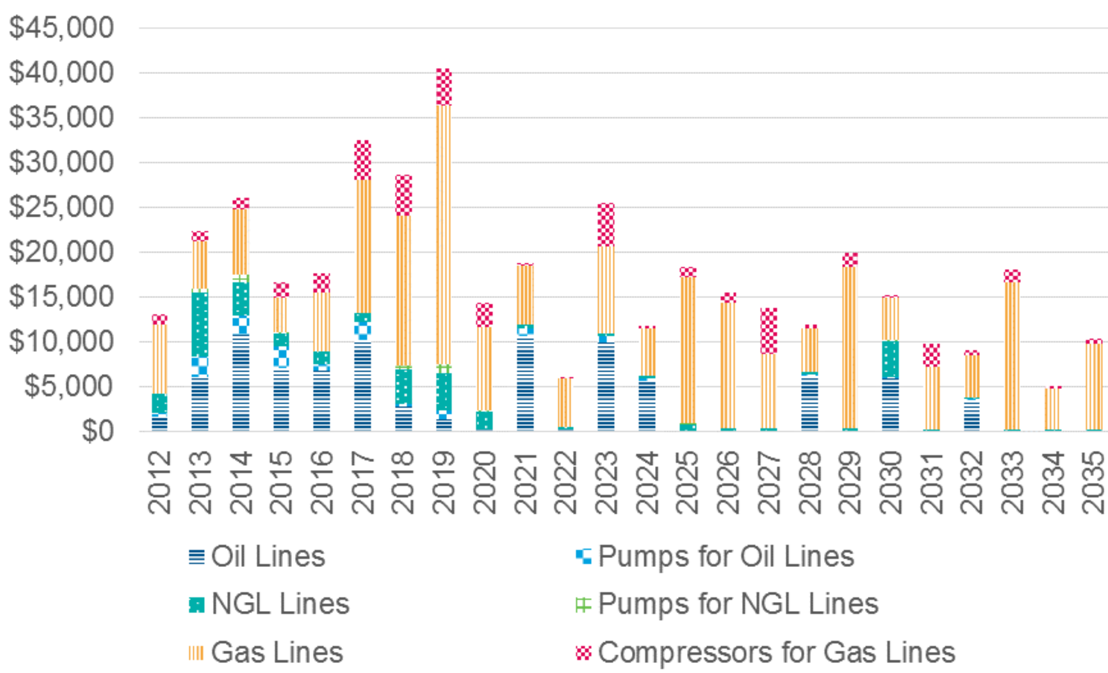
The study finds that most pipeline capacity added in each of the scenarios is large pipe, averaging just over 26-inches in diameter. Some of the projects, particularly the oil projects transporting heavy crude oil from Western Canada into the U.S. and toward the Gulf Coast require very large pipe, each of which is upwards of 32-inches in diameter.

Exhibit 25: Oil, Gas, and Natural Gas Liquids (NGLs) Pipeline CAPEX (Million 2016$)

Constant Unit Cost Case



Escalating Unit Cost Case



4.2.4 Capital Expenditures for Oil and Gas Storage

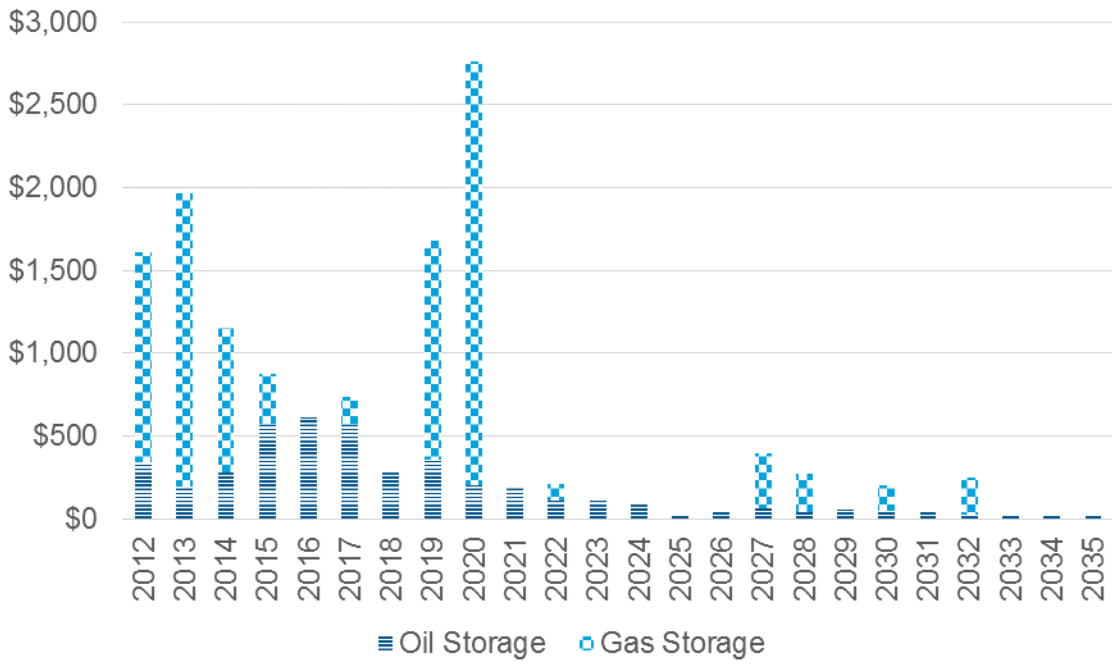
The report anticipates modest capital expenditures for oil and gas storage because a vast amount of oil and gas storage capacity already is in place across the U.S. and Canada. The report estimates total capital expenditures of $6.7 billion to $8.0 billion over the projection period, equating to an average annual CAPEX of $372 million to $446 million (**Exhibit 26**).

Even though there is already a large amount of storage in place, the model adds incremental storage in response to market and supply growth. For crude oil, storage is added to provide a temporary "holding location" for supplies until they are transported to centralized tank farms and/or refineries. The model adds 7.7 million barrels of storage per year in response to the production growth that occurs. Total storage additions approach 140 million barrels by 2035, in line with the model's crude oil production growth of nearly 5.6 million barrels per day.

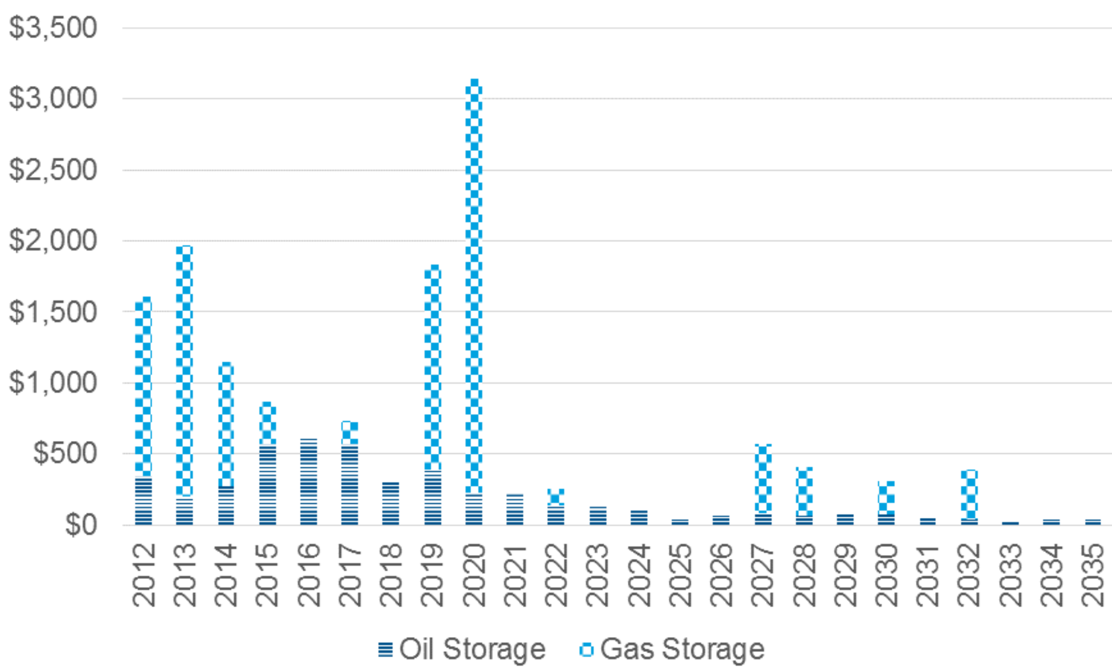
About 19 billion cubic feet per year of working natural gas capability is added. This added storage is mostly high-deliverability salt cavern storage located near growth markets, particularly large petrochemical facilities, power plants and LNG export facilities. The gas storage additions help manage loads and balance consumption with supplies.

Exhibit 26: Oil and Gas Storage CAPEX (Million 2016$)

Constant Unit Cost Case



Escalating Unit Cost Case



4.2.5 Capital Expenditures for Refining and Oil Products Transport

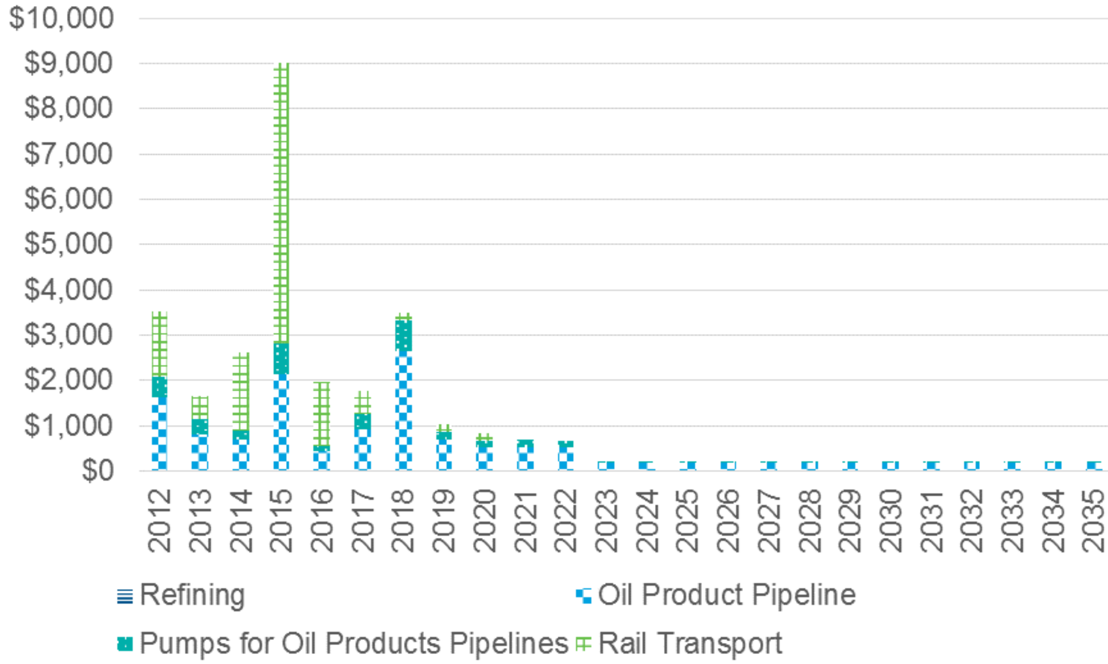
The scenarios project capital expenditures for refining and oil products transport of $9.6 to $11.4 billion from 2018 to 2035. These values equate to $532 to $633 million per year (**Exhibit 27**). While these values are significant, they are lower than recent annual expenditures that have averaged close to $3.4 billion. In the recent past, companies have invested almost $2 billion for rail transport of crude, an investment not necessary in the future, as explained below.

The report estimates construction of 166 miles of new oil products pipelines, at an average size of 14-inches in diameter, each forecast year to support the takeaway of the increased product production from the refineries. Annual CAPEX for the oil products pipelines will range from $400 million to $470 million, additions of 29,000 horsepower per year to support the transport of oil along the pipelines.

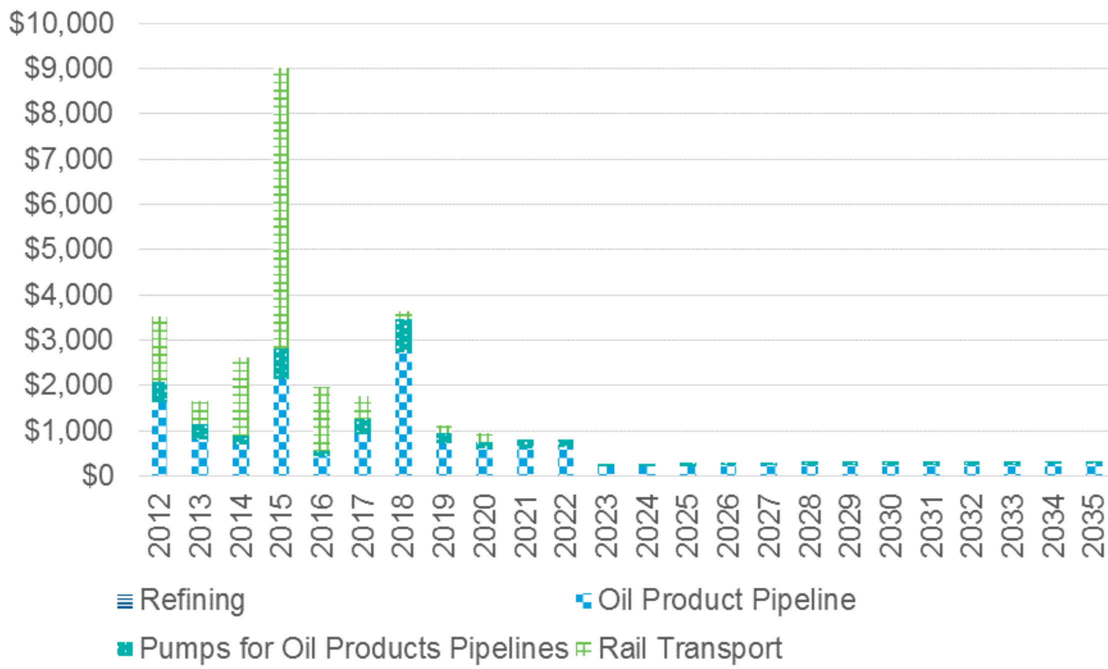
Perhaps the most surprising result for this category of oil infrastructure investment is the lack of investment in new rail transport, as alluded to above. This result occurs for two reasons. First, a significant part of recent historical expenditures for rail transport of crude oil has been focused on replacing aging rail cars to comply with recent regulations. To date, a substantial portion of the fleet has been replaced, although about 900 new crude oil cars per year will be needed between now and 2020. The second reason, which is the more significant driver of the result, is that the study assumes new pipeline capacity will transport almost all incremental crude oil and refined products. In the future, if shippers determine that rail transport is more valuable because of it's of rail transport, "optionality" that pipelines do not necessarily offer, rail CAPEX could increase. However, if additional rail transport were to supplant pipeline transport, some portion of the CAPEX would merely move from pipeline to rail transport and the total projected capital expenditure across all categories might not change by much. That result would depend on the amount of pipeline capacity that is supplanted by rail transport because rail transport is typically more expensive than pipeline transport.

Exhibit 27: Refining and Oil Products Transport CAPEX (Million 2016$)

Constant Unit Cost Case



Escalating Unit Cost Case



4.2.6 Capital Expenditures for Export Terminals

The scenarios project capital expenditures for liquefied natural gas (LNG) and natural gas liquid (NGL) export facilities ranging from $80 billion to $93 billion from 2018 to 2035. These values equate to $4.5 to $5.1 billion per year (**Exhibit 28**), well above recent historical averages.

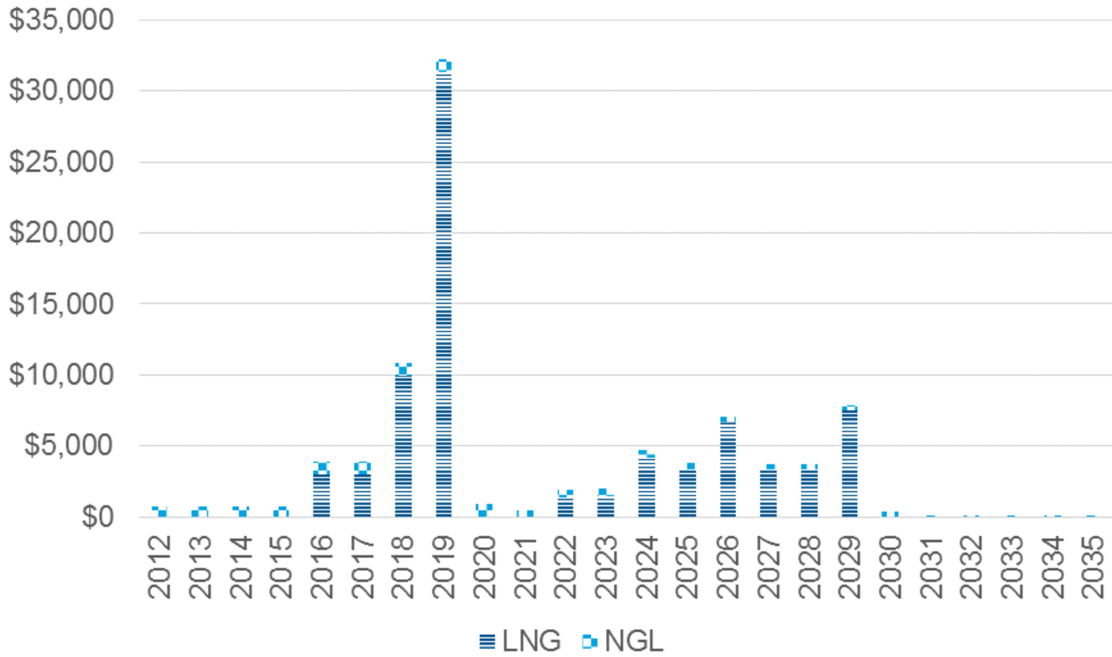
Assuming 15 trains of liquefaction (i.e., 0.5 billion cubic feet per day per year of new capacity) placed into service to support over 10 billion cubic feet per day of exports after 2025, total expenditures for LNG export facilities rise to over $73 to $83 billion from 2018 through 2035. This level of investment equates to an average annual CAPEX of $4.0 to $4.6 billion over the entire projection period. Most new facilities are placed into service along the Gulf Coast at various locations including Sabine Pass, Corpus Christi, Freeport, Cameron and Golden Pass.

Natural gas liquids export facilities added in the cases contribute between $7.6 and $9.7 billion to the total CAPEX. While the dollar value of NGL export facilities is much lower than the expenditures for LNG export facilities, the expenditure supports a significant amount of new NGL export capacity – about 84,000 barrels per day each year or 1.5 million barrels per day throughout the projection.

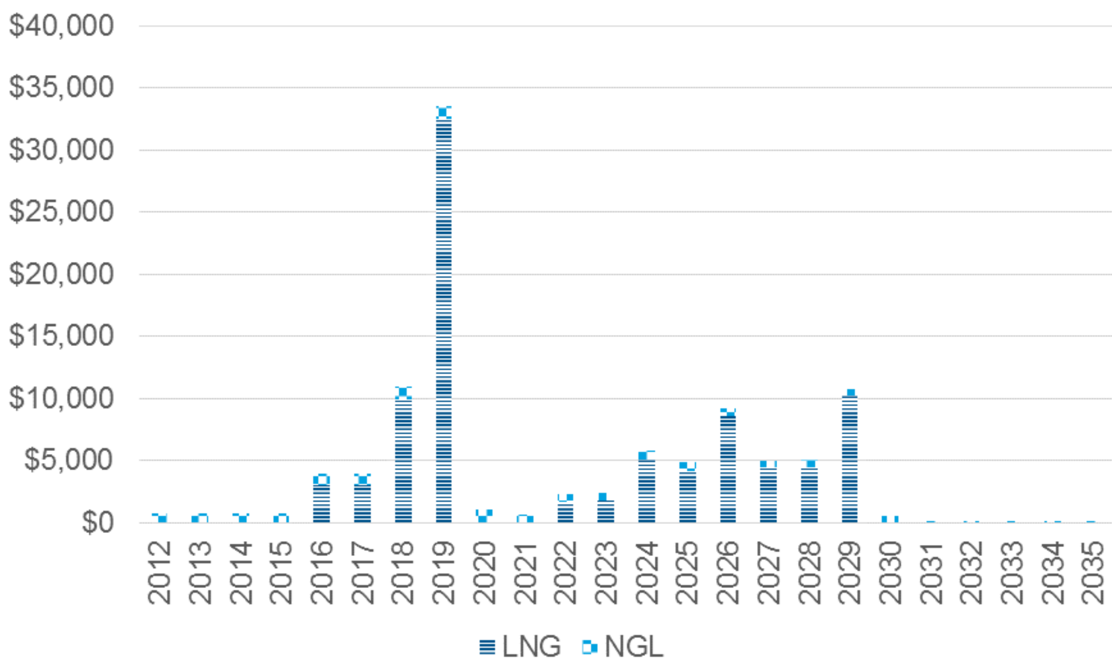
Much of the new NGL capacity reflects propane exports, with some incremental capacity required to support exports of ethane and butane. Even though there is a significant amount of export capability added, the CAPEX is not nearly as large as it is for LNG because liquefaction facilities required to produce the LNG are relatively expensive facilities, compared with the liquids handling, loading and unloading facilities needed to facilitate liquids import and export activity.

Exhibit 28: Liquefied Natural Gas (LNG) and Natural Gas Liquids (NGL) Export Terminal CAPEX (Million 2016$)

Constant Unit Cost Case



Escalating Unit Cost Case



4.3 Summary of Regional Investment in Oil and Gas Infrastructure

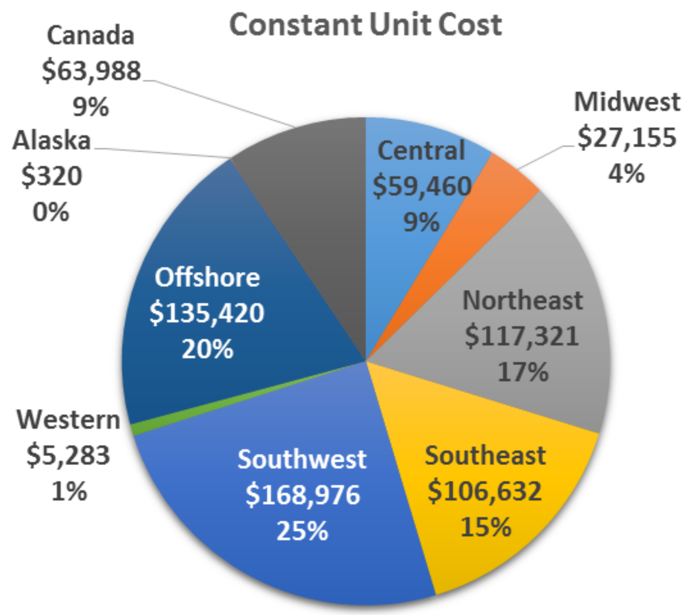
Regionally, the Southwest leads the pack in oil and gas infrastructure development with CAPEX between $169 billion and $217 billion, or 24 to 25 percent of the total investment throughout the projection (**Exhibit 29**). This area is relatively friendly to oil and gas development and already home to a significant amount of infrastructure.

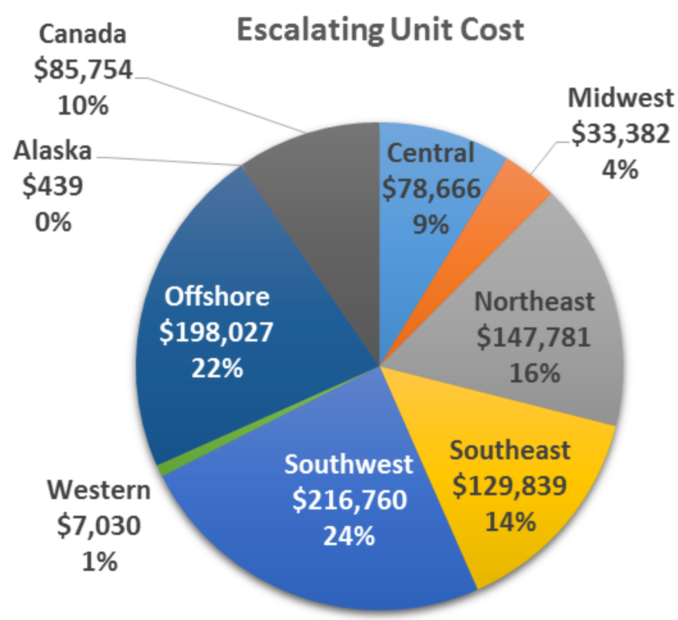
The U.S. Northeast also will see total investment between $117 billion and $148 billion, roughly 17 percent of total U.S. oil and gas infrastructure investment. The focus for this region remains developing and transporting the vast amount of natural gas resource contained in the Marcellus/Utica producing basin. Infrastructure development for this area depends greatly on pipeline project regulatory approvals and market evolution.

The study estimates offshore Gulf of Mexico infrastructure development at $135 billion to $198 billion, or 20 to 22 percent of the total investment. The relatively stable and consistent investment in this area is linked to offshore oil platforms.

Collectively, the other geographic areas account for the remaining $263 billion to $335 billion, or roughly 37 percent of the total investment across the projections. Reasons for development of these other areas are varied, as summarized in the discussion below.

Exhibit 29: Cumulative Regional CAPEX for Oil and Gas Infrastructure, 2018-2035 (Million 2016$)





Central

Total investment in this region will range from $59 billion to $79 billion over the course of the projection, or annual investment of $3.3 billion and $4.4 billion for the Constant Unit Cost and Escalating Unit Cost scenarios, respectively (**Exhibit 30** and **Exhibit 32**). These values amount to roughly 9 percent (**Exhibit 31** and **Exhibit 33**) of the total investment in oil and gas infrastructure across the U.S. and Canada. With roughly 20 percent of the future E&P activity concentrated within the Central region's Bakken and Williston, Greater Green River, Uinta/Piceance, DJ, Powder River and Niobrara basins, most investment is focused on development of surface and lease equipment and gathering and processing facilities. Each of these producing areas has a vast amount of resource remaining to be developed, providing significant opportunity for continued oil and gas infrastructure development across the area.

Midwest

Total investment in this region will range from $27 billion to $33 billion (i.e., roughly 4 percent of the U.S. and Canada total) throughout the projection, or $1.5 billion to $1.9 billion annually. Significant investment for the area is focused on new pipeline projects to move incremental natural gas supplies from the Marcellus and Utica basins into the area. The study also forecasts significant investment in the region's refineries, which are located closer to the Bakken Shale and Western Canada than refineries elsewhere across the U.S. Many Midwest refineries will enhance and upgrade their capabilities to handle increasing volumes of oil from those areas.

Northeast

Total oil and gas infrastructure investment for this region is $117 billion to $148 billion, representing roughly 17 percent of total U.S. investment. Roughly 50 percent of the area's annual investment of $3.4 billion to $4.1 billion is focused on building new gas and NGL pipelines from the Marcellus and Utica producing areas.

Gathering and processing development also accounts for a significant portion of the area's investment, with 10,600 miles of gathering line, 17.7 billion cubic feet per day of gas processing plant capacity, and 0.4 million barrels per day of NGL fractionation capacity developed from 2018 through 2035. In aggregate, the gathering and processing facilities added within this area will account for roughly 8 percent of the total gathering and 46 percent of the total processing capabilities added across the U.S. and Canada.

Southeast

Total investment in this region will range from $107 billion to $130 billion (i.e., roughly 15 percent of the U.S. and Canada total) throughout the projection, or about $6.0 billion to $7.2 billion annually. Roughly 40 percent of the projected investment for the area is focused on new pipeline projects, almost all of which are designed to deliver natural gas to power plants. This area will potentially experience very robust growth in gas-fired power generation as the nation's coal power plants continue to retire. There is also some investment in the area for refinery upgrades and enhancements.

Southwest

The Southwest leads the pack in oil and gas infrastructure development with between $169 billion and $217 billion ($9.4 billion and $12 billion annually), or 24 to 25 percent of the total investment throughout the projection.

Gathering and processing remains a major investment focus, with average annual expenditures ranging from $2.7 to $3.5 billion. The region produces oil, gas, and NGLs, so midstream infrastructure development is expected in each category.

The study forecasts investment in the region's surface and lease equipment from $2.6 billion to $3.6 billion per year. A region friendly to oil and natural gas, the Southwest could see about half of the nation's new producing wells from 2018 through 2035.

Pipeline and export facility investment will range from $3.7 billion to $4.5 billion. Oil pipeline investment will focus on transporting incremental supplies from West Texas to refineries near the Texas Gulf Coast. Gas pipeline investment will focus on feeding LNG export and petrochemical facilities and exports to Mexico. NGL pipeline investment focuses on transport to export terminals, new ethane crackers, and new polypropylene production facilities. LNG export terminals and incremental NGL export capacity will remain concentrated in this region.

The Southwest also sees the most significant investment for oil and gas storage, with annual CAPEX ranging from $128 million to $149 million. This reflects the continued investment in oil tank farms along the Gulf Coast and the favorable geology for high-deliverability salt caverns for natural gas storage.

West

The study forecasts oil and gas infrastructure investment in this region at a modest $5.3 billion to $7.0 billion, accounting for roughly 1 percent of total U.S. and Canadian investment. This investment, equal to about $294 million to $391 million annually, is concentrated on surface and lease equipment.

Offshore Gulf of Mexico

The investment range in the offshore Gulf sits between $135 billion to $198 billion from 2018 through 2035, or $7.5 to $11 billion per year, representing 20 to 22 percent of the total investment across the U.S. and Canada. Investment is almost entirely concentrated in offshore platform development, with the study forecasting roughly 350 MBOE/d of capacity oil platforms being placed in service each year.

Alaska

The study estimates Alaska's oil and gas infrastructure development at roughly $320 to $439 million from 2018 through 2035. Future investment is mostly focused on infrastructure needed to support oil production from the North Slope, which has been declining. This study does not assume additional North Slope development.

Exhibit 30: Projected Annual CAPEX by Region and Category, Constant Unit Cost Case (Million 2016$)

	Central	Midwest	Northeast	Southeast	Southwest	West	Offshore	Alaska	Canada	U.S. and Canada
Surface and Lease Equipment	$1,019	$14	$305	$22	$2,607	$101	$7,505	$7	$745	$12,326
Gathering and Processing	$986	$82	$2,445	$8	$2,710	$38	$18	$9	$945	$7,241
Oil, Gas, and NGL Pipelines	$1,204	$1,322	$3,414	$2,183	$3,259	$66	$1	$0	$1,657	$13,107
Oil and Gas Storage	$19	$21	$48	$62	$128	$0	$0	$0	$93	$372
Refining and Oil Products Transport	$75	$70	$21	$72	$205	$87	$0	$1	$0	$532
Export Terminals	$0	$0	$285	$3,576	$477	$1	$0	$0	$114	$4,454
Total Midstream Investment	$3,303	$1,509	$6,518	$5,924	$9,388	$294	$7,523	$18	$3,555	$38,031

Exhibit 31: Percent of Projected Annual CAPEX by Region and Category, Constant Unit Cost Case

	Central	Midwest	Northeast	Southeast	Southwest	West	Offshore	Alaska	Canada	U.S. and Canada
Surface and Lease Equipment	2.7%	0.0%	0.8%	0.1%	6.9%	0.3%	19.7%	0.0%	2.0%	32.4%
Gathering and Processing	2.6%	0.2%	6.4%	0.0%	7.1%	0.1%	0.0%	0.0%	2.5%	19.0%
Oil, Gas, and NGL Pipelines	3.2%	3.5%	9.0%	5.7%	8.6%	0.2%	0.0%	0.0%	4.4%	34.5%
Oil and Gas Storage	0.0%	0.1%	0.1%	0.2%	0.3%	0.0%	0.0%	0.0%	0.2%	1.0%
Refining and Products Transport	0.2%	0.2%	0.1%	0.2%	0.5%	0.2%	0.0%	0.0%	0.0%	1.4%
Export Terminals	0.0%	0.0%	0.7%	9.4%	1.3%	0.0%	0.0%	0.0%	0.3%	11.7%
Total Midstream Investment	8.7%	4.0%	17.1%	15.6%	24.7%	0.8%	19.8%	0.0%	9.3%	100.0%

Exhibit 32: Projected Annual CAPEX by Region and Category, Escalating Unit Cost Case (Million 2016$)

	Central	Midwest	Northeast	Southeast	Southwest	West	Offshore	Alaska	Canada	U.S. and Canada
Surface and Lease Equipment	$1,408	$20	$424	$31	$3,640	$141	$10,976	$10	$1,052	$17,703
Gathering and Processing	$1,332	$106	$3,283	$11	$3,540	$54	$24	$13	$1,301	$9,666
Oil, Gas, and NGL Pipelines	$1,514	$1,615	$4,123	$2,885	$3,886	$84	$1	$0	$2,167	$16,275
Oil and Gas Storage	$22	$32	$55	$82	$149	$0	$0	$0	$105	$446
Refining and Oil Products Transport	$93	$81	$25	$85	$239	$110	$0	$1	$0	$633
Export Terminals	$0	$0	$299	$4,120	$588	$2	$0	$0	$140	$5,148
Total Midstream Investment	$4,370	$1,855	$8,210	$7,213	$12,042	$391	$11,001	$24	$4,764	$49,871

Exhibit 33: Percent of Projected Annual CAPEX by Region and Category, Escalating Unit Cost Case

	Central	Midwest	Northeast	Southeast	Southwest	West	Offshore	Alaska	Canada	U.S. and Canada
Surface and Lease Equipment	2.8%	0.0%	0.9%	0.1%	7.3%	0.3%	22.0%	0.0%	2.1%	35.5%
Gathering and Processing	2.7%	0.2%	6.6%	0.0%	7.1%	0.1%	0.0%	0.0%	2.6%	19.4%
Oil, Gas, and NGL Pipelines	3.0%	3.2%	8.3%	5.8%	7.8%	0.2%	0.0%	0.0%	4.3%	32.6%
Oil and Gas Storage	0.0%	0.1%	0.1%	0.2%	0.3%	0.0%	0.0%	0.0%	0.2%	0.9%
Refining and Products Transport	0.2%	0.2%	0.0%	0.2%	0.5%	0.2%	0.0%	0.0%	0.0%	1.3%
Export Terminals	0.0%	0.0%	0.6%	8.3%	1.2%	0.0%	0.0%	0.0%	0.3%	10.3%
Total Midstream Investment	8.8%	3.7%	16.5%	14.5%	24.1%	0.8%	22.1%	0.0%	9.6%	100.0%

5 Results of the Economic Impact Analysis

Oil and gas infrastructure investment will benefit the U.S. economy. Specifically, it will increase both employment and Gross State Products. To assess economic benefits that result from the capital expenditures discussed above, the study applies IMPLAN, a widely used economic impact analysis system. IMPLAN considers both multiplier effects and leakage to markets elsewhere, as it estimates impacts across three different categories:

- **Direct Employment and Investment** – represents economic impacts (e.g., employment or output changes) due to the direct investments, such as payments to companies in the relevant industries for asset categories that apply directly to this study.
- **Indirect Employment and Expenditures** – represents economic impacts due to the industry inter-linkages caused by the iteration of industries purchasing from other industries, brought about by changes in final demands (e.g., when pipeline manufacturers purchase steel from another company).
- **Induced Employment and Expenditures** – represents the economic impacts on local industries due to consumers' consumption expenditures arising from the new household incomes that are generated by the direct and indirect effects of the final demand changes (e.g., a worker purchases new clothing or purchases food in restaurants).

With total oil and gas infrastructure investment of $685 billion to $898 billion, or $38 billion to $50 billion annually, the IMPLAN analysis projects that total direct, indirect and induced employment per year across the U.S. and Canada of 725,000 (**Exhibit 34**). These numbers are only for employment associated with oil and gas infrastructure development. They do not include jobs more broadly across the upstream and downstream segments of the industry, nor do they include jobs related to operating and maintaining oil and gas infrastructure, each of which would add millions to the U.S. labor pool. Nevertheless, the results suggest that oil and gas infrastructure development represents a significant engine for future economic growth.

The projections also show that infrastructure development will directly employ 242,000 employees. These include employees at companies directly involved with the planning, designing and construction of the infrastructure. However, the impacts outside of the companies directly involved in infrastructure development are also significant, with 189,500 indirect jobs and 293,000 induced jobs. In other words, benefits are far reaching across the U.S. economy.

Infrastructure development drives employment across the country, even as far away as Hawaii. The top five states for employment associated with infrastructure development are Ohio, Texas, Louisiana, Pennsylvania, and California, in that order.

This economic impact analysis also projects U.S. and Canada Gross Domestic Product (GDP) associated with oil and gas infrastructure development at $1.3 trillion for the 2018 to 2035 projection period (**Exhibit 35**). That equates to about $70 billion in average annual contributions to U.S. and Canada GDP. Average annual average tables for Gross State Product (GSP) and taxes are shown in Appendix D.

Based on Gross State Product information provided in the exhibits, the top five beneficiaries of investment include Texas, Louisiana, Pennsylvania, California, and Ohio, in that order. Although California does not gain much direct employment from the development of oil and gas infrastructure, it experiences large gains in induced employment because of the interconnectedness of its economy with the rest of the county. There are also billions of dollars of benefits to all other states across the U.S.

Oil and gas infrastructure investment also boosts federal and state tax coffers. The study forecasts federal taxes associated with oil and gas infrastructure development at $238 billion from 2018 to 2035, or an average$13 billion annually. This investment also raises state and local taxes by a total $204 billion from 2018 through 2035, or an average$11 billion annually.

Oil and gas infrastructure investment flows throughout the U.S. economy, having wide-ranging benefits for millions of Americans. This analysis excludes values associated with operating and maintaining the infrastructure, and it also excludes values associated with the upstream and downstream segments of the business. However, the oil and gas infrastructure discussed is critical to those sectors as well. Failure to develop oil and gas infrastructure would stymie upstream and downstream development and related economic benefits.

Oil and gas infrastructure development also fosters delivery of lower cost energy to households and businesses, another positive economic impact not considered in this analysis. A more complete and thorough economic impact analysis would consider such benefits, as well as the benefits for the upstream and downstream segments of the energy business, in addition to the economic impacts that are discussed herein. Collectively, such economic benefits would be multiples of impacts shown here.

Exhibit 34: Projected Employment (Jobs per Year)

	Average 2013-2017				Average 2018-2035			
	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total
U.S. & Canada	**306,384**	**240,269**	**370,810**	**917,463**	**242,216**	**189,524**	**293,173**	**724,913**
U.S.	**271,840**	**211,979**	**329,903**	**813,722**	**220,039**	**171,381**	**266,886**	**658,305**
Canada	**34,544**	**28,290**	**40,907**	**103,741**	**22,177**	**18,143**	**26,288**	**66,608**
Alabama	1,788	2,511	3,978	**8,277**	2,034	2,327	3,368	**7,728**
Alaska	510	240	691	**1,441**	253	123	512	**888**
Arizona	271	1,494	4,384	**6,149**	127	1,159	3,521	**4,807**
Arkansas	2,924	2,055	2,707	**7,686**	1,034	1,026	1,828	**3,888**
California	6,736	8,598	32,076	**47,410**	3,013	5,867	25,230	**34,110**
Colorado	7,364	4,478	6,121	**17,963**	6,449	3,885	5,091	**15,425**
Connecticut	77	1,450	4,152	**5,679**	144	1,212	3,380	**4,737**
Delaware	908	568	922	**2,398**	608	409	704	**1,722**
District of Columbia	242	118	684	**1,045**	83	41	524	**648**
Florida	2,437	2,727	13,056	**18,220**	1,968	2,205	10,561	**14,734**
Georgia	786	1,618	6,262	**8,667**	834	1,370	5,139	**7,343**
Hawaii	0	27	900	**927**	0	22	728	**750**
Idaho	320	500	1,125	**1,945**	227	391	901	**1,518**
Illinois	7,636	7,660	13,188	**28,484**	1,282	3,890	9,313	**14,485**
Indiana	2,815	5,424	7,046	**15,285**	1,109	3,838	5,372	**10,319**
Iowa	711	1,197	2,607	**4,515**	295	839	2,029	**3,163**
Kansas	5,406	3,399	3,802	**12,607**	3,040	2,116	2,705	**7,860**
Kentucky	1,484	2,018	3,477	**6,979**	4,054	3,040	3,554	**10,648**
Louisiana	69,981	32,107	24,078	**126,166**	53,691	24,388	18,753	**96,831**
Maine	68	685	1,178	**1,931**	117	584	969	**1,670**
Maryland	392	1,169	5,065	**6,626**	1,275	1,350	4,391	**7,016**
Massachusetts	81	2,311	6,892	**9,283**	160	1,914	5,600	**7,674**
Michigan	2,744	5,644	8,996	**17,384**	655	3,805	6,858	**11,319**
Minnesota	1,519	2,528	5,225	**9,272**	782	1,843	4,093	**6,717**
Mississippi	2,735	1,598	2,323	**6,655**	1,770	1,085	1,753	**4,607**
Missouri	692	1,649	4,385	**6,727**	357	1,238	3,490	**5,085**
Montana	1,650	860	1,062	**3,572**	1,717	894	956	**3,567**
Nebraska	720	783	1,702	**3,205**	254	479	1,285	**2,018**
Nevada	29	162	1,642	**1,832**	9	124	1,324	**1,457**
New Hampshire	69	416	1,220	**1,705**	118	366	1,003	**1,487**
New Jersey	3,627	3,361	8,997	**15,984**	1,365	1,987	6,841	**10,193**
New Mexico	7,555	3,885	3,193	**14,633**	9,631	4,904	3,517	**18,052**
New York	5,437	7,938	19,943	**33,318**	2,281	5,397	15,555	**23,233**
North Carolina	686	2,976	7,144	**10,807**	417	2,340	5,742	**8,498**
North Dakota	6,793	3,552	2,660	**13,006**	4,108	2,264	1,745	**8,117**
Ohio	16,175	13,931	14,912	**45,018**	10,188	9,899	11,258	**31,345**
Oklahoma	11,393	7,351	6,615	**25,360**	5,318	4,066	4,302	**13,686**
Oregon	309	1,290	3,055	**4,653**	13	935	2,404	**3,351**
Pennsylvania	21,804	16,602	18,045	**56,450**	19,403	14,317	14,998	**48,718**
Rhode Island	69	417	946	**1,432**	116	366	781	**1,263**
South Carolina	566	3,684	4,759	**9,009**	924	3,206	3,971	**8,101**
South Dakota	1,501	946	1,066	**3,513**	340	339	628	**1,308**
Tennessee	1,478	2,568	5,164	**9,210**	4,189	3,551	4,957	**12,698**
Texas	56,728	33,657	36,904	**127,289**	59,499	33,214	33,912	**126,626**
Utah	2,021	1,463	2,376	**5,859**	483	633	1,602	**2,719**
Vermont	69	256	559	**884**	119	238	469	**826**
Virginia	707	1,942	6,816	**9,466**	1,897	2,220	5,858	**9,976**
Washington	2,527	2,364	6,348	**11,238**	602	1,287	4,703	**6,592**
West Virginia	5,311	3,376	2,824	**11,512**	7,803	4,446	3,195	**15,445**
Wisconsin	1,078	2,795	5,219	**9,092**	549	2,114	4,124	**6,788**
Wyoming	2,911	1,633	1,412	**5,955**	3,333	1,829	1,388	**6,550**

Exhibit 35: Total Contribution to Gross State Product and Taxes (Million 2016$)

	Total 2013-2017				Total 2018-2035			
	GDP	State/Local Tax	Federal Tax	Total Tax	GDP	State/Local Tax	Federal Tax	Total Tax
U.S. & Canada	$444,326	$70,277	$76,569	$146,846	$1,262,215	$203,986	$237,740	$441,725
U.S.	$393,290	$60,284	$70,428	$130,712	$1,144,147	$180,868	$223,364	$404,232
Canada	$51,036	$9,993	$6,141	$16,134	$118,068	$23,118	$14,376	$37,493
Alabama	$4,758	$737	$850	$1,587	$15,184	$2,427	$2,967	$5,394
Alaska	$586	$111	$105	$215	$1,337	$261	$261	$522
Arizona	$3,791	$494	$677	$1,172	$10,790	$1,455	$2,105	$3,560
Arkansas	$3,516	$524	$628	$1,152	$7,184	$1,108	$1,405	$2,513
California	$24,809	$4,015	$4,441	$8,457	$66,578	$11,149	$12,994	$24,143
Colorado	$7,741	$1,176	$1,389	$2,564	$23,960	$3,759	$4,686	$8,445
Connecticut	$3,640	$500	$652	$1,152	$10,777	$1,532	$2,102	$3,634
Delaware	$1,062	$182	$191	$374	$2,799	$494	$544	$1,038
District of Columbia	$435	$83	$79	$162	$1,012	$198	$197	$395
Florida	$9,047	$1,188	$1,624	$2,812	$26,334	$3,572	$5,143	$8,715
Georgia	$4,754	$631	$855	$1,487	$14,275	$1,965	$2,772	$4,737
Hawaii	$443	$82	$79	$161	$1,291	$246	$252	$498
Idaho	$1,093	$154	$195	$350	$3,110	$454	$610	$1,064
Illinois	$14,861	$2,284	$2,673	$4,956	$32,049	$5,097	$6,251	$11,348
Indiana	$9,617	$1,464	$1,722	$3,186	$25,276	$3,979	$4,931	$8,910
Iowa	$2,591	$452	$467	$919	$6,898	$1,242	$1,344	$2,586
Kansas	$5,593	$876	$997	$1,873	$13,153	$2,133	$2,575	$4,708
Kentucky	$3,955	$593	$710	$1,303	$17,954	$2,788	$3,533	$6,320
Louisiana	$47,486	$6,882	$8,477	$15,358	$131,111	$19,843	$25,748	$45,592
Maine	$1,358	$219	$244	$462	$4,092	$681	$798	$1,478
Maryland	$3,694	$535	$663	$1,198	$12,932	$1,943	$2,499	$4,442
Massachusetts	$5,929	$836	$1,062	$1,898	$17,466	$2,546	$3,408	$5,954
Michigan	$10,741	$1,647	$1,925	$3,572	$27,663	$4,389	$5,399	$9,788
Minnesota	$5,375	$908	$964	$1,873	$14,580	$2,549	$2,846	$5,395
Mississippi	$2,827	$505	$507	$1,012	$7,193	$1,328	$1,404	$2,732
Missouri	$3,946	$539	$710	$1,249	$11,014	$1,555	$2,150	$3,705
Montana	$1,431	$208	$255	$463	$5,071	$748	$983	$1,731
Nebraska	$1,675	$261	$302	$563	$4,123	$663	$803	$1,466
Nevada	$942	$131	$169	$300	$2,711	$392	$529	$921
New Hampshire	$1,053	$131	$189	$320	$3,204	$412	$624	$1,036
New Jersey	$7,948	$1,208	$1,416	$2,624	$19,573	$3,073	$3,812	$6,885
New Mexico	$5,698	$1,088	$1,016	$2,105	$24,978	$4,889	$4,860	$9,749
New York	$18,369	$3,827	$3,293	$7,120	$48,521	$10,458	$9,457	$19,915
North Carolina	$6,802	$1,035	$1,221	$2,256	$19,472	$3,068	$3,803	$6,871
North Dakota	$5,168	$1,193	$923	$2,116	$11,913	$2,767	$2,318	$5,086
Ohio	$22,586	$3,536	$4,093	$7,629	$59,034	$9,544	$11,522	$21,066
Oklahoma	$11,165	$1,561	$1,996	$3,556	$23,600	$3,401	$4,599	$8,001
Oregon	$2,937	$495	$526	$1,021	$8,008	$1,398	$1,563	$2,961
Pennsylvania	$27,065	$3,985	$4,831	$8,816	$82,238	$12,484	$16,043	$28,526
Rhode Island	$929	$149	$167	$316	$2,839	$471	$553	$1,024
South Carolina	$6,575	$1,129	$1,179	$2,308	$20,168	$3,578	$3,938	$7,516
South Dakota	$1,535	$193	$277	$470	$2,444	$316	$473	$788
Tennessee	$5,383	$672	$966	$1,639	$22,425	$2,900	$4,406	$7,306
Texas	$54,749	$7,418	$9,770	$17,188	$190,918	$26,892	$37,222	$64,114
Utah	$2,746	$435	$489	$924	$5,301	$869	$1,034	$1,903
Vermont	$558	$93	$100	$194	$1,768	$304	$344	$648
Virginia	$5,412	$751	$971	$1,722	$18,711	$2,670	$3,622	$6,292
Washington	$5,683	$829	$1,021	$1,850	$13,264	$1,999	$2,587	$4,586
West Virginia	$5,052	$919	$908	$1,827	$22,510	$4,226	$4,398	$8,624
Wisconsin	$5,701	$876	$1,023	$1,899	$15,808	$2,513	$3,087	$5,599
Wyoming	$2,477	$543	$440	$984	$9,533	$2,140	$1,860	$4,000

Exhibit 36: Average Contribution to Gross State Product and Taxes (Million 2016$)

	Average 2013-2017				Average 2018-2035			
	GDP	State/Local Tax	Federal Tax	Total Tax	GDP	State/Local Tax	Federal Tax	Total Tax
U.S. & Canada	**$88,865**	**$14,055**	**$15,314**	**$29,369**	**$70,123**	**$11,333**	**$13,208**	**$24,540**
U.S.	**$78,658**	**$12,057**	**$14,086**	**$26,142**	**$63,564**	**$10,048**	**$12,409**	**$22,457**
Canada	**$10,207**	**$1,999**	**$1,228**	**$3,227**	**$6,559**	**$1,284**	**$799**	**$2,083**
Alabama	$952	$147	$170	**$317**	$844	$135	$165	**$300**
Alaska	$117	$22	$21	**$43**	$74	$14	$14	**$29**
Arizona	$758	$99	$135	**$234**	$599	$81	$117	**$198**
Arkansas	$703	$105	$126	**$230**	$399	$62	$78	**$140**
California	$4,962	$803	$888	**$1,691**	$3,699	$619	$722	**$1,341**
Colorado	$1,548	$235	$278	**$513**	$1,331	$209	$260	**$469**
Connecticut	$728	$100	$130	**$230**	$599	$85	$117	**$202**
Delaware	$212	$36	$38	**$75**	$155	$27	$30	**$58**
District of Columbia	$87	$17	$16	**$32**	$56	$11	$11	**$22**
Florida	$1,809	$238	$325	**$562**	$1,463	$198	$286	**$484**
Georgia	$951	$126	$171	**$297**	$793	$109	$154	**$263**
Hawaii	$89	$16	$16	**$32**	$72	$14	$14	**$28**
Idaho	$219	$31	$39	**$70**	$173	$25	$34	**$59**
Illinois	$2,972	$457	$535	**$991**	$1,780	$283	$347	**$630**
Indiana	$1,923	$293	$344	**$637**	$1,404	$221	$274	**$495**
Iowa	$518	$90	$93	**$184**	$383	$69	$75	**$144**
Kansas	$1,119	$175	$199	**$375**	$731	$119	$143	**$262**
Kentucky	$791	$119	$142	**$261**	$997	$155	$196	**$351**
Louisiana	$9,497	$1,376	$1,695	**$3,072**	$7,284	$1,102	$1,430	**$2,533**
Maine	$272	$44	$49	**$92**	$227	$38	$44	**$82**
Maryland	$739	$107	$133	**$240**	$718	$108	$139	**$247**
Massachusetts	$1,186	$167	$212	**$380**	$970	$141	$189	**$331**
Michigan	$2,148	$329	$385	**$714**	$1,537	$244	$300	**$544**
Minnesota	$1,075	$182	$193	**$375**	$810	$142	$158	**$300**
Mississippi	$565	$101	$101	**$202**	$400	$74	$78	**$152**
Missouri	$789	$108	$142	**$250**	$612	$86	$119	**$206**
Montana	$286	$42	$51	**$93**	$282	$42	$55	**$96**
Nebraska	$335	$52	$60	**$113**	$229	$37	$45	**$81**
Nevada	$188	$26	$34	**$60**	$151	$22	$29	**$51**
New Hampshire	$211	$26	$38	**$64**	$178	$23	$35	**$58**
New Jersey	$1,590	$242	$283	**$525**	$1,087	$171	$212	**$383**
New Mexico	$1,140	$218	$203	**$421**	$1,388	$272	$270	**$542**
New York	$3,674	$765	$659	**$1,424**	$2,696	$581	$525	**$1,106**
North Carolina	$1,360	$207	$244	**$451**	$1,082	$170	$211	**$382**
North Dakota	$1,034	$239	$185	**$423**	$662	$154	$129	**$283**
Ohio	$4,517	$707	$819	**$1,526**	$3,280	$530	$640	**$1,170**
Oklahoma	$2,233	$312	$399	**$711**	$1,311	$189	$256	**$444**
Oregon	$587	$99	$105	**$204**	$445	$78	$87	**$165**
Pennsylvania	$5,413	$797	$966	**$1,763**	$4,569	$694	$891	**$1,585**
Rhode Island	$186	$30	$33	**$63**	$158	$26	$31	**$57**
South Carolina	$1,315	$226	$236	**$462**	$1,120	$199	$219	**$418**
South Dakota	$307	$39	$55	**$94**	$136	$18	$26	**$44**
Tennessee	$1,077	$134	$193	**$328**	$1,246	$161	$245	**$406**
Texas	$10,950	$1,484	$1,954	**$3,438**	$10,607	$1,494	$2,068	**$3,562**
Utah	$549	$87	$98	**$185**	$294	$48	$57	**$106**
Vermont	$112	$19	$20	**$39**	$98	$17	$19	**$36**
Virginia	$1,082	$150	$194	**$344**	$1,040	$148	$201	**$350**
Washington	$1,137	$166	$204	**$370**	$737	$111	$144	**$255**
West Virginia	$1,010	$184	$182	**$365**	$1,251	$235	$244	**$479**
Wisconsin	$1,140	$175	$205	**$380**	$878	$140	$171	**$311**
Wyoming	$495	$109	$88	**$197**	$530	$119	$103	**$222**

6 Conclusions

About $316 billion – or $63 billion a year – was invested in oil and gas infrastructure in the U.S. and Canada over the past five years, leading some to question whether such robust investments could continue.

Recent declines in oil and natural gas prices, driven by supply-demand dynamics, among other factors, have created an environment of great uncertainty for future energy investments, including midstream energy investments. This study investigates oil and gas infrastructure investment and concludes that strong infrastructure development is likely for a prolonged period. This investment will provide significant benefits to the U.S. economy.

To assess infrastructure development, the study considers both a Constant per Unit Cost Case and an Escalating per Unit Cost Case. Each of these scenarios are plausible representations of how the market may evolve over time. They provide the basis for infrastructure needs, by type of infrastructure, and by region, while evaluating the effects of different cost scenarios.

In each scenario, growth in shale gas and tight oil production continues, and production growth from cost-effective plays like the Marcellus and Utica in the U.S. Northeast and the Permian Basin in West Texas drive oil and gas infrastructure development. Strong supply growth will continue to foster increased output from U.S. refineries, development of NGL and LNG exports, incremental exports of natural gas to Mexico, new petrochemical facilities spread across the Northeast and near the Gulf Coast and increases in gas-fired power generation. These factors, in turn, support oil and gas infrastructure development.

Summary of Scenario Trends

The supply and demand trends that underpin the study's scenarios and infrastructure development are summarized below:

- The scenarios project significant supply and market growth.
- In aggregate, U.S. and Canada oil production increases by 5.6 million barrels per day. Tight oil supplies are a focus for development.
- Natural gas production grows from roughly 90 billion cubic feet per day at present to 130 billion cubic feet per day by 2035.
- NGL production grows by over 72 percent reaches 7.8 million barrels per day by 2035.
- U.S. and Canada refinery runs increase from 18.8 million barrels per day at present to 20.5 million barrels per day by 2035, driven by development of U.S. tight oil supplies.
- LNG exports, exports to Mexico, as well as a growth in natural gas as a feedstock in petrochemical facilities and as a fuel for power generation underpins a strong growth in the natural gas market.
- New ethane crackers and polypropylene facilities spur NGL market growth.
- 7.7 million barrels per day of new oil transport capacity enters service in each of the scenarios.

- 57 billion cubic feet per day of new natural gas transport capacity is needed to support gas production and associated market growth projected through 2035.
- 3.6 million barrels per day of new NGL transport capacity is needed to support NGL production and associated market growth projected through 2035.

Summary of Projected Infrastructure Development

The study projects total capital expenditures for oil and gas infrastructure from 2018 to 2035 at $685 billion and $898 billion, or $38 billion to $50 billion per year. In the Constant Unit Cost Case, natural gas infrastructure development represents roughly 54 percent of total investment, compared with roughly 39 percent for oil infrastructure development. In the Escalating Unit Cost Case, natural gas infrastructure development falls to 52 percent of the total investment, while oil infrastructure development rises to 42 percent of the total, and NGL infrastructure development remains at about the same percent as in the Constant Unit Cost Case or 6 percent.

A summary of infrastructure investment by category follows:

- Surface and lease Equipment accounts for the largest portion of infrastructure development, with a CAPEX of $222 billion to $319 billion over the investment horizon. The CAPEX is split between onshore and offshore development, with investment in lease equipment for an average of 28,510 new wells and seven new offshore oil production platforms each year.
- Oil, gas and NGL pipelines account for total CAPEX of $236 billion to $293 billion throughout the projection. Within this infrastructure category, investment is greatest for natural gas pipelines, with a CAPEX totaling $154 billion to $190 billion throughout the projection. Roughly 1,450 miles of natural gas pipeline are forecast each year, with a total of 26,000 miles put in place throughout the projection.
- Gathering and processing sees total CAPEX of $130 billion to $174 billion over the projection. The scenarios project the addition each year of an average 7,700 miles of gathering line, 700,000 horsepower of compression, 2.1 billion cubic feet per day of processing plant capacity, and 200,000 barrels per day of fractionation plant capacity through the forecast period.
- LNG and NGL exports CAPEX totals $80 billion to $93 billion. The scenarios forecast new LNG export capacity of 13 billion cubic feet per day and new NGL exports capacity of 1.5 million barrels per day.
- Refining and oil products transport CAPEX totals $9.6 billion to $11.4 billion during the projection.
- Oil and gas storage investment totals $6.7 billion to $8 billion, with much of the investment focused on development of new natural gas storage injection and withdrawal wells.

Regionally, the largest portion of infrastructure development occurs in the Southwest, with investment for the area totaling $169 billion to $217 billion over the forecast period. Investment for this area is widespread across all infrastructure categories. The Northeast ranks second, with total investment of $117 billion to $148 billion, largely to transport Marcellus and Utica production to markets and to support gathering and processing. Offshore investment ranks third among the regions, with a total CAPEX of $135 billion to $198 billion. Collectively, all other areas project total investment in oil and gas infrastructure of $263 billion to $335 billion.

Summary of the Economic Impact Analysis

The study also assesses economic benefits of the projected infrastructure development. Economic benefits are highlighted below:

- The total investment of $685 to $898 billion adds $1.3 trillion to U.S. and Canadian GDP from 2018 through 2035.
- Gross State Products increase across the U.S., with Texas, Louisiana, Pennsylvania, California, and Ohio, in that order, benefiting the most.
- Federal taxes associated with infrastructure development will total $238 billion, and state and local taxes associated with development will sum to $204 billion from 2018 through 2035.
- The level of employment (i.e., the number of jobs) supported by infrastructure development averages 725,000 each year throughout the projection including 242,000 direct jobs. Employment impacts are widespread across the U.S. as there are also indirect and induced labor impacts included in the job totals.
- These employment and GSP benefits do not consider employment in the upstream and downstream portions of the oil and gas business, nor do they consider the operation and maintenance of the infrastructure. Those unconsidered segments would account for millions of jobs and significant contribution to GSP, which would add to the totals discussed here.
- Infrastructure development will have wide-ranging benefits for millions of Americans. The midstream business is critical to the growth of the upstream and downstream portions of the oil and gas business. Without adequate infrastructure to support processing and transport of oil and gas, the upstream and downstream will develop less fully over time, lowering economic benefits. Oil and gas infrastructure development also fosters delivery of lower-cost energy to households and businesses, which is another positive economic impact that has not been considered in this analysis.

Appendix A: ICF Modeling Tools

Gas Market Model (GMM)

ICF's Gas Market Model (GMM) is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed by Energy and Environmental Analysis, Inc., now a wholly owned business unit within ICF, in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace.

The GMM has been used to complete strategic planning studies for many private sector companies. The different studies include:

- Analyses of different pipeline expansions;
- Measuring the impact of gas-fired power generation growth;
- Assessing the impact of low and high gas supply; and
- Assessing the impact of different regulatory environments.

In addition to its use for strategic planning studies, the model has been widely used by a number of institutional clients and advisory councils, including the recent Interstate Natural Gas Association of America (INGAA) study. The model was also the primary tool used to complete the widely referenced study on the North American Gas market for the National Petroleum Council in 2003.

GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

There are nine different components of ICF's model, as shown in (**Exhibit 37**). The inputs for the model are provided through a "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

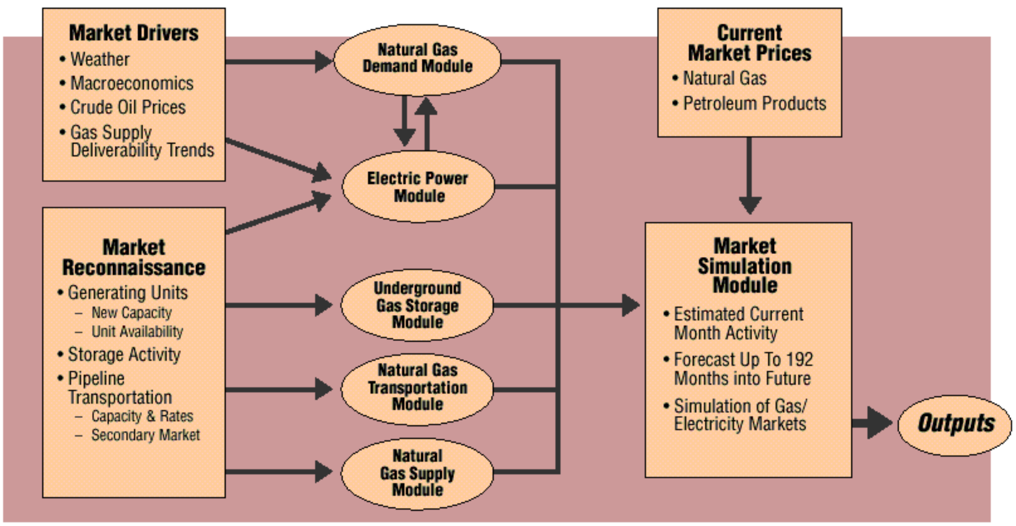
Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. The supply side of the equation includes prices determined by production and storage price curves that reflect prices as a function of production and storage utilization (**Exhibit 38**). Total U.S. and Canadian gas supplies include production, LNG imports, and storage withdrawals (in the withdrawal season only).[1] Gas production is solved in 81 distinct regions throughout the United States and Canada and is represented by both short- and long-run supply curves. In the short run (i.e., the current month), gas production is bound by the amount of available productive capacity. In the long run, productive capacity changes as a function of the available gas resource, the cost of development, and the solved gas price. North American LNG imports and exports are exogenously

[1] Storage withdrawals are solved within the model based on "storage supply curves" that reflect the level of withdrawals relative to gas prices. The curves have been fit to historical price and withdrawal data.

specified by the selected scenario. For each modeling, ICF includes its own projection of North American LNG imports and export by terminal.

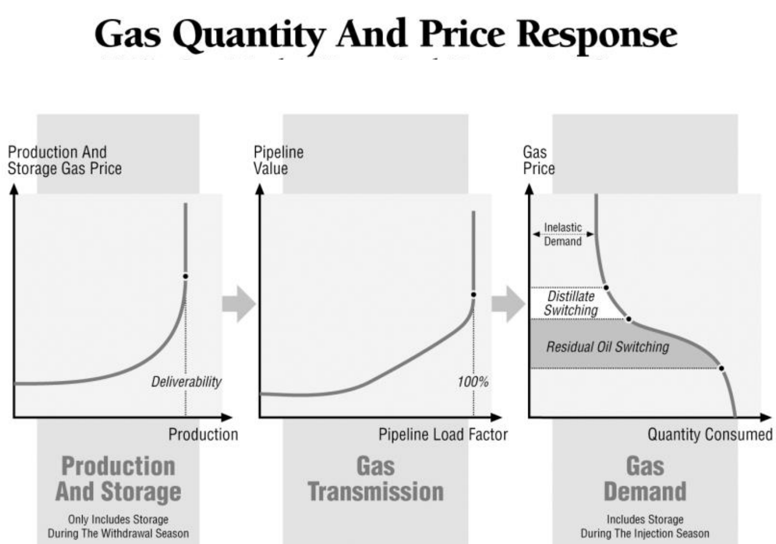
Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of the load factor of the pipeline corridor. The structure of the transmission network is shown in (**Exhibit 39**). The discount curves have been empirically fit to historic basis values and pipeline load factors on each pipeline corridor. Pipeline capacity expansions are exogenously specified for each scenario.

Exhibit 37: GMM Structure



Source: ICF GMM®

Exhibit 38: Natural Gas Supply and Demand Curves in the GMM



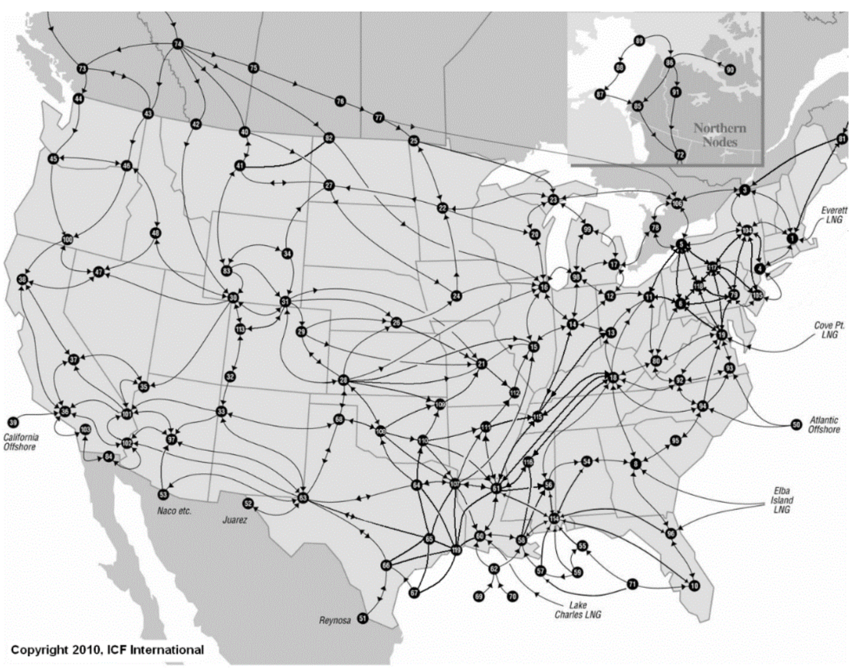
Source: ICF GMM®

On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The gas demand routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The electric power module solves for the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The GMM forecast for power generation is consistent with ICF's Integrated Planning Model (IPM®), and the GMM power module allows for elasticity around IPM results to allow for seasonal/monthly variations. The GMM provides IPM with gas supply curves and basis that is used to determine gas prices for power plants within the IPM framework. The demand forecast for gas in the power sector from the IPM is then used as a benchmark to iterate both models until the gas prices and gas demand from power plants are converged in both models. Furthermore, IPM provides coal and oil retirements, and generation forecast from nuclear, hydro, and non-hydro renewables that is used in the GMM electric power model.

The GMM balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply, demand, and transportation curves. The model nodes are tied together by a series of network links in the gas transportation module. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import levels. The model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and imports to Mexico) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and exports to Mexican) at each of the nodes and gas prices are solved for in the market simulation module.

Unlike other commercially available models for the gas industry, ICF does significant back casting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

Exhibit 39: GMM Transmission Network



Source: ICF GMM®

Detailed Production Report (DPR)

ICF's Detailed Production Report (DPR) is a gas and oil vintage well production model that provides a complete outlook for U.S. and Canada natural gas, natural gas liquids (NGLs), and crude oil (**Exhibit 40**). The DPR presents annual production projections for more than 50 basins throughout the U.S. and Canada and includes total production for both the U.S. and Canada. The report's gas production projections are linked to ICF's Natural Gas-Strategic Outlook, which provides additional insight into the future of the North American natural gas market.

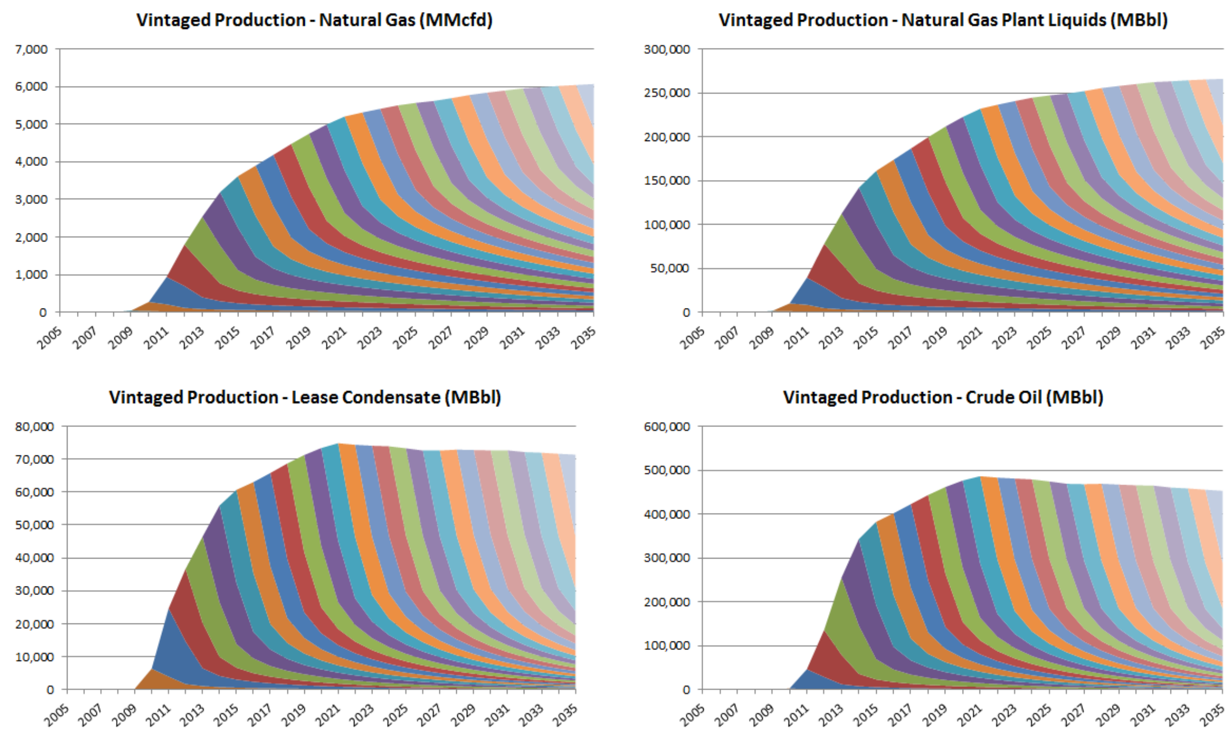
The DPR contains many findings that will be of interest to oil and gas producers, field services companies, and the investment community, including:

- Projected gas, oil, and NGL production by year and by region through 2035.
- Projected gas and oil well activity by year and region through 2035.
- Vintage production charts for each region, showing how production changes over time.
- Estimated ultimate recovery (EUR) statistics for oil, gas, and NGLs wells by region.

The DPR was developed by ICF in the 2011 and its forecasts have been widely used by a number of institutional clients and advisory councils. INGAA midstream infrastructure studies in 2011, 2014, and 2016 relied on the DPR for natural gas, NGL, and oil production trends based on projections of gas and oil drilling activity to assess midstream infrastructure needs in the U.S. and Canada through 2035.

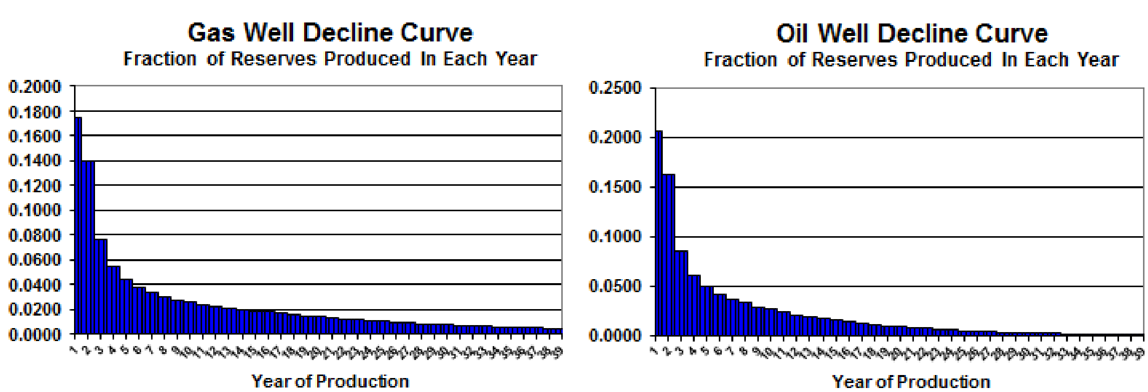
The DPR's historical gas/oil well completions, gas/NGLs/crude oil production, and gas-to-liquids ratio are calibrated to most recent statistics. The historical data is also used to estimate gas/NGLs/crude oil EURs. The main drivers for DPR forecasts are gas production forecasts from ICF's Gas Market Model (GMM) and expected gas and oil well production decline curves (**Exhibit 41**). The GMM node-level annual gas production is mapped to each of the 56 DPR plays/production basins and broken out by gas resource type (**Exhibit 42**). DPR projections are also affected by assumptions for expected gas versus oil directed drilling ratio over time, EUR improvements due to advancement in horizontal drilling and hydraulic fracturing technology, EUR reductions that occur as drilling activities move away from sweet spots, and changes to production decline profiles due to changes in production operation such as "well throttling" implemented to improve EURs.

Exhibit 40: Example Vintage Production from DPR



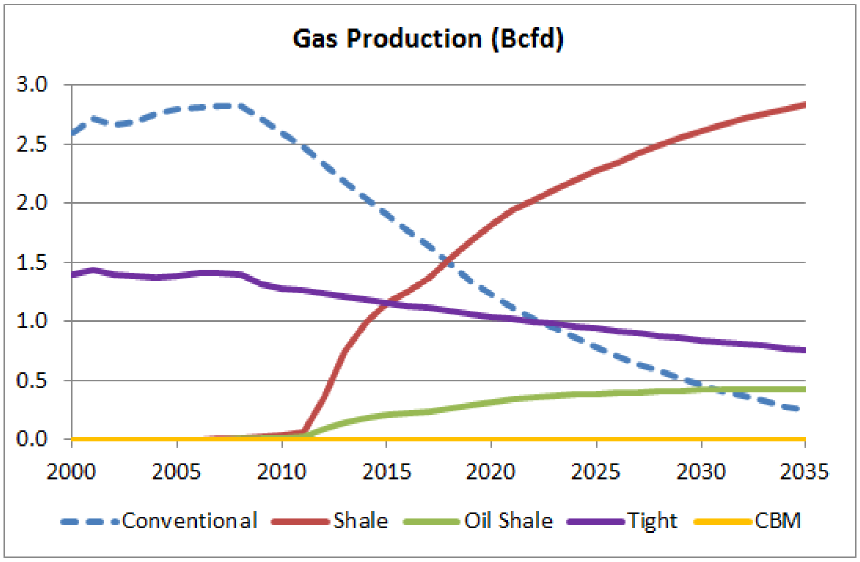
Source: ICF

Exhibit 41: Example Oil and Gas Well Decline Curves



Source: ICF

Exhibit 42: Example Breakout of Gas Production by Type



Source: ICF

NGL Transport Model (NGLTM)

ICF has developed a Natural Gas Liquids Transport Model (NGLTM) to represent the annual transport of NGLs in the U.S. and Canada. The model can move "raw mix" NGLs and "pure" NGLs products between supply areas and market areas along active corridors representing existing or future pipeline paths, as well as existing and future paths for rail movement of NGLs. Imports and exports of NGL products are also represented in the model framework.

NGL production is based on ICF's Detailed Production Report. Excess production is moved from growing supply areas to the dominant NGL demand centers along the Gulf coast. Imports and exports of pure NGL products bring the market areas into balance. NGLTM also includes estimates of ethane rejection due to growing production that outpaces demand and infrastructure growth.

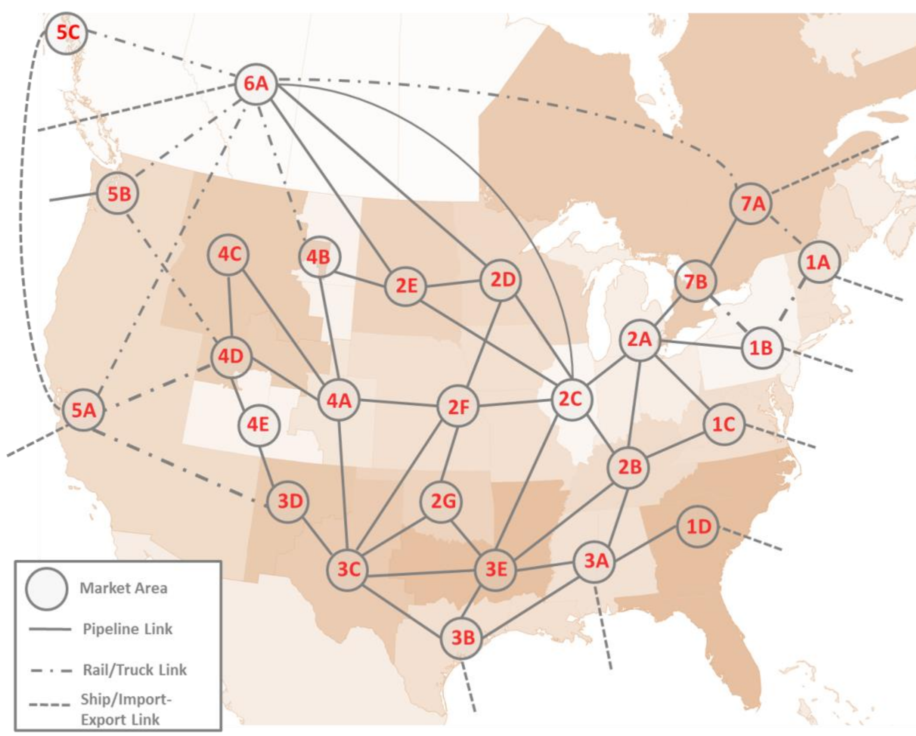
The NGLTM contains 27 supply/demand areas for the U.S. and Canada (**Exhibit 43**). The areas are connected by roughly 200 corridors representing individual pipeline projects and other forms of available transport (truck, rail, and ship) to move both raw NGLs (y-mix) and pure NGLs products like Ethane and Propane from production areas to demand areas.

- The model minimizes the cost of transport between areas using mileage-based transport costs with pipelines assumed to have significantly lower unit costs of transport than rail and truck transport.
- The model solves for annual NGL flows between areas. Raw mix and purity movements are accounted for separately.

- Capacity on individual NGL pipelines and pipeline expansion projects are often represented separately. Pipeline capacity for petroleum products pipelines that move NGLs, rich gas natural gas pipelines, or crude lines that transport raw mix or diluent products may also be represented in the model as NGLs transport capacity.
- Annual supply, demand, and imports/exports of NGLs are set by assumption or from other publicly available analyses using ICF's models and forecasting tools.
- Since the model is solving for annual transport, short term or seasonal storage of NGLs in raw or purity form is not considered.
- Capacity for transporting NGLs within each supply/demand area is not specifically modeled, but intra-area projects may be included to estimate total pipeline infrastructure costs.
- Refined petroleum products like gasoline or diesel fuel are not included in the movements of this model, but refined bi-products which resemble the heavier NGLs and can be used as diluents to Canadian oil sands crude are represented.

The model contains a historical stack of capacity currently available and planned for the future. Actual or announced costs of pipeline projects are included where available, and costs for expansions and new pipelines are estimated by ICF. Additional unplanned capacity that is required to balance production with demand is added based on ICF's judgment and knowledge of NGL markets.

Exhibit 43: NGLTM Paths



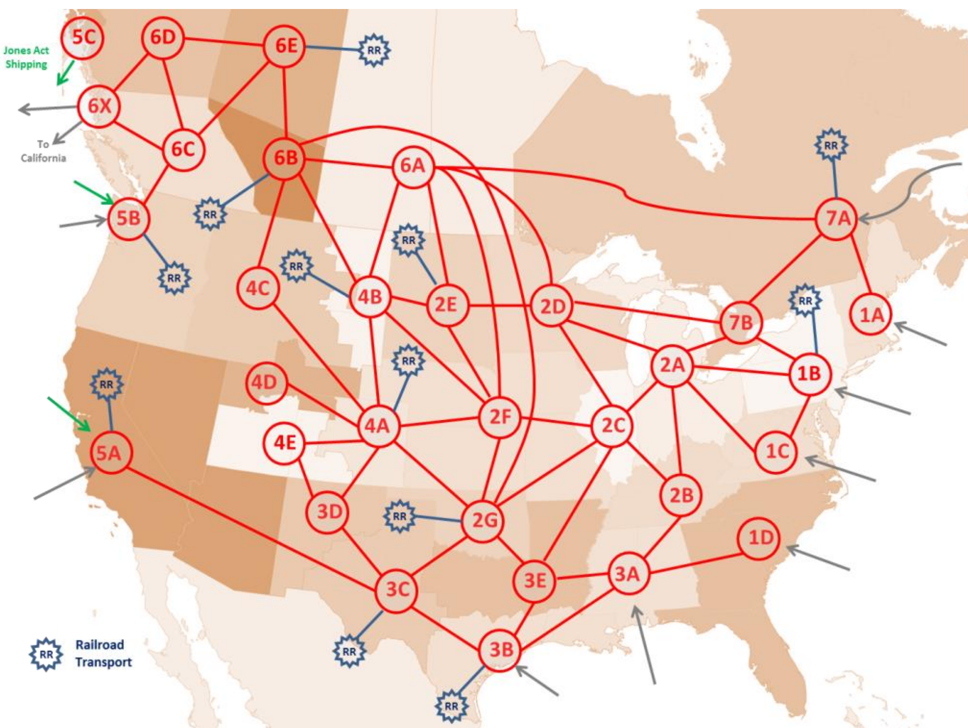
Source: ICF

Crude Oil Transport Model (COTM)

ICF has developed a Crude Oil Transport Model (COTM) to represent annual transport of crude oil in the U.S. and Canada. The model can move crude oil between supply areas and market areas along active corridors representing existing or future pipeline paths, as well as existing and future paths for rail movements of crude oil. Imports and exports of crude oil are also represented in the model framework.

The COTM contains 32 supply/demand areas for the U.S. and Canada (**Exhibit 44**). Crude oil production is based on ICF's Detailed Production Report. Excess production is moved from growing supply areas to the dominant oil demand centers (i.e., refineries) along the Gulf Coast. Imports and exports of crude oil bring the market areas into balance.

Exhibit 44: COTM Paths



Source: ICF

The supply and demand areas are connected by over 250 corridors representing individual pipeline projects and other forms of available transport (truck, rail, and ship) to move crude oil from production areas to demand areas.

- Refinery capacity is not assumed to grow. However, refineries may enhance their capacity to accommodate increased refinery input and changing crude slates over time.
- U.S. refinery input is based on EIA AEO projections. Canada refinery input is held constant at historical levels.

- Net imports into Canada can be negative, which means crude can be exported from the east and west coasts of Canada.

- Net imports to the U.S. Gulf Coast can fall to 0 MBPD.

- The model considers exports of crude (negative imports) from the U.S. Gulf Coast.

- Pipeline and railroad capacity along each corridor is specified as an input. Existing capacity is augmented by a stack of announced projects in the U.S. and Canada. Additional unplanned projects are added to permit markets to balance or facilitate export of oil.

- Rates for transport rely on each corridor's mileage and based on ICF's proprietary cost information. ICF assumes that rail corridor rates include additional costs for loading and unloading.

The model contains a historical stack of capacity currently available and planned for the future. Actual or announced costs of pipeline projects are included where available and costs for expansions and new pipelines are estimated by ICF. Additional unplanned capacity required to balance the production with demand is added based on ICF's judgment and knowledge of individual crude markets.

Appendix B: Details for New Infrastructure Development

Exhibit 45: U.S. and Canada

	Total 2013-2017	Total 2018-2035	Average 2013-2017	Average 2018-2035
Surface and Lease Equipment				
Gas Well Completions	42,353	144,061	8,471	8,003
Oil Well Completions	136,158	369,112	27,232	20,506
Total Well Completions	178,511	513,174	35,702	28,510
Gas Production (Bcfd)	443.3	2,116.3	88.7	117.6
Crude Oil Production (MMBbl/d)	63.42	315.91	12.68	17.55
NGL Production (MMBbl/d)	20.23	123.30	4.05	6.85
Offshore Platform Capacity (MBOE/d)	3,165	6,232	633	346
Gathering and Processing				
Gas Gathering Line Miles	33,675	88,340	6,735	4,908
Gas Gathering Line Diameter (Inch)	6.4	7.9	6.4	7.9
Gas Gathering Line Compressor (1000 HP)	4,435	8,540	887	474
Oil Gathering Line Miles	25,846	50,612	5,169	2,812
Oil Gathering Line Diameter (Inch)	4.6	5.5	4.6	5.5
Oil & Gas Gathering Line Miles	59,521	138,952	11,904	7,720
Oil & Gas Gathering Line Diameter (Inch)	5.6	7.0	5.6	7.0
Gas Processing Plant Capacity (Bcfd)	22.7	38.1	4.5	2.1
Gas Processing Plant Compressor (1000 HP)	2,267	3,812	453	212
NGL Fractionation Capacity (MBOE/d)	1,941	3,575	388	199
Oil, Gas, and NGL Pipelines				
Oil Line Miles	15,617	8,184	3,123	455
Oil Line Diameter (Inch)	22.0	28.9	22.0	28.9
Pump for Oil Lines (1000 HP)	2,964	1,016	593	56
NGL Line Miles	10,629	7,024	2,126	390
NGL Line Diameter (Inch)	14.9	17.5	14.9	17.5
Pump for NGL Lines (1000 HP)	390	293	78	16
Gas Line Miles	8,348	25,896	1,670	1,439
Gas Line Diameter (Inch)	24.6	28.9	24.6	28.9
Compressor for Gas Lines (1000 HP)	3,367	7,041	673	391
Oil, Gas, and NGL Line Miles	34,594	41,104	6,919	2,284
Oil, Gas, and NGL Line Diameter (Inch)	20.4	26.9	20.4	26.9
Oil and Gas Storage				
Crude Oil Storage Capaciy (MBbl)	170,532	139,411	34,106	7,745
Gas Storage Capacity (Bcf)	267	335	53	19
Refining and Oil Products Transport				
Refining Capacity Enhancement (1000 BPD)	0	0	0	0
Oil Product Pipeline Miles	2,526	2,981	505	166
Oil Product Pipeline Diameter (Inch)	11.5	13.5	11.5	13.5
Oil Product Pipeline Pump (1000 HP)	447	528	89	29
Crude Oil Rails Terminal Loading/Unloading Capacity (1000 BPD)	1,611	0	322	0
Export Terminals				
LNG Export Capacity (Bcfd)	2.4	12.9	0.5	0.7
NGL Export Capacity (MBOE/d)	813.5	1,511.7	162.7	84.0

Exhibit 46: Alaska

	Total 2013-2017	Total 2018-2035	Average 2013-2017	Average 2018-2035
Surface and Lease Equipment				
Gas Well Completions	18	51	4	3
Oil Well Completions	401	644	80	36
Total Well Completions	420	694	84	39
Gas Production (Bcfd)	4.6	15.1	0.9	0.8
Crude Oil Production (MMBbl/d)	2.32	6.46	0.46	0.36
NGL Production (MMBbl/d)	0.11	0.39	0.02	0.02
Offshore Platform Capacity (MBOE/d)	0	0	0	0
Gathering and Processing				
Gas Gathering Line Miles	46	77	9	4
Gas Gathering Line Diameter (Inch)	12.9	16.0	12.9	16.0
Gas Gathering Line Compressor (1000 HP)	1	2	0	0
Oil Gathering Line Miles	100	161	20	9
Oil Gathering Line Diameter (Inch)	8.0	8.0	8.0	8.0
Oil & Gas Gathering Line Miles	146	237	29	13
Oil & Gas Gathering Line Diameter (Inch)	9.5	10.6	9.5	10.6
Gas Processing Plant Capacity (Bcfd)	0.0	0.0	0.0	0.0
Gas Processing Plant Compressor (1000 HP)	2	1	0	0
NGL Fractionation Capacity (MBOE/d)	2	0	0	0
Oil, Gas, and NGL Pipelines				
Oil Line Miles	1	0	0	0
Oil Line Diameter (Inch)	0.0	18.0	0.0	18.0
Pump for Oil Lines (1000 HP)	0	0	0	0
NGL Line Miles	0	0	0	0
NGL Line Diameter (Inch)	0.0	0.0	0.0	0.0
Pump for NGL Lines (1000 HP)	0	0	0	0
Gas Line Miles	1	0	0	0
Gas Line Diameter (Inch)	30.0	30.0	30.0	30.0
Compressor for Gas Lines (1000 HP)	0	0	0	0
Oil, Gas, and NGL Line Miles	2	0	0	0
Oil, Gas, and NGL Line Diameter (Inch)	16.4	30.0	16.4	30.0
Oil and Gas Storage				
Crude Oil Storage Capaciy (MBbl)	277	0	55	0
Gas Storage Capacity (Bcf)	0	0	0	0
Refining and Oil Products Transport				
Refining Capacity Enhancement (1000 BPD)	0	0	0	0
Oil Product Pipeline Miles	9	6	2	0
Oil Product Pipeline Diameter (Inch)	8.8	9.4	8.8	9.4
Oil Product Pipeline Pump (1000 HP)	2	1	0	0
Crude Oil Rails Terminal Loading/Unloading Capacity (1000 BPD)	0	0	0	0
Export Terminals				
LNG Export Capacity (Bcfd)	0.0	0.0	0.0	0.0
NGL Export Capacity (MBOE/d)	0.0	0.0	0.0	0.0

Exhibit 47: Central

	Total 2013-2017	Total 2018-2035	Average 2013-2017	Average 2018-2035
Surface and Lease Equipment				
Gas Well Completions	5,475	10,932	1,095	607
Oil Well Completions	32,370	85,447	6,474	4,747
Total Well Completions	37,845	96,379	7,569	5,354
Gas Production (Bcfd)	75.8	275.7	15.2	15.3
Crude Oil Production (MMBbl/d)	9.44	46.92	1.89	2.61
NGL Production (MMBbl/d)	3.01	20.78	0.60	1.15
Offshore Platform Capacity (MBOE/d)	0	0	0	0
Gathering and Processing				
Gas Gathering Line Miles	6,833	16,776	1,367	932
Gas Gathering Line Diameter (Inch)	5.9	6.1	5.9	6.1
Gas Gathering Line Compressor (1000 HP)	337	840	67	47
Oil Gathering Line Miles	4,366	8,767	873	487
Oil Gathering Line Diameter (Inch)	5.4	6.4	5.4	6.4
Oil & Gas Gathering Line Miles	11,200	25,543	2,240	1,419
Oil & Gas Gathering Line Diameter (Inch)	5.7	6.2	5.7	6.2
Gas Processing Plant Capacity (Bcfd)	2.0	3.9	0.4	0.2
Gas Processing Plant Compressor (1000 HP)	197	385	39	21
NGL Fractionation Capacity (MBOE/d)	260	743	52	41
Oil, Gas, and NGL Pipelines				
Oil Line Miles	4,660	2,195	932	122
Oil Line Diameter (Inch)	19.3	29.3	19.3	29.3
Pump for Oil Lines (1000 HP)	540	149	108	8
NGL Line Miles	1,614	1,299	323	72
NGL Line Diameter (Inch)	12.9	18.5	12.9	18.5
Pump for NGL Lines (1000 HP)	90	58	18	3
Gas Line Miles	787	2,071	157	115
Gas Line Diameter (Inch)	15.5	21.5	15.5	21.5
Compressor for Gas Lines (1000 HP)	34	718	7	40
Oil, Gas, and NGL Line Miles	7,061	5,565	1,412	309
Oil, Gas, and NGL Line Diameter (Inch)	17.4	23.9	17.4	23.9
Oil and Gas Storage				
Crude Oil Storage Capaciy (MBbl)	40,470	14,902	8,094	828
Gas Storage Capacity (Bcf)	40	27	8	2
Refining and Oil Products Transport				
Refining Capacity Enhancement (1000 BPD)	0	0	0	0
Oil Product Pipeline Miles	919	545	184	30
Oil Product Pipeline Diameter (Inch)	9.9	9.9	9.9	9.9
Oil Product Pipeline Pump (1000 HP)	163	96	33	5
Crude Oil Rails Terminal Loading/Unloading Capacity (1000 BPD)	260	0	52	0
Export Terminals				
LNG Export Capacity (Bcfd)	0.0	0.0	0.0	0.0
NGL Export Capacity (MBOE/d)	0.0	0.0	0.0	0.0

Exhibit 48: Midwest

	Total 2013-2017	Total 2018-2035	Average 2013-2017	Average 2018-2035
Surface and Lease Equipment				
Gas Well Completions	121	157	24	9
Oil Well Completions	1,876	1,230	375	68
Total Well Completions	1,997	1,387	399	77
Gas Production (Bcfd)	1.6	3.8	0.3	0.2
Crude Oil Production (MMBbl/d)	0.19	0.26	0.04	0.01
NGL Production (MMBbl/d)	0.21	0.35	0.04	0.02
Offshore Platform Capacity (MBOE/d)	0	0	0	0
Gathering and Processing				
Gas Gathering Line Miles	407	278	81	15
Gas Gathering Line Diameter (Inch)	2.3	3.0	2.3	3.0
Gas Gathering Line Compressor (1000 HP)	10	12	2	1
Oil Gathering Line Miles	469	0	94	0
Oil Gathering Line Diameter (Inch)	2.0	0.0	2.0	0.0
Oil & Gas Gathering Line Miles	876	278	175	15
Oil & Gas Gathering Line Diameter (Inch)	2.1	3.0	2.1	3.0
Gas Processing Plant Capacity (Bcfd)	0.1	0.1	0.0	0.0
Gas Processing Plant Compressor (1000 HP)	6	7	1	0
NGL Fractionation Capacity (MBOE/d)	166	205	33	11
Oil, Gas, and NGL Pipelines				
Oil Line Miles	1,807	1	361	0
Oil Line Diameter (Inch)	25.7	18.0	25.7	18.0
Pump for Oil Lines (1000 HP)	762	0	152	0
NGL Line Miles	1,535	308	307	17
NGL Line Diameter (Inch)	12.3	11.5	12.3	11.5
Pump for NGL Lines (1000 HP)	74	53	15	3
Gas Line Miles	2,035	3,470	407	193
Gas Line Diameter (Inch)	25.6	30.2	25.6	30.2
Compressor for Gas Lines (1000 HP)	742	844	148	47
Oil, Gas, and NGL Line Miles	5,377	3,778	1,075	210
Oil, Gas, and NGL Line Diameter (Inch)	21.8	28.7	21.8	28.7
Oil and Gas Storage				
Crude Oil Storage Capaciy (MBbl)	1,203	151	241	8
Gas Storage Capacity (Bcf)	0	37	0	2
Refining and Oil Products Transport				
Refining Capacity Enhancement (1000 BPD)	0	0	0	0
Oil Product Pipeline Miles	746	487	149	27
Oil Product Pipeline Diameter (Inch)	11.3	11.0	11.3	11.0
Oil Product Pipeline Pump (1000 HP)	132	86	26	5
Crude Oil Rails Terminal Loading/Unloading Capacity (1000 BPD)	350	0	70	0
Export Terminals				
LNG Export Capacity (Bcfd)	0.0	0.0	0.0	0.0
NGL Export Capacity (MBOE/d)	0.0	0.0	0.0	0.0

Exhibit 49: Northeast

	Total 2013-2017	Total 2018-2035	Average 2013-2017	Average 2018-2035
Surface and Lease Equipment				
Gas Well Completions	9,699	54,481	1,940	3,027
Oil Well Completions	2,532	4,577	506	254
Total Well Completions	12,231	59,058	2,446	3,281
Gas Production (Bcfd)	94.3	735.3	18.9	40.9
Crude Oil Production (MMBbl/d)	0.45	2.28	0.09	0.13
NGL Production (MMBbl/d)	1.90	17.72	0.38	0.98
Offshore Platform Capacity (MBOE/d)	0	0	0	0
Gathering and Processing				
Gas Gathering Line Miles	2,503	9,816	501	545
Gas Gathering Line Diameter (Inch)	12.1	14.4	12.1	14.4
Gas Gathering Line Compressor (1000 HP)	2,319	3,581	464	199
Oil Gathering Line Miles	624	843	125	47
Oil Gathering Line Diameter (Inch)	4.0	4.3	4.0	4.3
Oil & Gas Gathering Line Miles	3,127	10,658	625	592
Oil & Gas Gathering Line Diameter (Inch)	10.5	13.6	10.5	13.6
Gas Processing Plant Capacity (Bcfd)	11.5	17.7	2.3	1.0
Gas Processing Plant Compressor (1000 HP)	1,154	1,771	231	98
NGL Fractionation Capacity (MBOE/d)	347	377	69	21
Oil, Gas, and NGL Pipelines				
Oil Line Miles	40	3	8	0
Oil Line Diameter (Inch)	18.0	18.0	18.0	18.0
Pump for Oil Lines (1000 HP)	0	0	0	0
NGL Line Miles	648	645	130	36
NGL Line Diameter (Inch)	13.0	13.3	13.0	13.3
Pump for NGL Lines (1000 HP)	6	20	1	1
Gas Line Miles	1,537	6,903	307	383
Gas Line Diameter (Inch)	26.4	29.4	26.4	29.4
Compressor for Gas Lines (1000 HP)	1,053	1,527	211	85
Oil, Gas, and NGL Line Miles	2,224	7,551	445	420
Oil, Gas, and NGL Line Diameter (Inch)	22.3	28.0	22.3	28.0
Oil and Gas Storage				
Crude Oil Storage Capaciy (MBbl)	7,474	598	1,495	33
Gas Storage Capacity (Bcf)	24	36	5	2
Refining and Oil Products Transport				
Refining Capacity Enhancement (1000 BPD)	0	0	0	0
Oil Product Pipeline Miles	80	57	16	3
Oil Product Pipeline Diameter (Inch)	14.7	16.0	14.7	16.0
Oil Product Pipeline Pump (1000 HP)	14	10	3	1
Crude Oil Rails Terminal Loading/Unloading Capacity (1000 BPD)	25	0	5	0
Export Terminals				
LNG Export Capacity (Bcfd)	0.0	0.7	0.0	0.0
NGL Export Capacity (MBOE/d)	146.1	244.5	29.2	13.6

Exhibit 50: Offshore

	Total 2013-2017	Total 2018-2035	Average 2013-2017	Average 2018-2035
Surface and Lease Equipment				
Gas Well Completions	132	472	26	26
Oil Well Completions	568	1,942	114	108
Total Well Completions	700	2,414	140	134
Gas Production (Bcfd)	17.5	43.7	3.5	2.4
Crude Oil Production (MMBbl/d)	0.00	0.00	0.00	0.00
NGL Production (MMBbl/d)	0.27	0.53	0.05	0.03
Offshore Platform Capacity (MBOE/d)	3,165	6,232	633	346
Gathering and Processing				
Gas Gathering Line Miles	93	279	19	15
Gas Gathering Line Diameter (Inch)	9.8	11.5	9.8	11.5
Gas Gathering Line Compressor (1000 HP)	1	4	0	0
Oil Gathering Line Miles	142	486	28	27
Oil Gathering Line Diameter (Inch)	5.3	7.3	5.3	7.3
Oil & Gas Gathering Line Miles	235	764	47	42
Oil & Gas Gathering Line Diameter (Inch)	7.1	8.8	7.1	8.8
Gas Processing Plant Capacity (Bcfd)	0.1	0.0	0.0	0.0
Gas Processing Plant Compressor (1000 HP)	12	5	2	0
NGL Fractionation Capacity (MBOE/d)	0	0	0	0
Oil, Gas, and NGL Pipelines				
Oil Line Miles	0	0	0	0
Oil Line Diameter (Inch)	0.0	0.0	0.0	0.0
Pump for Oil Lines (1000 HP)	0	0	0	0
NGL Line Miles	0	0	0	0
NGL Line Diameter (Inch)	0.0	0.0	0.0	0.0
Pump for NGL Lines (1000 HP)	0	0	0	0
Gas Line Miles	24	2	5	0
Gas Line Diameter (Inch)	30.0	30.0	30.0	30.0
Compressor for Gas Lines (1000 HP)	0	0	0	0
Oil, Gas, and NGL Line Miles	24	2	5	0
Oil, Gas, and NGL Line Diameter (Inch)	0.0	0.0	0.0	0.0
Oil and Gas Storage				
Crude Oil Storage Capaciy (MBbl)	0	0	0	0
Gas Storage Capacity (Bcf)	0	0	0	0
Refining and Oil Products Transport				
Refining Capacity Enhancement (1000 BPD)	0	0	0	0
Oil Product Pipeline Miles	0	0	0	0
Oil Product Pipeline Diameter (Inch)	0.0	0.0	0.0	0.0
Oil Product Pipeline Pump (1000 HP)	0	0	0	0
Crude Oil Rails Terminal Loading/Unloading Capacity (1000 BPD)	0	0	0	0
Export Terminals				
LNG Export Capacity (Bcfd)	0.0	0.0	0.0	0.0
NGL Export Capacity (MBOE/d)	0.0	0.0	0.0	0.0

Exhibit 51: Southeast

	Total 2013-2017	Total 2018-2035	Average 2013-2017	Average 2018-2035
Surface and Lease Equipment				
Gas Well Completions	446	1,164	89	65
Oil Well Completions	666	1,667	133	93
Total Well Completions	1,112	2,831	222	157
Gas Production (Bcfd)	2.7	5.2	0.5	0.3
Crude Oil Production (MMBbl/d)	0.52	1.10	0.10	0.06
NGL Production (MMBbl/d)	0.01	0.03	0.00	0.00
Offshore Platform Capacity (MBOE/d)	0	0	0	0
Gathering and Processing				
Gas Gathering Line Miles	227	503	45	28
Gas Gathering Line Diameter (Inch)	4.4	5.6	4.4	5.6
Gas Gathering Line Compressor (1000 HP)	1	4	0	0
Oil Gathering Line Miles	166	417	33	23
Oil Gathering Line Diameter (Inch)	5.3	4.0	5.3	4.0
Oil & Gas Gathering Line Miles	394	920	79	51
Oil & Gas Gathering Line Diameter (Inch)	4.8	4.9	4.8	4.9
Gas Processing Plant Capacity (Bcfd)	0.0	0.0	0.0	0.0
Gas Processing Plant Compressor (1000 HP)	1	1	0	0
NGL Fractionation Capacity (MBOE/d)	2	0	0	0
Oil, Gas, and NGL Pipelines				
Oil Line Miles	12	4	2	0
Oil Line Diameter (Inch)	18.0	18.0	18.0	18.0
Pump for Oil Lines (1000 HP)	0	0	0	0
NGL Line Miles	20	0	4	0
NGL Line Diameter (Inch)	8.0	0.0	8.0	0.0
Pump for NGL Lines (1000 HP)	0	0	0	0
Gas Line Miles	1,873	5,396	375	300
Gas Line Diameter (Inch)	22.8	29.6	22.8	29.6
Compressor for Gas Lines (1000 HP)	972	1,456	194	81
Oil, Gas, and NGL Line Miles	1,905	5,400	381	300
Oil, Gas, and NGL Line Diameter (Inch)	22.6	29.6	22.6	29.6
Oil and Gas Storage				
Crude Oil Storage Capaciy (MBbl)	2,343	795	469	44
Gas Storage Capacity (Bcf)	49	71	10	4
Refining and Oil Products Transport				
Refining Capacity Enhancement (1000 BPD)	0	0	0	0
Oil Product Pipeline Miles	107	284	21	16
Oil Product Pipeline Diameter (Inch)	20.6	22.9	20.6	22.9
Oil Product Pipeline Pump (1000 HP)	19	50	4	3
Crude Oil Rails Terminal Loading/Unloading Capacity (1000 BPD)	70	0	14	0
Export Terminals				
LNG Export Capacity (Bcfd)	0.0	10.7	0.0	0.6
NGL Export Capacity (MBOE/d)	0.0	0.0	0.0	0.0

Exhibit 52: Southwest

	Total 2013-2017	Total 2018-2035	Average 2013-2017	Average 2018-2035
Surface and Lease Equipment				
Gas Well Completions	18,096	49,043	3,619	2,725
Oil Well Completions	68,785	209,242	13,757	11,625
Total Well Completions	86,881	258,285	17,376	14,349
Gas Production (Bcfd)	162.3	708.8	32.5	39.4
Crude Oil Production (MMBbl/d)	28.00	161.49	5.60	8.97
NGL Production (MMBbl/d)	10.39	63.13	2.08	3.51
Offshore Platform Capacity (MBOE/d)	0	0	0	0
Gathering and Processing				
Gas Gathering Line Miles	16,708	44,508	3,342	2,473
Gas Gathering Line Diameter (Inch)	6.1	7.4	6.1	7.4
Gas Gathering Line Compressor (1000 HP)	1,201	3,023	240	168
Oil Gathering Line Miles	12,739	24,003	2,548	1,333
Oil Gathering Line Diameter (Inch)	4.8	6.1	4.8	6.1
Oil & Gas Gathering Line Miles	29,447	68,511	5,889	3,806
Oil & Gas Gathering Line Diameter (Inch)	5.5	7.0	5.5	7.0
Gas Processing Plant Capacity (Bcfd)	5.8	11.1	1.2	0.6
Gas Processing Plant Compressor (1000 HP)	584	1,114	117	62
NGL Fractionation Capacity (MBOE/d)	918	1,938	184	108
Oil, Gas, and NGL Pipelines				
Oil Line Miles	6,679	4,204	1,336	234
Oil Line Diameter (Inch)	19.1	26.7	19.1	26.7
Pump for Oil Lines (1000 HP)	730	647	146	36
NGL Line Miles	4,941	3,429	988	191
NGL Line Diameter (Inch)	17.3	19.8	17.3	19.8
Pump for NGL Lines (1000 HP)	175	113	35	6
Gas Line Miles	1,327	5,962	265	331
Gas Line Diameter (Inch)	27.0	30.8	27.0	30.8
Compressor for Gas Lines (1000 HP)	289	1,502	58	83
Oil, Gas, and NGL Line Miles	12,947	13,595	2,589	755
Oil, Gas, and NGL Line Diameter (Inch)	19.2	26.8	19.2	26.8
Oil and Gas Storage				
Crude Oil Storage Capaciy (MBbl)	85,257	96,318	17,051	5,351
Gas Storage Capacity (Bcf)	124	69	25	4
Refining and Oil Products Transport				
Refining Capacity Enhancement (1000 BPD)	0	0	0	0
Oil Product Pipeline Miles	407	1,263	81	70
Oil Product Pipeline Diameter (Inch)	13.6	14.2	13.6	14.2
Oil Product Pipeline Pump (1000 HP)	72	224	14	12
Crude Oil Rails Terminal Loading/Unloading Capacity (1000 BPD)	212	0	42	0
Export Terminals				
LNG Export Capacity (Bcfd)	2.4	1.2	0.5	0.1
NGL Export Capacity (MBOE/d)	665.1	1,143.8	133.0	63.5

Exhibit 53: Western

	Total 2013-2017	Total 2018-2035	Average 2013-2017	Average 2018-2035
Surface and Lease Equipment				
Gas Well Completions	79	319	16	18
Oil Well Completions	5,221	7,874	1,044	437
Total Well Completions	5,300	8,193	1,060	455
Gas Production (Bcfd)	2.9	8.9	0.6	0.5
Crude Oil Production (MMBbl/d)	2.82	5.26	0.56	0.29
NGL Production (MMBbl/d)	0.21	0.63	0.04	0.04
Offshore Platform Capacity (MBOE/d)	0	0	0	0
Gathering and Processing				
Gas Gathering Line Miles	982	1,293	196	72
Gas Gathering Line Diameter (Inch)	4.6	6.5	4.6	6.5
Gas Gathering Line Compressor (1000 HP)	11	25	2	1
Oil Gathering Line Miles	1,304	1,814	261	101
Oil Gathering Line Diameter (Inch)	4.1	4.0	4.1	4.0
Oil & Gas Gathering Line Miles	2,286	3,106	457	173
Oil & Gas Gathering Line Diameter (Inch)	4.3	5.1	4.3	5.1
Gas Processing Plant Capacity (Bcfd)	0.0	0.1	0.0	0.0
Gas Processing Plant Compressor (1000 HP)	4	10	1	1
NGL Fractionation Capacity (MBOE/d)	4	0	1	0
Oil, Gas, and NGL Pipelines				
Oil Line Miles	2	0	0	0
Oil Line Diameter (Inch)	0.0	18.0	0.0	18.0
Pump for Oil Lines (1000 HP)	0	0	0	0
NGL Line Miles	1	2	0	0
NGL Line Diameter (Inch)	14.0	14.0	14.0	14.0
Pump for NGL Lines (1000 HP)	0	0	0	0
Gas Line Miles	200	234	40	13
Gas Line Diameter (Inch)	25.2	23.3	25.2	23.3
Compressor for Gas Lines (1000 HP)	15	144	3	8
Oil, Gas, and NGL Line Miles	203	237	41	13
Oil, Gas, and NGL Line Diameter (Inch)	4.7	23.2	4.7	23.2
Oil and Gas Storage				
Crude Oil Storage Capaciy (MBbl)	333	0	67	0
Gas Storage Capacity (Bcf)	30	0	6	0
Refining and Oil Products Transport				
Refining Capacity Enhancement (1000 BPD)	0	0	0	0
Oil Product Pipeline Miles	259	339	52	19
Oil Product Pipeline Diameter (Inch)	10.4	11.8	10.4	11.8
Oil Product Pipeline Pump (1000 HP)	46	60	9	3
Crude Oil Rails Terminal Loading/Unloading Capacity (1000 BPD)	694	0	139	0
Export Terminals				
LNG Export Capacity (Bcfd)	0.0	0.0	0.0	0.0
NGL Export Capacity (MBOE/d)	2.2	5.1	0.4	0.3

Exhibit 54: Canada

	Total 2013-2017	Total 2018-2035	Average 2013-2017	Average 2018-2035
Surface and Lease Equipment				
Gas Well Completions	8,287	27,444	1,657	1,525
Oil Well Completions	23,738	56,489	4,748	3,138
Total Well Completions	32,025	83,933	6,405	4,663
Gas Production (Bcfd)	81.6	319.9	16.3	17.8
Crude Oil Production (MMBbl/d)	19.68	92.13	3.94	5.12
NGL Production (MMBbl/d)	4.12	19.74	0.82	1.10
Offshore Platform Capacity (MBOE/d)	0	0	0	0
Gathering and Processing				
Gas Gathering Line Miles	5,876	14,812	1,175	823
Gas Gathering Line Diameter (Inch)	6.1	7.1	6.1	7.1
Gas Gathering Line Compressor (1000 HP)	554	1,050	111	58
Oil Gathering Line Miles	5,935	14,122	1,187	785
Oil Gathering Line Diameter (Inch)	4.0	4.0	4.0	4.0
Oil & Gas Gathering Line Miles	11,811	28,934	2,362	1,607
Oil & Gas Gathering Line Diameter (Inch)	5.1	5.6	5.1	5.6
Gas Processing Plant Capacity (Bcfd)	3.0	5.2	0.6	0.3
Gas Processing Plant Compressor (1000 HP)	305	517	61	29
NGL Fractionation Capacity (MBOE/d)	243	311	49	17
Oil, Gas, and NGL Pipelines				
Oil Line Miles	2,415	1,777	483	99
Oil Line Diameter (Inch)	32.4	33.8	32.4	33.8
Pump for Oil Lines (1000 HP)	932	221	186	12
NGL Line Miles	1,870	1,340	374	74
NGL Line Diameter (Inch)	13.3	13.8	13.3	13.8
Pump for NGL Lines (1000 HP)	45	49	9	3
Gas Line Miles	565	1,858	113	103
Gas Line Diameter (Inch)	28.1	25.4	28.1	25.4
Compressor for Gas Lines (1000 HP)	261	849	52	47
Oil, Gas, and NGL Line Miles	4,850	4,975	970	276
Oil, Gas, and NGL Line Diameter (Inch)	24.5	25.3	24.5	25.3
Oil and Gas Storage				
Crude Oil Storage Capaciy (MBbl)	33,175	26,646	6,635	1,480
Gas Storage Capacity (Bcf)	0	95	0	5
Refining and Oil Products Transport				
Refining Capacity Enhancement (1000 BPD)	0	0	0	0
Oil Product Pipeline Miles	0	0	0	0
Oil Product Pipeline Diameter (Inch)	0.0	0.0	0.0	0.0
Oil Product Pipeline Pump (1000 HP)	0	0	0	0
Crude Oil Rails Terminal Loading/Unloading Capacity (1000 BPD)	0	0	0	0
Export Terminals				
LNG Export Capacity (Bcfd)	0.0	0.3	0.0	0.0
NGL Export Capacity (MBOE/d)	0.0	118.3	0.0	6.6

Exhibit 55: United States

	Total 2013-2017	Total 2018-2035	Average 2013-2017	Average 2018-2035
Surface and Lease Equipment				
Gas Well Completions	34,065	116,617	6,813	6,479
Oil Well Completions	112,420	312,623	22,484	17,368
Total Well Completions	146,485	429,241	29,297	23,847
Gas Production (Bcfd)	361.6	1,796.5	72.3	99.8
Crude Oil Production (MMBbl/d)	43.74	223.78	8.75	12.43
NGL Production (MMBbl/d)	16.11	103.56	3.22	5.75
Offshore Platform Capacity (MBOE/d)	3,165	6,232	633	346
Gathering and Processing				
Gas Gathering Line Miles	27,799	73,528	5,560	4,085
Gas Gathering Line Diameter (Inch)	6.5	8.0	6.5	8.0
Gas Gathering Line Compressor (1000 HP)	3,881	7,491	776	416
Oil Gathering Line Miles	19,911	36,490	3,982	2,027
Oil Gathering Line Diameter (Inch)	4.8	6.1	4.8	6.1
Oil & Gas Gathering Line Miles	47,710	110,018	9,542	6,112
Oil & Gas Gathering Line Diameter (Inch)	5.8	7.4	5.8	7.4
Gas Processing Plant Capacity (Bcfd)	19.6	32.9	3.9	1.8
Gas Processing Plant Compressor (1000 HP)	1,962	3,294	392	183
NGL Fractionation Capacity (MBOE/d)	1,698	3,263	340	181
Oil, Gas, and NGL Pipelines				
Oil Line Miles	13,202	6,407	2,640	356
Oil Line Diameter (Inch)	20.0	27.6	20.0	27.6
Pump for Oil Lines (1000 HP)	2,032	795	406	44
NGL Line Miles	8,759	5,684	1,752	316
NGL Line Diameter (Inch)	15.2	18.3	15.2	18.3
Pump for NGL Lines (1000 HP)	346	244	69	14
Gas Line Miles	7,783	24,038	1,557	1,335
Gas Line Diameter (Inch)	24.3	29.2	24.3	29.2
Compressor for Gas Lines (1000 HP)	3,106	6,191	621	344
Oil, Gas, and NGL Line Miles	29,743	36,129	5,949	2,007
Oil, Gas, and NGL Line Diameter (Inch)	19.7	27.2	19.7	27.2
Oil and Gas Storage				
Crude Oil Storage Capaciy (MBbl)	137,357	112,765	27,471	6,265
Gas Storage Capacity (Bcf)	267	240	53	13
Refining and Oil Products Transport				
Refining Capacity Enhancement (1000 BPD)	0	0	0	0
Oil Product Pipeline Miles	2,526	2,981	505	166
Oil Product Pipeline Diameter (Inch)	11.5	13.5	11.5	13.5
Oil Product Pipeline Pump (1000 HP)	447	528	89	29
Crude Oil Rails Terminal Loading/Unloading Capacity (1000 BPD)	1,611	0	322	0
Export Terminals				
LNG Export Capacity (Bcfd)	2.4	12.6	0.5	0.7
NGL Export Capacity (MBOE/d)	813.5	1,393.3	162.7	77.4

Appendix C: Regional Capital Expenditures for Infrastructure Development

Exhibit 56: Total Capital Expenditure (Constant Unit Cost), Millions of 2016$

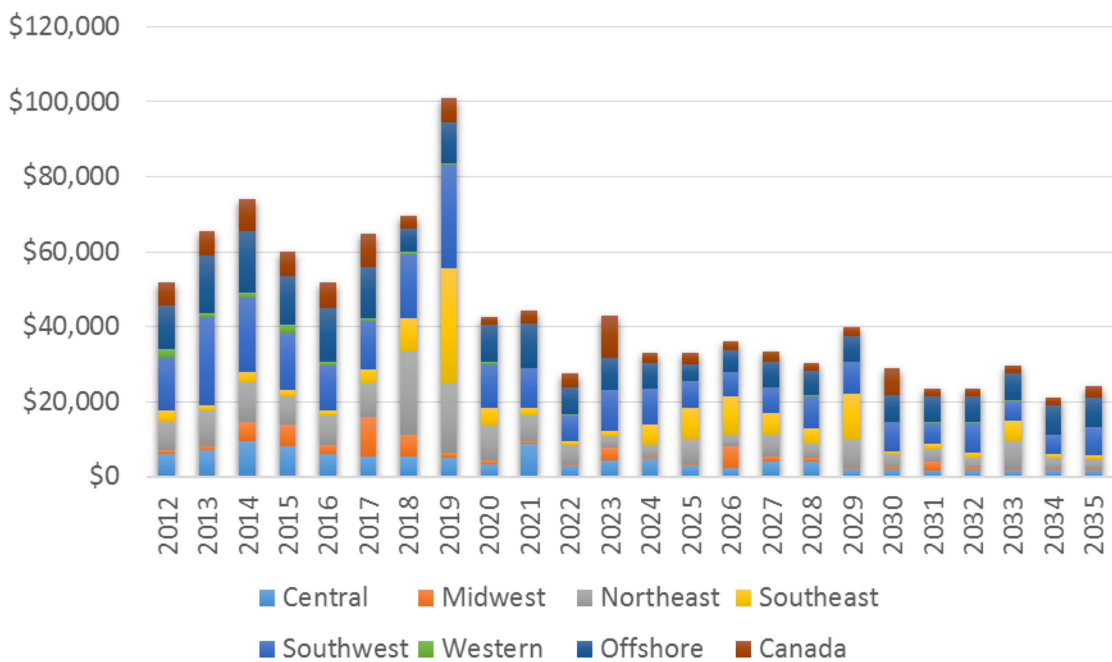


Exhibit 57: Total Capital Expenditures (Escalating Unit Cost Case), Millions of 2016$

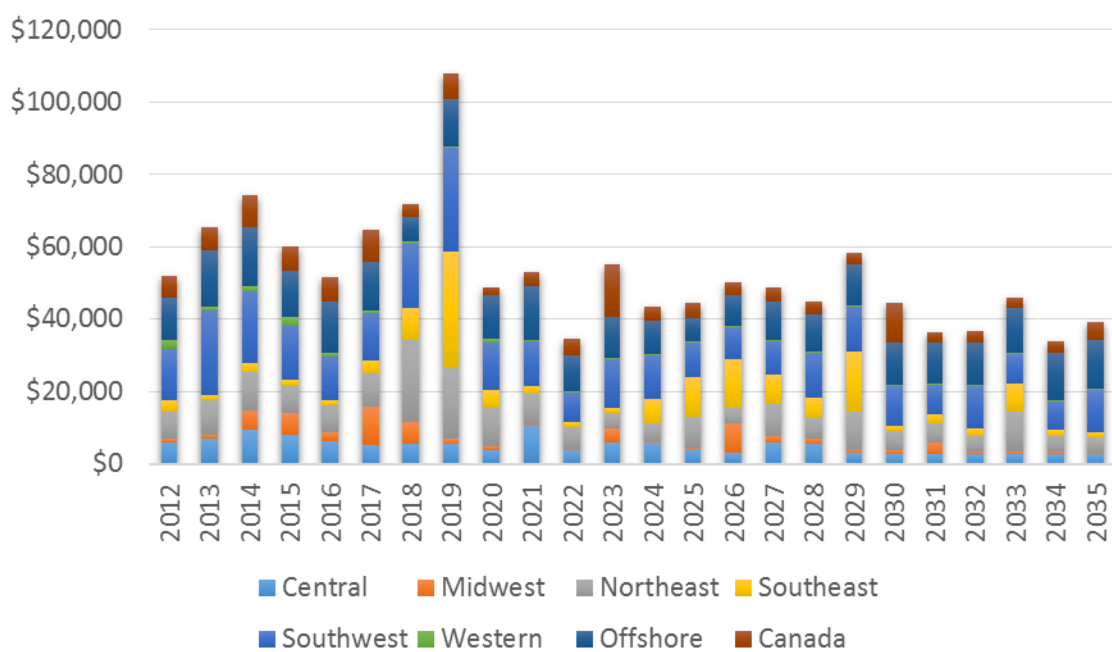


Exhibit 58: Total Capital Expenditure (Constant Unit Cost Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	Southwest	Western	Offshore	Alaska	Canada	US
2012	$6,040	$881	$7,567	$3,183	$14,049	$2,413	$11,610	$65	$6,054	$45,809
2013	$7,035	$1,041	$9,559	$1,237	$23,554	$1,057	$15,662	$67	$6,282	$59,211
2014	$9,336	$5,257	$10,698	$2,527	$19,795	$1,574	$16,224	$64	$8,709	$65,475
2015	$8,048	$5,862	$7,599	$1,701	$14,946	$2,337	$12,981	$50	$6,580	$53,523
2016	$6,207	$2,362	$7,682	$1,347	$12,178	$803	$14,419	$24	$6,699	$45,021
2017	$5,298	$10,480	$9,067	$3,700	$12,941	$901	$13,553	$23	$8,835	$55,963
2018	$5,233	$6,072	$22,135	$8,746	$17,043	$734	$6,150	$25	$3,541	$66,138
2019	$5,126	$1,337	$18,416	$30,849	$27,415	$315	$11,070	$20	$6,574	$94,548
2020	$3,248	$1,088	$9,292	$4,644	$11,564	$799	$9,922	$18	$1,886	$40,575
2021	$8,864	$435	$6,931	$2,143	$10,432	$255	$11,780	$18	$3,413	$40,857
2022	$3,085	$347	$4,848	$1,168	$6,777	$256	$7,492	$17	$3,670	$23,989
2023	$4,399	$3,199	$3,356	$1,178	$10,916	$185	$8,361	$16	$11,328	$31,611
2024	$4,515	$356	$3,681	$5,423	$9,415	$190	$6,560	$17	$2,883	$30,157
2025	$2,820	$473	$6,413	$8,578	$7,075	$259	$4,434	$17	$3,058	$30,069
2026	$2,125	$6,129	$2,925	$10,340	$6,265	$220	$5,641	$17	$2,480	$33,663
2027	$4,041	$1,309	$5,873	$5,839	$6,615	$220	$6,773	$16	$2,653	$30,686
2028	$3,905	$993	$3,792	$4,214	$8,548	$217	$6,546	$17	$2,204	$28,233
2029	$1,942	$417	$7,438	$12,174	$8,502	$216	$6,917	$17	$2,132	$37,623
2030	$1,795	$729	$3,463	$857	$7,602	$211	$7,143	$17	$7,090	$21,817
2031	$1,724	$2,417	$3,159	$1,642	$5,361	$240	$6,903	$17	$1,976	$21,462
2032	$1,676	$635	$2,735	$1,431	$7,717	$243	$7,000	$18	$1,930	$21,454
2033	$1,696	$378	$7,422	$5,417	$5,076	$242	$7,363	$18	$1,957	$27,613
2034	$1,652	$429	$2,835	$1,028	$5,127	$241	$7,631	$18	$2,011	$18,962
2035	$1,612	$413	$2,606	$962	$7,527	$240	$7,733	$18	$3,203	$21,112
Total 2013-2017	**$35,923**	**$25,002**	**$44,605**	**$10,512**	**$83,414**	**$6,671**	**$72,838**	**$227**	**$37,104**	**$279,192**
Total 2018-2035	**$59,460**	**$27,155**	**$117,321**	**$106,632**	**$168,976**	**$5,283**	**$135,420**	**$320**	**$63,988**	**$620,567**
Average 2012-2017	**$6,994**	**$4,314**	**$8,695**	**$2,282**	**$16,244**	**$1,514**	**$14,075**	**$49**	**$7,193**	**$54,167**
Average 2018-2035	**$3,303**	**$1,509**	**$6,518**	**$5,924**	**$9,388**	**$294**	**$7,523**	**$18**	**$3,555**	**$34,476**

Exhibit 59: Total Capital Expenditures (Escalating Unit Cost Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	Southwest	Western	Offshore	Alaska	Canada	US
2012	$6,040	$881	$7,567	$3,183	$14,049	$2,413	$11,610	$65	$6,054	$45,809
2013	$7,035	$1,041	$9,559	$1,237	$23,554	$1,057	$15,662	$74	$6,282	$59,218
2014	$9,336	$5,257	$10,698	$2,527	$19,795	$1,574	$16,224	$64	$8,709	$65,475
2015	$8,048	$5,862	$7,599	$1,701	$14,946	$2,337	$12,981	$50	$6,580	$53,523
2016	$6,207	$2,362	$7,682	$1,347	$12,178	$803	$14,419	$28	$6,699	$45,026
2017	$5,298	$10,480	$9,067	$3,700	$12,941	$901	$13,553	$23	$8,835	$55,963
2018	$5,486	$6,141	$22,605	$8,811	$17,604	$774	$6,870	$26	$3,630	$68,316
2019	$5,574	$1,408	$19,600	$32,025	$28,918	$349	$12,920	$21	$7,032	$100,816
2020	$3,749	$1,196	$10,549	$5,035	$13,016	$907	$12,077	$20	$2,146	$46,548
2021	$10,434	$497	$8,237	$2,414	$12,173	$310	$14,928	$21	$4,016	$49,014
2022	$3,844	$409	$5,942	$1,381	$8,278	$324	$9,869	$21	$4,444	$30,068
2023	$5,860	$3,812	$4,242	$1,439	$13,563	$242	$11,432	$21	$14,526	$40,611
2024	$5,928	$447	$4,823	$6,665	$12,178	$258	$9,299	$23	$3,817	$39,619
2025	$3,933	$606	$8,414	$11,034	$9,538	$356	$6,506	$24	$4,162	$40,410
2026	$3,090	$8,042	$4,134	$13,570	$8,795	$316	$8,561	$24	$3,512	$46,531
2027	$5,898	$1,886	$8,582	$8,126	$9,515	$325	$10,560	$23	$3,860	$44,915
2028	$5,694	$1,375	$5,616	$5,727	$12,303	$326	$10,417	$26	$3,271	$41,484
2029	$3,023	$573	$10,711	$16,834	$12,363	$329	$11,136	$25	$3,198	$54,994
2030	$2,804	$1,032	$5,259	$1,228	$11,272	$326	$11,681	$26	$10,749	$33,627
2031	$2,695	$3,310	$5,011	$2,517	$8,147	$369	$11,393	$27	$3,036	$33,469
2032	$2,653	$904	$4,268	$2,107	$11,588	$377	$11,698	$27	$3,004	$33,622
2033	$2,727	$536	$11,094	$7,975	$7,877	$379	$12,398	$28	$3,071	$43,015
2034	$2,661	$614	$4,522	$1,520	$8,038	$381	$13,000	$28	$3,191	$30,764
2035	$2,612	$594	$4,175	$1,431	$11,594	$383	$13,284	$28	$5,089	$34,101
Total 2013-2017	**$35,923**	**$25,002**	**$44,605**	**$10,512**	**$83,414**	**$6,671**	**$72,838**	**$239**	**$37,104**	**$279,204**
Total 2018-2035	**$78,666**	**$33,382**	**$147,781**	**$129,839**	**$216,760**	**$7,030**	**$198,027**	**$439**	**$85,754**	**$811,924**
Average 2013-2017	**$7,185**	**$5,000**	**$8,921**	**$2,102**	**$16,683**	**$1,334**	**$14,568**	**$48**	**$7,421**	**$55,841**
Average 2018-2035	**$4,370**	**$1,855**	**$8,210**	**$7,213**	**$12,042**	**$391**	**$11,001**	**$24**	**$4,764**	**$45,107**

Exhibit 60: Surface and Lease Equipment (Constant Unit Cost Case), Millions of 2016$

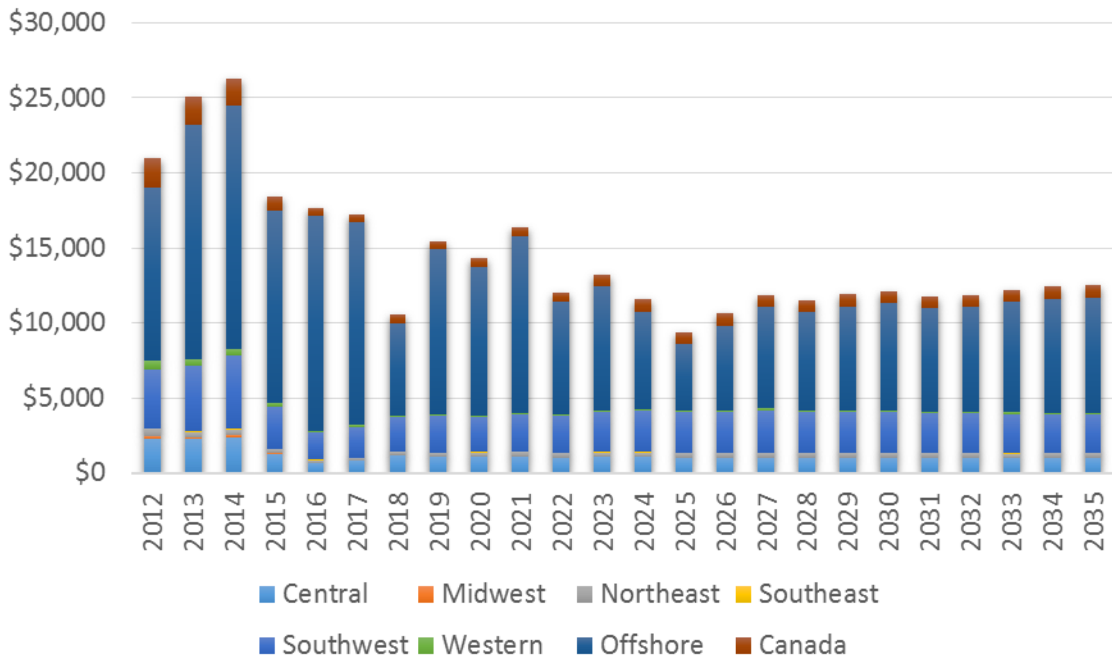


Exhibit 61: Surface and Lease Equipment (Escalating Unit Cost Case), Millions of 2016$

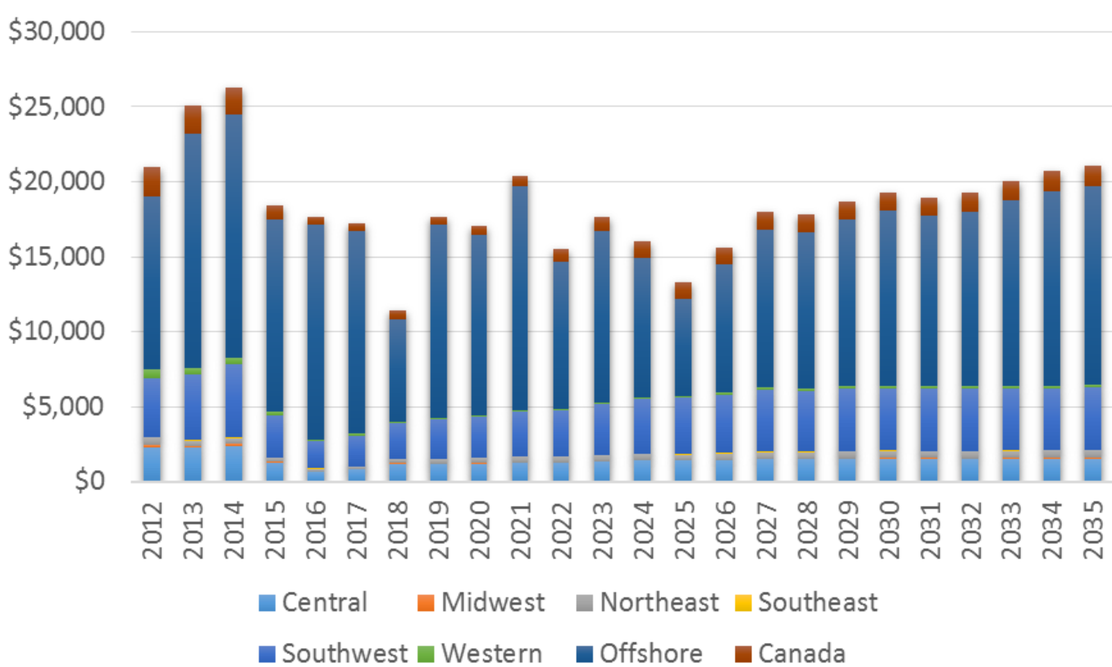


Exhibit 62: Surface and Lease Equipment (Constant Unit Cost Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	Southwest	Western	Offshore	Alaska	Canada	US
2012	$2,283	$147	$517	$39	$3,879	$641	$11,525	$27	$1,983	$19,058
2013	$2,241	$127	$339	$51	$4,429	$411	$15,589	$27	$1,875	$23,214
2014	$2,397	$135	$387	$55	$4,876	$441	$16,157	$29	$1,792	$24,475
2015	$1,229	$68	$288	$29	$2,827	$220	$12,799	$14	$941	$17,473
2016	$660	$32	$167	$16	$1,831	$102	$14,370	$7	$470	$17,185
2017	$796	$34	$185	$16	$2,055	$110	$13,526	$7	$499	$16,729
2018	$1,155	$8	$279	$24	$2,253	$103	$6,134	$7	$567	$9,964
2019	$1,053	$11	$287	$27	$2,405	$89	$11,042	$7	$504	$14,921
2020	$1,052	$12	$309	$21	$2,373	$82	$9,898	$7	$569	$13,755
2021	$1,047	$11	$336	$22	$2,522	$83	$11,754	$7	$610	$15,782
2022	$1,014	$8	$313	$19	$2,485	$89	$7,475	$7	$639	$11,409
2023	$1,059	$9	$309	$23	$2,633	$95	$8,341	$7	$766	$12,477
2024	$1,049	$12	$311	$24	$2,734	$103	$6,544	$7	$845	$10,783
2025	$1,017	$10	$281	$22	$2,717	$107	$4,421	$7	$805	$8,584
2026	$1,014	$11	$296	$22	$2,739	$105	$5,627	$7	$807	$9,821
2027	$1,021	$16	$311	$24	$2,822	$107	$6,756	$7	$827	$11,063
2028	$1,001	$13	$305	$22	$2,722	$105	$6,529	$8	$797	$10,706
2029	$1,004	$17	$306	$23	$2,745	$105	$6,900	$7	$794	$11,107
2030	$1,004	$16	$309	$23	$2,723	$103	$7,126	$7	$808	$11,311
2031	$986	$18	$303	$22	$2,668	$104	$6,886	$8	$796	$10,994
2032	$972	$18	$306	$21	$2,628	$107	$6,983	$8	$799	$11,044
2033	$967	$20	$307	$21	$2,610	$108	$7,345	$8	$809	$11,387
2034	$964	$21	$313	$21	$2,588	$108	$7,612	$8	$825	$11,635
2035	$962	$23	$312	$21	$2,565	$108	$7,714	$8	$840	$11,712
Total 2013-2017	**$7,323**	**$396**	**$1,366**	**$167**	**$16,017**	**$1,283**	**$72,441**	**$84**	**$5,579**	**$99,077**
Total 2018-2035	**$18,343**	**$255**	**$5,493**	**$401**	**$46,933**	**$1,812**	**$135,086**	**$131**	**$13,409**	**$208,454**
Average 2012-2017	**$1,601**	**$90**	**$314**	**$34**	**$3,316**	**$321**	**$13,994**	**$18**	**$1,260**	**$19,689**
Average 2018-2035	**$1,019**	**$14**	**$305**	**$22**	**$2,607**	**$101**	**$7,505**	**$7**	**$745**	**$11,581**

Exhibit 63: Surface and Lease Equipment (Escalating Unit Cost Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	Southwest	Western	Offshore	Alaska	Canada	US
2012	$2,283	$147	$517	$39	$3,879	$641	$11,525	$27	$1,983	$19,058
2013	$2,241	$127	$339	$51	$4,429	$411	$15,589	$27	$1,875	$23,214
2014	$2,397	$135	$387	$55	$4,876	$441	$16,157	$29	$1,792	$24,475
2015	$1,229	$68	$288	$29	$2,827	$220	$12,799	$14	$941	$17,473
2016	$660	$32	$167	$16	$1,831	$102	$14,370	$7	$470	$17,185
2017	$796	$34	$185	$16	$2,055	$110	$13,526	$7	$499	$16,729
2018	$1,209	$8	$292	$25	$2,359	$108	$6,853	$8	$594	$10,862
2019	$1,152	$12	$314	$29	$2,630	$98	$12,889	$8	$551	$17,132
2020	$1,200	$14	$353	$24	$2,708	$93	$12,050	$8	$649	$16,450
2021	$1,244	$13	$399	$26	$2,996	$99	$14,897	$8	$724	$19,682
2022	$1,252	$10	$386	$23	$3,068	$110	$9,848	$8	$789	$14,705
2023	$1,357	$12	$397	$29	$3,375	$122	$11,407	$9	$982	$16,707
2024	$1,393	$16	$413	$31	$3,632	$137	$9,276	$10	$1,123	$14,908
2025	$1,399	$14	$387	$30	$3,737	$147	$6,489	$10	$1,108	$12,214
2026	$1,442	$16	$421	$31	$3,896	$149	$8,540	$10	$1,148	$14,504
2027	$1,492	$23	$455	$35	$4,123	$156	$10,534	$10	$1,209	$16,828
2028	$1,493	$20	$455	$33	$4,060	$157	$10,393	$11	$1,189	$16,622
2029	$1,516	$25	$461	$34	$4,143	$159	$11,110	$11	$1,198	$17,459
2030	$1,539	$25	$473	$34	$4,173	$158	$11,654	$11	$1,238	$18,068
2031	$1,526	$27	$469	$33	$4,127	$161	$11,367	$12	$1,232	$17,721
2032	$1,523	$29	$479	$33	$4,116	$168	$11,671	$12	$1,251	$18,032
2033	$1,527	$32	$485	$33	$4,118	$170	$12,370	$12	$1,277	$18,748
2034	$1,539	$34	$499	$34	$4,133	$173	$12,971	$12	$1,317	$19,394
2035	$1,548	$36	$503	$34	$4,129	$174	$13,254	$12	$1,352	$19,691
Total 2013-2017	**$7,323**	**$396**	**$1,366**	**$167**	**$16,017**	**$1,283**	**$72,441**	**$84**	**$5,579**	**$99,077**
Total 2018-2035	**$25,351**	**$366**	**$7,640**	**$555**	**$65,522**	**$2,538**	**$197,573**	**$183**	**$18,931**	**$299,727**
Average 2013-2017	**$1,465**	**$79**	**$273**	**$33**	**$3,203**	**$257**	**$14,488**	**$17**	**$1,116**	**$19,815**
Average 2018-2035	**$1,408**	**$20**	**$424**	**$31**	**$3,640**	**$141**	**$10,976**	**$10**	**$1,052**	**$16,652**

Exhibit 64: Gathering and Processing (Constant Unit Cost Case), Millions of 2016$

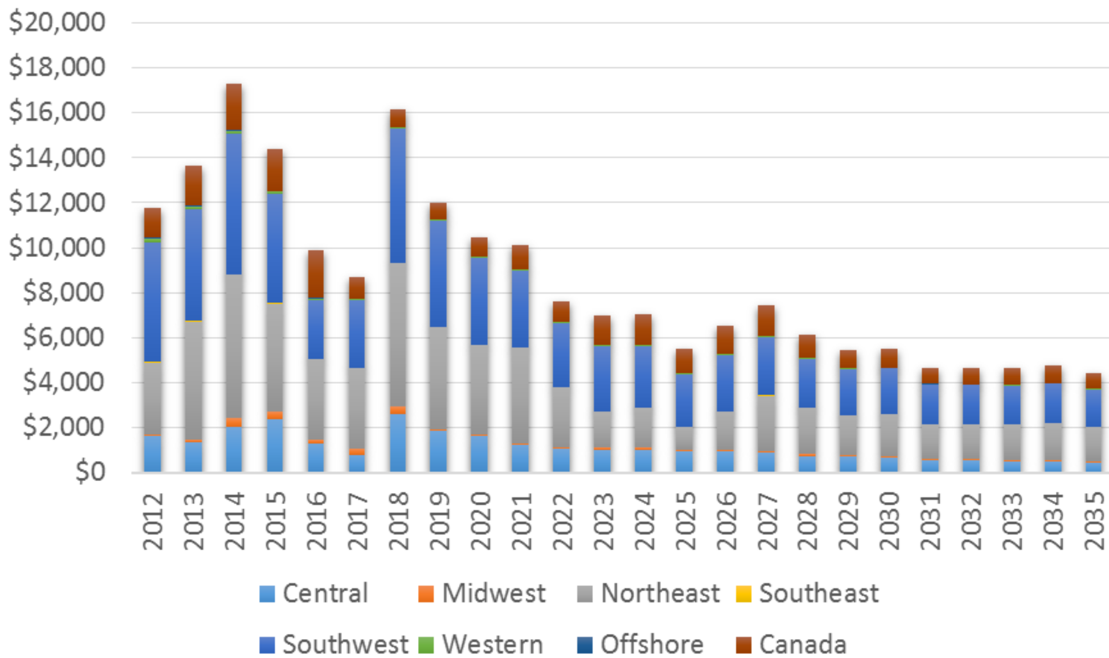


Exhibit 65: Gathering and Processing (Escalating Unit Cost Case), Millions of 2016$

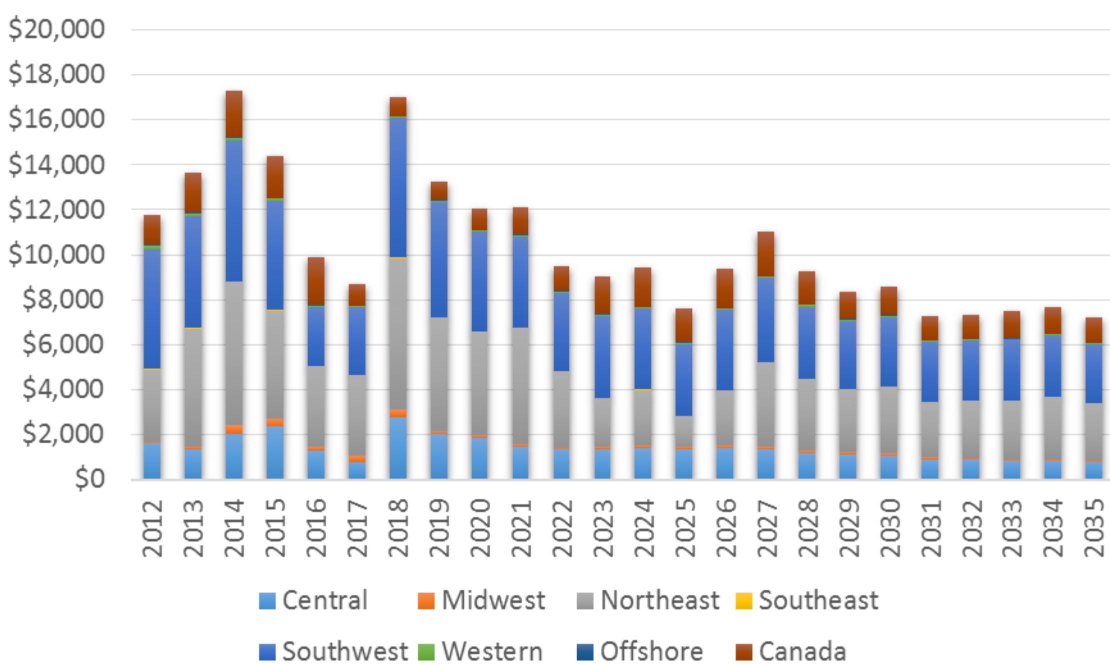


Exhibit 66: Gathering and Processing (Constant Unit Cost Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	Southwest	Western	Offshore	Alaska	Canada	US
2012	$1,622	$52	$3,209	$25	$5,304	$165	$77	$37	$1,323	$10,490
2013	$1,352	$106	$5,253	$27	$4,974	$130	$64	$39	$1,718	$11,944
2014	$2,021	$432	$6,347	$27	$6,229	$141	$63	$30	$2,048	$15,290
2015	$2,393	$323	$4,808	$23	$4,839	$95	$49	$21	$1,881	$12,552
2016	$1,296	$141	$3,620	$18	$2,590	$57	$43	$16	$2,096	$7,780
2017	$796	$264	$3,603	$8	$2,992	$44	$24	$11	$973	$7,742
2018	$2,622	$321	$6,393	$10	$5,948	$47	$14	$11	$814	$15,365
2019	$1,837	$77	$4,565	$11	$4,716	$46	$27	$10	$741	$11,288
2020	$1,608	$65	$3,990	$9	$3,893	$40	$22	$10	$833	$9,636
2021	$1,208	$95	$4,238	$9	$3,426	$47	$25	$9	$1,049	$9,058
2022	$1,036	$78	$2,695	$7	$2,847	$44	$16	$9	$907	$6,732
2023	$1,025	$90	$1,619	$9	$2,894	$43	$19	$9	$1,309	$5,707
2024	$1,011	$100	$1,789	$9	$2,732	$42	$16	$9	$1,334	$5,707
2025	$941	$61	$1,005	$8	$2,341	$40	$12	$9	$1,113	$4,418
2026	$940	$79	$1,668	$8	$2,535	$39	$14	$9	$1,256	$5,292
2027	$867	$84	$2,467	$9	$2,586	$38	$17	$9	$1,377	$6,077
2028	$742	$70	$2,060	$8	$2,180	$36	$16	$9	$1,012	$5,122
2029	$697	$67	$1,786	$8	$2,039	$36	$17	$9	$814	$4,659
2030	$664	$60	$1,861	$8	$2,035	$34	$18	$9	$844	$4,688
2031	$565	$47	$1,521	$8	$1,763	$31	$17	$9	$700	$3,961
2032	$532	$48	$1,568	$8	$1,726	$30	$17	$9	$694	$3,939
2033	$506	$43	$1,580	$8	$1,741	$30	$18	$10	$749	$3,935
2034	$489	$45	$1,666	$8	$1,737	$28	$19	$10	$757	$4,001
2035	$459	$41	$1,531	$8	$1,646	$28	$19	$9	$705	$3,741
Total 2013-2017	**$7,857**	**$1,267**	**$23,630**	**$102**	**$21,624**	**$467**	**$243**	**$117**	**$8,717**	**$55,307**
Total 2018-2035	**$17,747**	**$1,470**	**$44,003**	**$151**	**$48,784**	**$679**	**$322**	**$170**	**$17,009**	**$113,326**
Average 2012-2017	**$1,580**	**$220**	**$4,473**	**$21**	**$4,488**	**$105**	**$53**	**$26**	**$1,673**	**$10,966**
Average 2018-2035	**$986**	**$82**	**$2,445**	**$8**	**$2,710**	**$38**	**$18**	**$9**	**$945**	**$6,296**

Exhibit 67: Gathering and Processing (Escalating Unit Cost Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	t	Western	Offshore	Alaska	Canada	US
2012	$1,622	$52	$3,209	$25	$5,304	$165	$77	$37	$1,323	$10,490
2013	$1,352	$106	$5,253	$27	$4,974	$130	$64	$39	$1,718	$11,944
2014	$2,021	$432	$6,347	$27	$6,229	$141	$63	$30	$2,048	$15,290
2015	$2,393	$323	$4,808	$23	$4,839	$95	$49	$21	$1,881	$12,552
2016	$1,296	$141	$3,620	$18	$2,590	$57	$43	$16	$2,096	$7,780
2017	$796	$264	$3,603	$8	$2,992	$44	$24	$11	$973	$7,742
2018	$2,777	$336	$6,746	$11	$6,213	$50	$14	$12	$852	$16,159
2019	$2,049	$84	$5,063	$12	$5,138	$52	$29	$11	$810	$12,438
2020	$1,884	$74	$4,637	$10	$4,417	$47	$25	$11	$950	$11,104
2021	$1,483	$113	$5,153	$11	$4,041	$58	$30	$11	$1,245	$10,899
2022	$1,327	$96	$3,394	$9	$3,487	$57	$20	$11	$1,118	$8,401
2023	$1,370	$115	$2,122	$11	$3,674	$58	$25	$11	$1,675	$7,386
2024	$1,408	$132	$2,444	$12	$3,591	$58	$21	$12	$1,769	$7,679
2025	$1,360	$84	$1,400	$11	$3,183	$59	$16	$13	$1,526	$6,125
2026	$1,409	$111	$2,453	$11	$3,559	$58	$20	$13	$1,781	$7,636
2027	$1,337	$123	$3,762	$13	$3,726	$59	$25	$13	$2,007	$9,057
2028	$1,168	$104	$3,207	$12	$3,205	$57	$24	$14	$1,502	$7,791
2029	$1,110	$100	$2,807	$12	$3,032	$57	$26	$14	$1,225	$7,158
2030	$1,073	$91	$2,976	$12	$3,071	$54	$27	$14	$1,289	$7,319
2031	$918	$73	$2,444	$12	$2,686	$49	$26	$14	$1,078	$6,222
2032	$876	$75	$2,557	$12	$2,662	$49	$26	$15	$1,081	$6,272
2033	$838	$67	$2,598	$12	$2,705	$48	$28	$15	$1,177	$6,311
2034	$821	$72	$2,780	$12	$2,729	$47	$29	$15	$1,204	$6,504
2035	$773	$66	$2,556	$12	$2,608	$46	$30	$15	$1,129	$6,106
Total 2013-2017	**$7,857**	**$1,267**	**$23,630**	**$102**	**$21,624**	**$467**	**$243**	**$117**	**$8,717**	**$55,307**
Total 2018-2035	**$23,981**	**$1,916**	**$59,100**	**$207**	**$63,727**	**$964**	**$440**	**$233**	**$23,418**	**$150,567**
Average 2013-2017	**$1,571**	**$253**	**$4,726**	**$20**	**$4,325**	**$93**	**$49**	**$23**	**$1,743**	**$11,061**
Average 2018-2035	**$1,332**	**$106**	**$3,283**	**$11**	**$3,540**	**$54**	**$24**	**$13**	**$1,301**	**$8,365**

Exhibit 68: Oil, Gas, and NGL Pipelines (Constant Unit Cost Case), Millions of 2016$

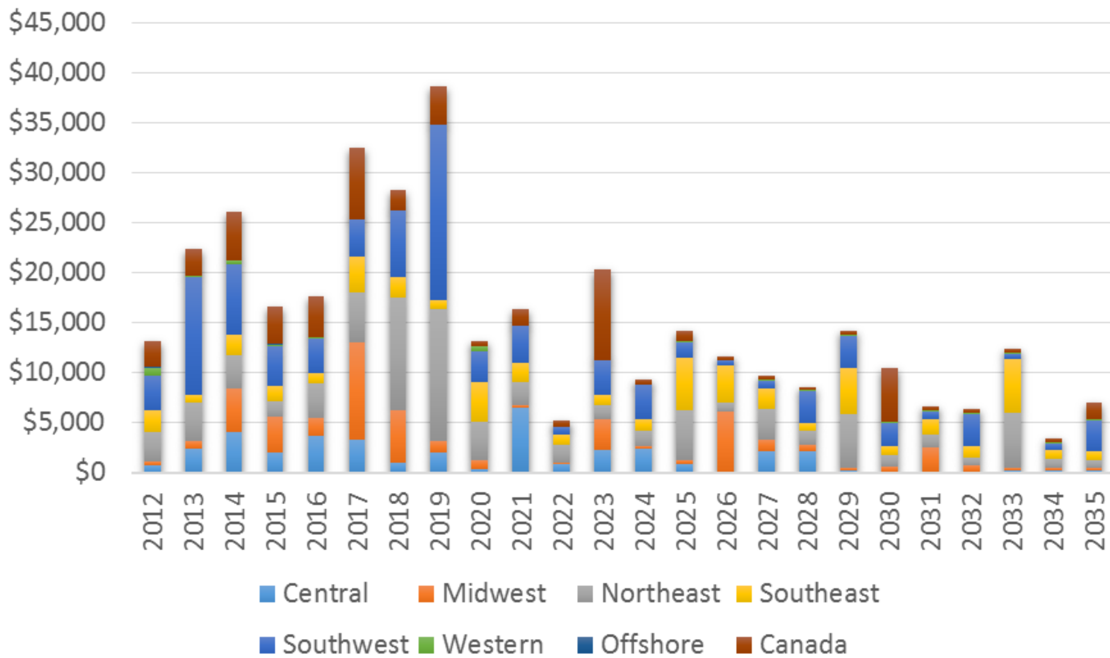


Exhibit 69: Oil, Gas, and NGL Pipelines (Escalating Unit Cost Case), Millions of 2016$

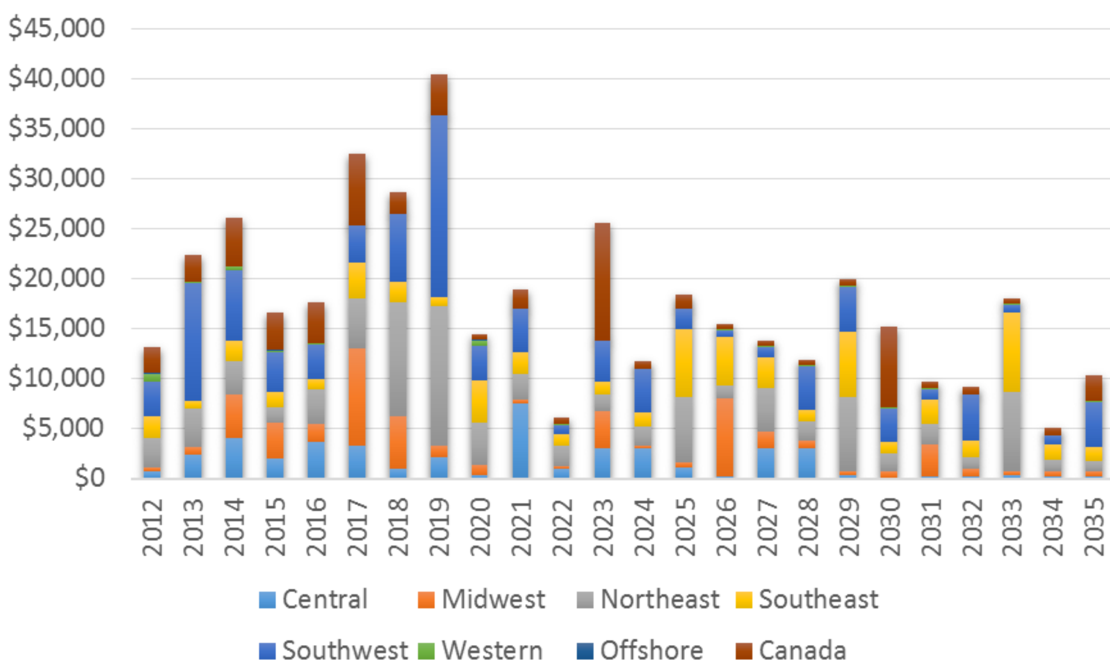


Exhibit 70: Oil, Gas, and NGL Pipelines (Constant Unit Cost Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	Southwest	Western	Offshore	Alaska	Canada	US
2012	$670	$429	$2,947	$2,236	$3,424	$818	$8	$1	$2,566	$10,533
2013	$2,333	$783	$3,835	$880	$11,766	$60	$9	$2	$2,682	$19,668
2014	$4,004	$4,351	$3,410	$2,084	$7,031	$345	$4	$1	$4,807	$21,230
2015	$1,975	$3,646	$1,549	$1,554	$3,956	$106	$133	$1	$3,698	$12,919
2016	$3,713	$1,736	$3,472	$1,019	$3,408	$236	$6	$1	$4,074	$13,590
2017	$3,253	$9,786	$4,984	$3,611	$3,694	$7	$3	$1	$7,097	$25,340
2018	$949	$5,282	$11,245	$2,067	$6,685	$9	$2	$1	$2,064	$26,239
2019	$2,039	$1,123	$13,237	$851	$17,534	$10	$2	$0	$3,910	$34,797
2020	$346	$911	$3,813	$3,966	$3,093	$537	$1	$0	$472	$12,666
2021	$6,502	$236	$2,276	$2,013	$3,717	$11	$1	$0	$1,631	$14,755
2022	$832	$169	$1,759	$1,045	$763	$9	$1	$0	$603	$4,577
2023	$2,268	$3,070	$1,364	$1,115	$3,386	$8	$1	$0	$9,125	$11,211
2024	$2,412	$214	$1,517	$1,159	$3,475	$7	$1	$0	$572	$8,785
2025	$828	$371	$5,063	$5,184	$1,589	$73	$0	$0	$1,010	$13,109
2026	$139	$6,009	$914	$3,612	$563	$39	$0	$0	$383	$11,277
2027	$2,121	$1,178	$3,049	$2,106	$759	$38	$0	$0	$421	$9,251
2028	$2,130	$652	$1,380	$819	$3,210	$38	$0	$0	$374	$8,229
2029	$209	$304	$5,299	$4,611	$3,282	$37	$0	$0	$490	$13,744
2030	$96	$470	$1,247	$795	$2,406	$37	$0	$0	$5,411	$5,052
2031	$142	$2,322	$1,322	$1,581	$738	$69	$0	$0	$467	$6,175
2032	$142	$538	$849	$1,147	$3,177	$69	$0	$0	$431	$5,921
2033	$193	$285	$5,522	$5,356	$540	$68	$0	$0	$396	$11,964
2034	$170	$333	$844	$968	$617	$68	$0	$0	$424	$3,001
2035	$163	$319	$751	$902	$3,136	$68	$0	$0	$1,646	$5,339
Total 2013-2017	**$15,278**	**$20,302**	**$17,250**	**$9,148**	**$29,855**	**$754**	**$155**	**$5**	**$22,358**	**$92,748**
Total 2018-2035	**$21,680**	**$23,787**	**$61,448**	**$39,297**	**$58,669**	**$1,194**	**$11**	**$3**	**$29,830**	**$206,090**
Average 2012-2017	**$2,658**	**$3,455**	**$3,366**	**$1,897**	**$5,547**	**$262**	**$27**	**$1**	**$4,154**	**$17,213**
Average 2018-2035	**$1,204**	**$1,322**	**$3,414**	**$2,183**	**$3,259**	**$66**	**$1**	**$0**	**$1,657**	**$11,449**

Exhibit 71: Oil, Gas, and NGL Pipelines (Escalating Unit Cost Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	Southwest	Western	Offshore	Alaska	Canada	US
2012	$670	$429	$2,947	$2,236	$3,424	$818	$8	$1	$2,566	$10,533
2013	$2,333	$783	$3,835	$880	$11,766	$60	$9	$5	$2,682	$19,671
2014	$4,004	$4,351	$3,410	$2,084	$7,031	$345	$4	$1	$4,807	$21,230
2015	$1,975	$3,646	$1,549	$1,554	$3,956	$106	$133	$1	$3,698	$12,919
2016	$3,713	$1,736	$3,472	$1,019	$3,408	$236	$6	$5	$4,074	$13,594
2017	$3,253	$9,786	$4,984	$3,611	$3,694	$7	$3	$1	$7,097	$25,340
2018	$965	$5,320	$11,330	$2,113	$6,789	$10	$2	$1	$2,085	$26,529
2019	$2,157	$1,179	$13,866	$918	$18,227	$11	$2	$0	$4,120	$36,359
2020	$388	$998	$4,214	$4,265	$3,391	$603	$2	$0	$534	$13,860
2021	$7,578	$265	$2,590	$2,265	$4,243	$13	$1	$0	$1,900	$16,956
2022	$1,011	$195	$2,062	$1,234	$898	$11	$1	$0	$738	$5,414
2023	$3,070	$3,649	$1,641	$1,360	$4,105	$11	$1	$0	$11,704	$13,837
2024	$3,068	$262	$1,880	$1,457	$4,336	$9	$1	$0	$751	$11,013
2025	$1,126	$469	$6,540	$6,762	$2,038	$95	$1	$0	$1,351	$17,031
2026	$191	$7,876	$1,193	$4,861	$742	$52	$1	$0	$536	$14,916
2027	$3,020	$1,700	$4,297	$3,133	$1,025	$52	$0	$0	$605	$13,228
2028	$2,984	$868	$1,884	$1,144	$4,400	$53	$0	$0	$547	$11,334
2029	$349	$407	$7,372	$6,531	$4,545	$53	$0	$0	$725	$19,257
2030	$142	$639	$1,739	$1,137	$3,372	$52	$0	$0	$8,179	$7,081
2031	$203	$3,168	$2,080	$2,427	$1,051	$99	$0	$0	$708	$9,028
2032	$204	$758	$1,213	$1,667	$4,532	$99	$0	$0	$661	$8,473
2033	$312	$395	$7,993	$7,884	$775	$99	$0	$0	$611	$17,458
2034	$251	$466	$1,224	$1,429	$895	$99	$0	$0	$663	$4,365
2035	$241	$449	$1,097	$1,339	$4,581	$100	$0	$0	$2,589	$7,806
Total 2013-2017	**$15,278**	**$20,302**	**$17,250**	**$9,148**	**$29,855**	**$754**	**$155**	**$12**	**$22,358**	**$92,755**
Total 2018-2035	**$27,260**	**$29,065**	**$74,213**	**$51,926**	**$69,943**	**$1,520**	**$14**	**$3**	**$39,007**	**$253,944**
Average 2013-2017	**$3,056**	**$4,060**	**$3,450**	**$1,830**	**$5,971**	**$151**	**$31**	**$2**	**$4,472**	**$18,551**
Average 2018-2035	**$1,514**	**$1,615**	**$4,123**	**$2,885**	**$3,886**	**$84**	**$1**	**$0**	**$2,167**	**$14,108**

Exhibit 72: Oil and Gas Storage (Constant Unit Cost Case), Millions of 2016$

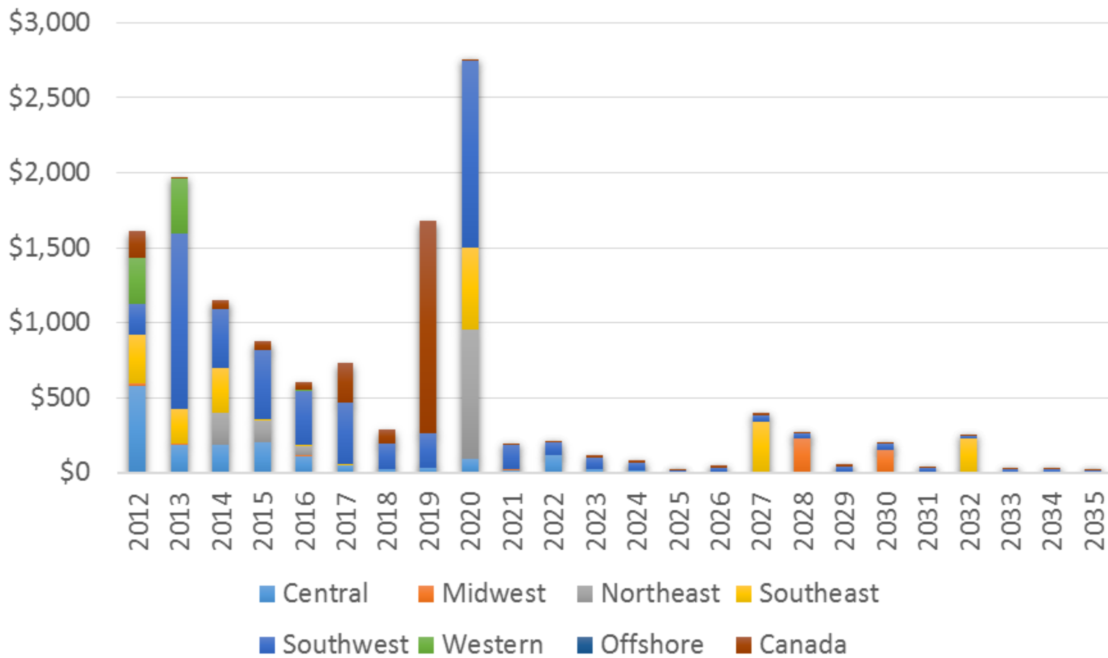


Exhibit 73: Oil and Gas Storage (Escalating Unit Cost Case), Millions of 2016$

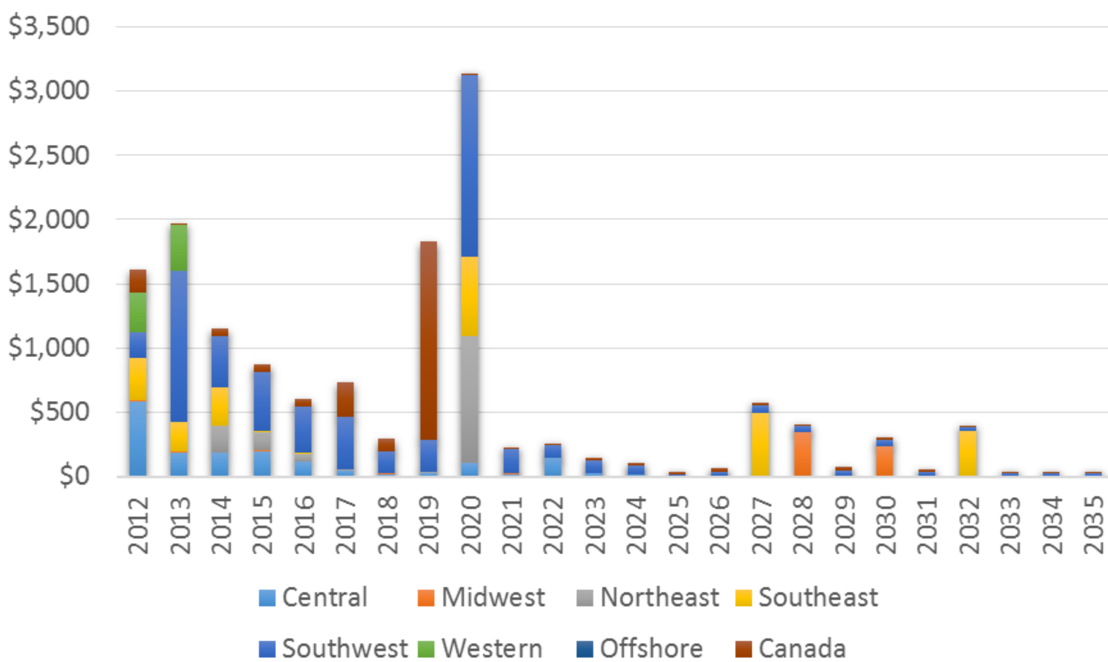


Exhibit 74: Oil and Gas Storage (Base Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	Southwest	Western	Offshore	Alaska	Canada	US
2012	$581	$13	$5	$325	$197	$310	$0	$0	$182	$1,430
2013	$189	$3	$4	$226	$1,175	$363	$0	$0	$5	$1,960
2014	$185	$2	$211	$298	$393	$0	$0	$0	$61	$1,089
2015	$198	$7	$142	$6	$459	$0	$0	$0	$59	$814
2016	$112	$4	$58	$13	$359	$3	$0	$0	$59	$549
2017	$48	$1	$3	$3	$411	$0	$0	$0	$266	$467
2018	$21	$1	$2	$2	$168	$0	$0	$0	$94	$192
2019	$28	$1	$2	$2	$229	$0	$0	$0	$1,419	$262
2020	$94	$0	$861	$549	$1,243	$0	$0	$0	$12	$2,747
2021	$18	$0	$1	$1	$167	$0	$0	$0	$7	$188
2022	$116	$0	$1	$1	$83	$0	$0	$0	$9	$201
2023	$19	$0	$1	$1	$82	$0	$0	$0	$13	$103
2024	$15	$0	$1	$0	$53	$0	$0	$0	$15	$70
2025	$5	$0	$0	$0	$7	$0	$0	$0	$13	$12
2026	$4	$0	$0	$0	$26	$0	$0	$0	$18	$30
2027	$4	$0	$0	$336	$45	$0	$0	$0	$12	$385
2028	$3	$228	$0	$0	$34	$0	$0	$0	$7	$266
2029	$3	$0	$0	$0	$33	$0	$0	$0	$19	$36
2030	$2	$152	$0	$0	$36	$0	$0	$0	$13	$190
2031	$2	$0	$0	$0	$26	$0	$0	$0	$10	$28
2032	$1	$0	$0	$224	$20	$0	$0	$0	$5	$246
2033	$1	$0	$0	$0	$20	$0	$0	$0	$2	$21
2034	$1	$0	$0	$0	$19	$0	$0	$0	$3	$20
2035	$1	$0	$0	$0	$14	$0	$0	$0	$10	$15
Total 2013-2017	**$733**	**$18**	**$418**	**$546**	**$2,798**	**$366**	**$0**	**$0**	**$451**	**$4,878**
Total 2018-2035	**$338**	**$383**	**$869**	**$1,117**	**$2,305**	**$0**	**$0**	**$0**	**$1,683**	**$5,012**
Average 2012-2017	**$219**	**$5**	**$71**	**$145**	**$499**	**$113**	**$0**	**$0**	**$105**	**$1,051**
Average 2018-2035	**$19**	**$21**	**$48**	**$62**	**$128**	**$0**	**$0**	**$0**	**$93**	**$278**

Exhibit 75: Oil and Gas Storage (Escalating Unit Cost Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	Southwest	Western	Offshore	Alaska	Canada	US
2012	$581	$13	$5	$325	$197	$310	$0	$0	$182	$1,430
2013	$189	$3	$4	$226	$1,175	$363	$0	$3	$5	$1,962
2014	$185	$2	$211	$298	$393	$0	$0	$0	$61	$1,089
2015	$198	$7	$142	$6	$459	$0	$0	$0	$59	$814
2016	$112	$4	$58	$13	$359	$3	$0	$2	$59	$550
2017	$48	$1	$3	$3	$411	$0	$0	$0	$266	$467
2018	$21	$1	$2	$2	$174	$0	$0	$0	$99	$200
2019	$31	$1	$2	$2	$247	$0	$0	$0	$1,551	$282
2020	$107	$0	$982	$625	$1,412	$0	$0	$0	$13	$3,126
2021	$21	$0	$1	$1	$192	$0	$0	$0	$9	$217
2022	$142	$0	$1	$1	$99	$0	$0	$0	$11	$244
2023	$24	$0	$2	$1	$100	$0	$0	$0	$16	$126
2024	$20	$0	$1	$0	$67	$0	$0	$0	$19	$88
2025	$7	$0	$0	$0	$9	$0	$0	$0	$18	$16
2026	$5	$0	$0	$0	$35	$0	$0	$0	$25	$40
2027	$5	$0	$0	$489	$62	$0	$0	$0	$17	$556
2028	$4	$343	$0	$0	$48	$0	$0	$0	$11	$395
2029	$4	$0	$0	$0	$47	$0	$0	$0	$28	$51
2030	$4	$235	$0	$0	$50	$0	$0	$0	$20	$289
2031	$2	$0	$0	$0	$37	$0	$0	$0	$16	$40
2032	$2	$0	$0	$349	$29	$0	$0	$0	$8	$381
2033	$2	$0	$0	$0	$29	$0	$0	$0	$3	$31
2034	$2	$0	$0	$0	$27	$0	$0	$0	$5	$29
2035	$1	$0	$0	$0	$21	$0	$0	$0	$17	$22
Total 2013-2017	**$733**	**$18**	**$418**	**$546**	**$2,798**	**$366**	**$0**	**$4**	**$451**	**$4,883**
Total 2018-2035	**$404**	**$580**	**$991**	**$1,473**	**$2,686**	**$0**	**$0**	**$0**	**$1,886**	**$6,133**
Average 2013-2017	**$147**	**$4**	**$84**	**$109**	**$560**	**$73**	**$0**	**$1**	**$90**	**$977**
Average 2018-2035	**$22**	**$32**	**$55**	**$82**	**$149**	**$0**	**$0**	**$0**	**$105**	**$341**

Exhibit 76: Refining and Oil Products Transport (Constant Unit Cost Case), Millions of 2016$

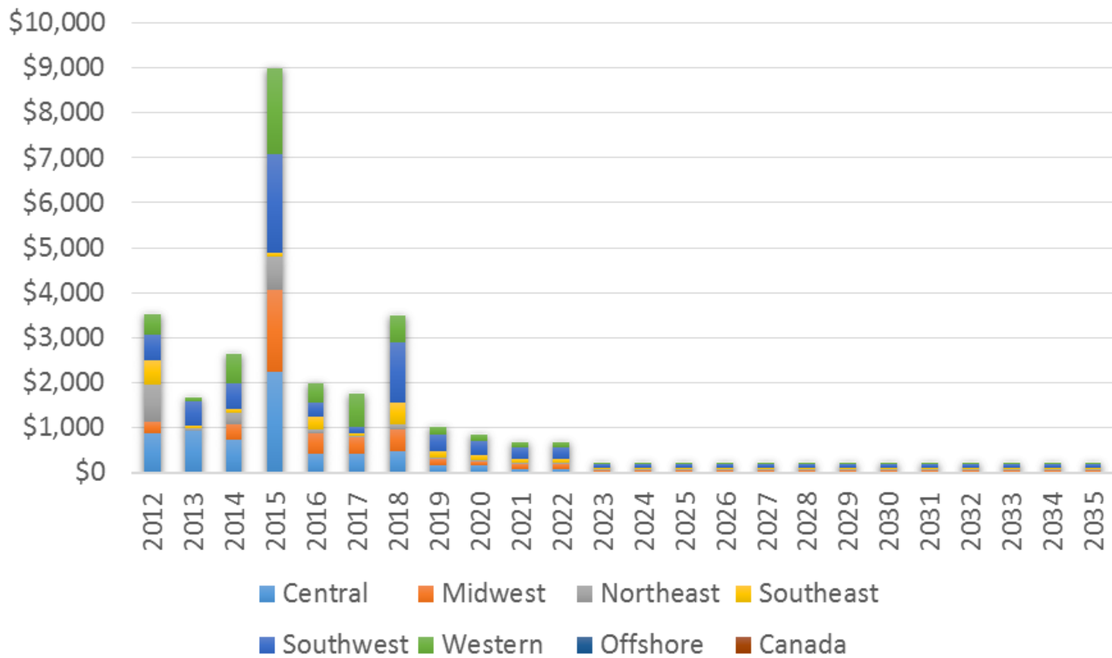


Exhibit 77: Refining and Oil Products Transport (Escalating Unit Cost Case), Millions of 2016$

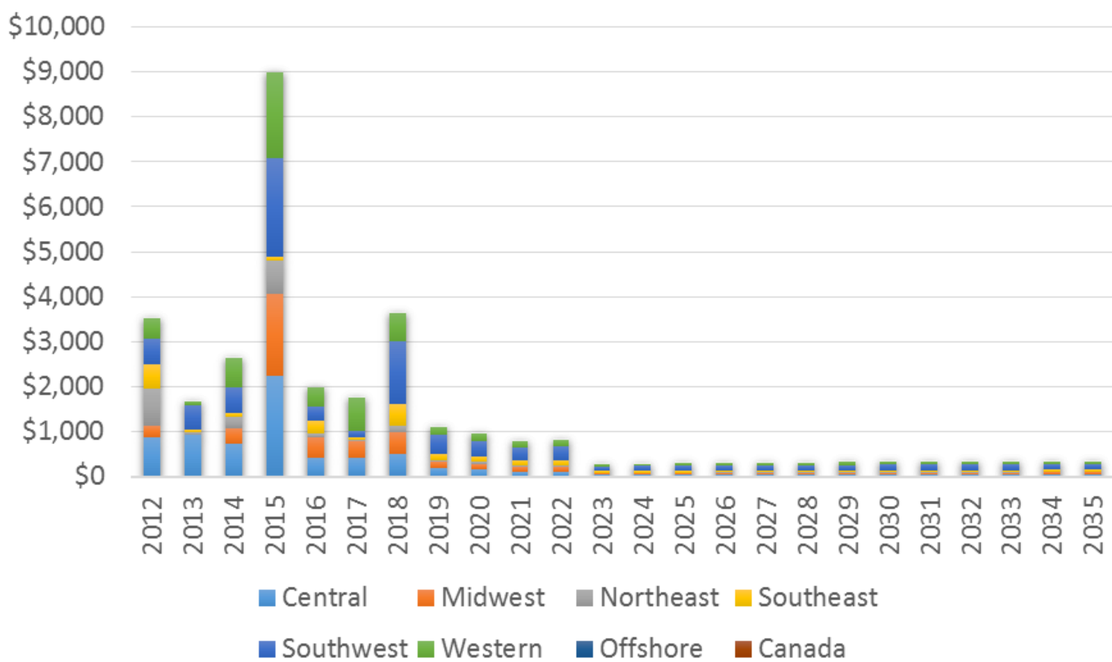


Exhibit 78: Refining and Oil Products Transport (Constant Unit Cost Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	Southwest	Western	Offshore	Alaska	Canada	US
2012	$885	$241	$819	$558	$552	$475	$0	$0	$0	$3,529
2013	$919	$22	$57	$53	$520	$91	$0	$0	$0	$1,662
2014	$729	$336	$273	$64	$577	$645	$0	$4	$0	$2,628
2015	$2,252	$1,818	$742	$88	$2,184	$1,913	$0	$13	$0	$9,010
2016	$427	$450	$79	$282	$331	$403	$0	$0	$0	$1,971
2017	$405	$393	$13	$62	$144	$739	$0	$4	$0	$1,760
2018	$488	$461	$137	$476	$1,346	$573	$0	$6	$0	$3,487
2019	$169	$124	$46	$125	$388	$168	$0	$2	$0	$1,022
2020	$148	$99	$40	$99	$319	$139	$0	$1	$0	$846
2021	$88	$93	$25	$97	$265	$112	$0	$1	$0	$681
2022	$88	$92	$25	$96	$263	$111	$0	$1	$0	$678
2023	$29	$30	$8	$31	$85	$36	$0	$0	$0	$220
2024	$29	$30	$8	$31	$85	$36	$0	$0	$0	$220
2025	$29	$30	$8	$31	$85	$36	$0	$0	$0	$220
2026	$29	$30	$8	$31	$85	$36	$0	$0	$0	$220
2027	$29	$30	$8	$31	$85	$36	$0	$0	$0	$220
2028	$29	$30	$8	$31	$85	$36	$0	$0	$0	$220
2029	$29	$30	$8	$31	$85	$36	$0	$0	$0	$220
2030	$29	$30	$8	$31	$85	$36	$0	$0	$0	$220
2031	$29	$30	$8	$31	$85	$36	$0	$0	$0	$220
2032	$29	$30	$8	$31	$85	$36	$0	$0	$0	$220
2033	$29	$30	$8	$31	$85	$36	$0	$0	$0	$220
2034	$29	$30	$8	$31	$85	$36	$0	$0	$0	$220
2035	$29	$30	$8	$31	$85	$36	$0	$0	$0	$220
Total 2013-2017	**$4,732**	**$3,018**	**$1,164**	**$549**	**$3,757**	**$3,790**	**$0**	**$21**	**$0**	**$17,031**
Total 2018-2035	**$1,352**	**$1,261**	**$380**	**$1,299**	**$3,690**	**$1,574**	**$0**	**$17**	**$0**	**$9,572**
Average 2012-2017	**$936**	**$543**	**$330**	**$184**	**$718**	**$711**	**$0**	**$4**	**$0**	**$3,427**
Average 2018-2035	**$75**	**$70**	**$21**	**$72**	**$205**	**$87**	**$0**	**$1**	**$0**	**$532**

Exhibit 79: Refining and Oil Products Transport (Escalating Unit Cost Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	Southwest	Western	Offshore	Alaska	Canada	US
2012	$885	$241	$819	$558	$552	$475	$0	$0	$0	$3,529
2013	$919	$22	$57	$53	$520	$91	$0	$0	$0	$1,662
2014	$729	$336	$273	$64	$577	$645	$0	$4	$0	$2,628
2015	$2,252	$1,818	$742	$88	$2,184	$1,913	$0	$13	$0	$9,010
2016	$427	$450	$79	$282	$331	$403	$0	$0	$0	$1,971
2017	$405	$393	$13	$62	$144	$739	$0	$4	$0	$1,760
2018	$514	$477	$143	$493	$1,395	$605	$0	$6	$0	$3,633
2019	$186	$133	$50	$135	$417	$187	$0	$2	$0	$1,109
2020	$171	$110	$45	$110	$355	$162	$0	$1	$0	$954
2021	$108	$105	$29	$111	$303	$137	$0	$1	$0	$795
2022	$112	$108	$30	$114	$311	$143	$0	$2	$0	$819
2023	$38	$36	$10	$38	$104	$48	$0	$1	$0	$275
2024	$39	$37	$10	$39	$107	$50	$0	$1	$0	$284
2025	$41	$38	$11	$40	$110	$52	$0	$1	$0	$293
2026	$43	$39	$11	$41	$113	$54	$0	$1	$0	$302
2027	$44	$40	$11	$42	$116	$56	$0	$1	$0	$310
2028	$45	$40	$12	$43	$118	$57	$0	$1	$0	$316
2029	$45	$41	$12	$44	$119	$58	$0	$1	$0	$319
2030	$46	$41	$12	$44	$120	$59	$0	$1	$0	$324
2031	$47	$41	$12	$44	$121	$60	$0	$1	$0	$327
2032	$47	$42	$12	$45	$123	$61	$0	$1	$0	$330
2033	$48	$42	$12	$45	$123	$61	$0	$1	$0	$333
2034	$48	$43	$12	$46	$125	$62	$0	$1	$0	$336
2035	$49	$43	$12	$46	$126	$63	$0	$1	$0	$339
Total 2013-2017	**$4,732**	**$3,018**	**$1,164**	**$549**	**$3,757**	**$3,790**	**$0**	**$21**	**$0**	**$17,031**
Total 2018-2035	**$1,671**	**$1,454**	**$448**	**$1,521**	**$4,305**	**$1,977**	**$0**	**$20**	**$0**	**$11,397**
Average 2013-2017	**$946**	**$604**	**$233**	**$110**	**$751**	**$758**	**$0**	**$4**	**$0**	**$3,406**
Average 2018-2035	**$93**	**$81**	**$25**	**$85**	**$239**	**$110**	**$0**	**$1**	**$0**	**$633**

Exhibit 80: Export Terminals (Constant Unit Cost Case), Millions of 2016$

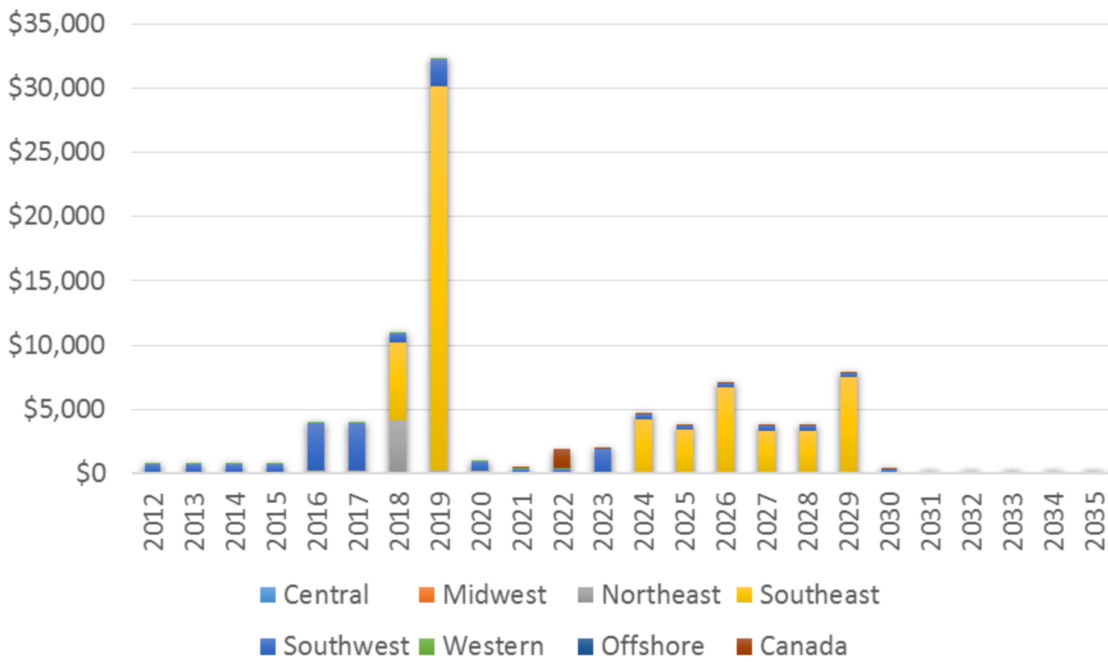


Exhibit 81: Export Terminals (Escalating Unit Cost Case), Millions of 2016$

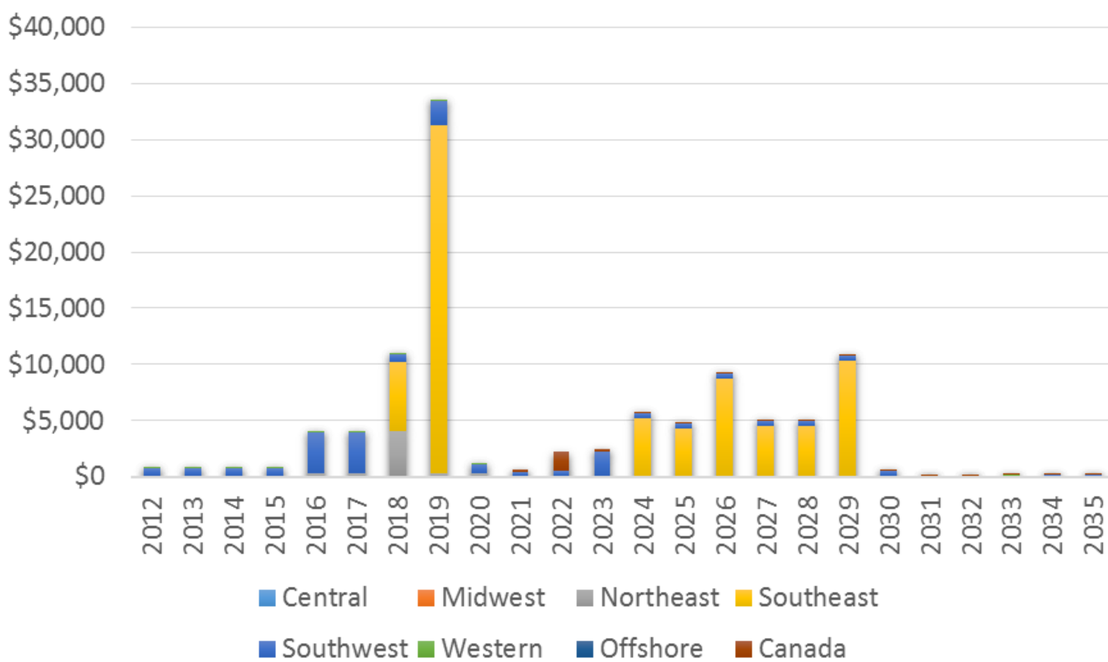


Exhibit 82: Export Terminals (Constant Unit Cost Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	Southwest	Western	Offshore	Alaska	Canada	US
2012	$0	$0	$71	$0	$694	$3	$0	$0	$0	$768
2013	$0	$0	$71	$0	$691	$3	$0	$0	$0	$764
2014	$0	$0	$71	$0	$689	$3	$0	$0	$0	$762
2015	$0	$0	$70	$0	$682	$3	$0	$0	$0	$755
2016	$0	$0	$286	$0	$3,658	$1	$0	$0	$0	$3,945
2017	$0	$0	$279	$0	$3,644	$1	$0	$0	$0	$3,924
2018	$0	$0	$4,079	$6,167	$644	$1	$0	$0	$0	$10,891
2019	$0	$0	$279	$29,833	$2,144	$1	$0	$0	$0	$32,257
2020	$0	$0	$279	$0	$644	$1	$0	$0	$0	$924
2021	$0	$0	$55	$0	$335	$2	$0	$0	$116	$392
2022	$0	$0	$55	$0	$335	$2	$0	$0	$1,511	$393
2023	$0	$0	$55	$0	$1,835	$2	$0	$0	$116	$1,893
2024	$0	$0	$55	$4,200	$335	$2	$0	$0	$116	$4,593
2025	$0	$0	$55	$3,333	$335	$2	$0	$0	$116	$3,727
2026	$0	$0	$39	$6,667	$317	$1	$0	$0	$15	$7,023
2027	$0	$0	$39	$3,333	$317	$1	$0	$0	$15	$3,690
2028	$0	$0	$39	$3,333	$317	$1	$0	$0	$15	$3,690
2029	$0	$0	$39	$7,500	$317	$1	$0	$0	$15	$7,857
2030	$0	$0	$39	$0	$317	$1	$0	$0	$15	$357
2031	$0	$0	$4	$0	$81	$0	$0	$0	$2	$85
2032	$0	$0	$4	$0	$81	$0	$0	$0	$2	$85
2033	$0	$0	$4	$0	$81	$0	$0	$0	$2	$85
2034	$0	$0	$4	$0	$81	$0	$0	$0	$2	$85
2035	$0	$0	$4	$0	$81	$0	$0	$0	$2	$85
Total 2013-2017	**$0**	**$0**	**$776**	**$0**	**$9,363**	**$11**	**$0**	**$0**	**$0**	**$10,151**
Total 2018-2035	**$0**	**$0**	**$5,128**	**$64,367**	**$8,594**	**$25**	**$0**	**$0**	**$2,058**	**$78,113**
Average 2012-2017	**$0**	**$0**	**$141**	**$0**	**$1,676**	**$2**	**$0**	**$0**	**$0**	**$1,820**
Average 2018-2035	**$0**	**$0**	**$285**	**$3,576**	**$477**	**$1**	**$0**	**$0**	**$114**	**$4,340**

Exhibit 83: Export Terminals (Escalating Unit Cost Case), Millions of 2016$

Year	Central	Midwest	Northeast	Southeast	Southwest	Western	Offshore	Alaska	Canada	US
2012	$0	$0	$71	$0	$694	$3	$0	$0	$0	$768
2013	$0	$0	$71	$0	$691	$3	$0	$0	$0	$764
2014	$0	$0	$71	$0	$689	$3	$0	$0	$0	$762
2015	$0	$0	$70	$0	$682	$3	$0	$0	$0	$755
2016	$0	$0	$286	$0	$3,658	$1	$0	$0	$0	$3,945
2017	$0	$0	$279	$0	$3,644	$1	$0	$0	$0	$3,924
2018	$0	$0	$4,092	$6,167	$674	$1	$0	$0	$0	$10,934
2019	$0	$0	$305	$30,929	$2,259	$1	$0	$0	$0	$33,495
2020	$0	$0	$318	$0	$734	$1	$0	$0	$0	$1,054
2021	$0	$0	$65	$0	$398	$3	$0	$0	$138	$466
2022	$0	$0	$68	$0	$414	$3	$0	$0	$1,789	$485
2023	$0	$0	$71	$0	$2,205	$3	$0	$0	$149	$2,279
2024	$0	$0	$74	$5,125	$446	$3	$0	$0	$154	$5,648
2025	$0	$0	$76	$4,190	$461	$3	$0	$0	$160	$4,731
2026	$0	$0	$55	$8,625	$450	$2	$0	$0	$21	$9,133
2027	$0	$0	$57	$4,414	$463	$2	$0	$0	$21	$4,936
2028	$0	$0	$58	$4,494	$472	$2	$0	$0	$22	$5,026
2029	$0	$0	$59	$10,213	$478	$2	$0	$0	$22	$10,751
2030	$0	$0	$59	$0	$485	$2	$0	$0	$23	$547
2031	$0	$0	$6	$0	$125	$1	$0	$0	$3	$132
2032	$0	$0	$6	$0	$126	$1	$0	$0	$3	$133
2033	$0	$0	$6	$0	$127	$1	$0	$0	$3	$134
2034	$0	$0	$6	$0	$129	$1	$0	$0	$3	$136
2035	$0	$0	$7	$0	$130	$1	$0	$0	$3	$137
Total 2013-2017	**$0**	**$0**	**$776**	**$0**	**$9,363**	**$11**	**$0**	**$0**	**$0**	**$10,151**
Total 2018-2035	**$0**	**$0**	**$5,389**	**$74,157**	**$10,577**	**$33**	**$0**	**$0**	**$2,512**	**$90,156**
Average 2013-2017	**$0**	**$0**	**$155**	**$0**	**$1,873**	**$2**	**$0**	**$0**	**$0**	**$2,030**
Average 2018-2035	**$0**	**$0**	**$299**	**$4,120**	**$588**	**$2**	**$0**	**$0**	**$140**	**$5,009**

Appendix D: Approximate Economic Impacts of Pipeline and Gathering CAPEX

This appendix approximates total U.S. economic impacts of new pipeline and gathering line infrastructure. Pipeline infrastructure includes oil, gas, NGL, and petroleum products transmission lines, compressors for gas transmission lines, and pumps for oil, NGL, and petroleum product lines. Gathering infrastructure includes oil and gas gathering pipes and compressors for gas gathering lines.

The approximate economic impacts (employment, GDP, and taxes) are calculated by multiplying the share of total CAPEX – i.e., the ratio of pipeline and gathering line CAPEX to the total oil, gas, and NGL infrastructure CAPEX – times the total oil, gas, and NGL infrastructure impacts. This method assumes the same impact per CAPEX (e.g. employment per dollar CAPEX) between all infrastructure categories. Actual economic impact, however, varies between the type of oil and gas infrastructure on the order of plus/minus 10%.

Exhibit 84 shows the economic impacts of pipeline and gathering CAPEX. The projected pipeline and gathering line CAPEX that averages about $22 billion per year and estimated to produce an average of over 325,000 U.S. jobs per year. This investment is expected to contribute over $565 billion to U.S. GDP, about $106 billion in Federal taxes, and roughly $91 billion in state and local taxes over the 2018-2035 projection period, which equate to average annual values of roughly $31 billion, $6 billion, and $5 billion, respectively.

Exhibit 84: Approximate Economic Impacts of Pipeline and Gathering CAPEX in Millions of 2016$

	Average Historical, 2013-2017	Average Projected, 2018-2035	Total Historical, 2013-2017	Total Projected, 2018-2035
CAPEX	$30,326	$22,340	$151,628	$402,125
Total Employment	439,746	324,608	NA	NA
Direct Employment	146,851	108,458	NA	NA
Indirect Employment	115,187	84,907	NA	NA
Induced Employment	177,708	131,244	NA	NA
U.S. Gross Domestic Product	$42,593	$31,404	$212,963	$565,266
Federal Taxes	$7,354	$5,900	$36,772	$106,200
State and Local Taxes	$6,740	$5,073	$33,700	$91,322

Appendix E: Regional Natural Gas Demand and Oil, Gas and NGL Production

Exhibit 85: Regional Natural Gas Demand (Billion Cubic Feet per Day)

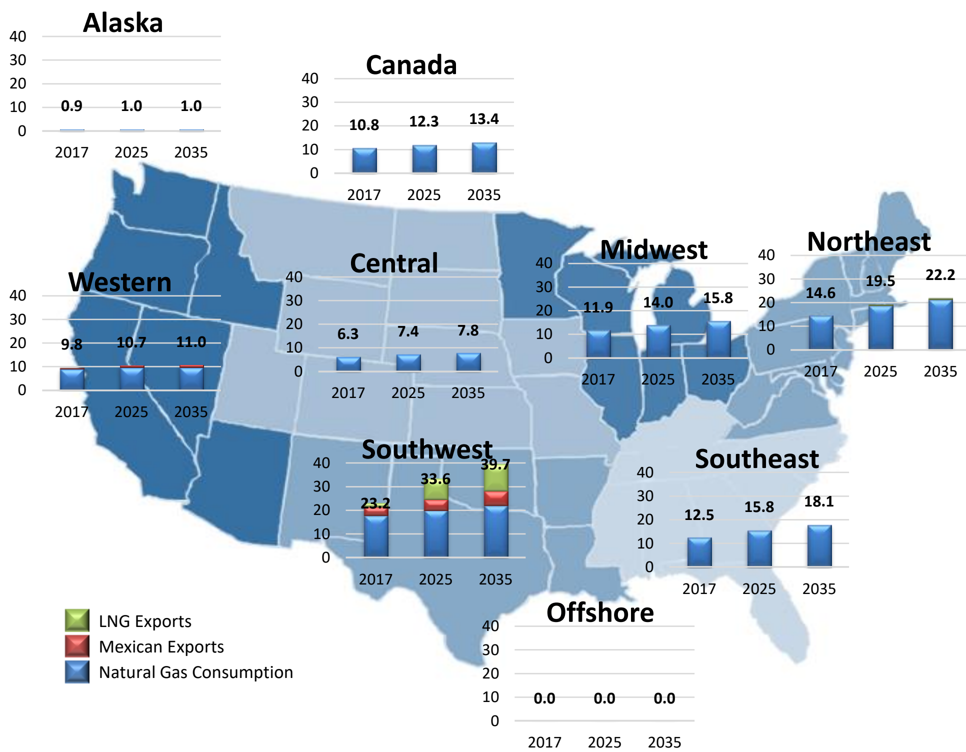


Exhibit 86: Regional Natural Gas Production (Billion Cubic Feet per Day)

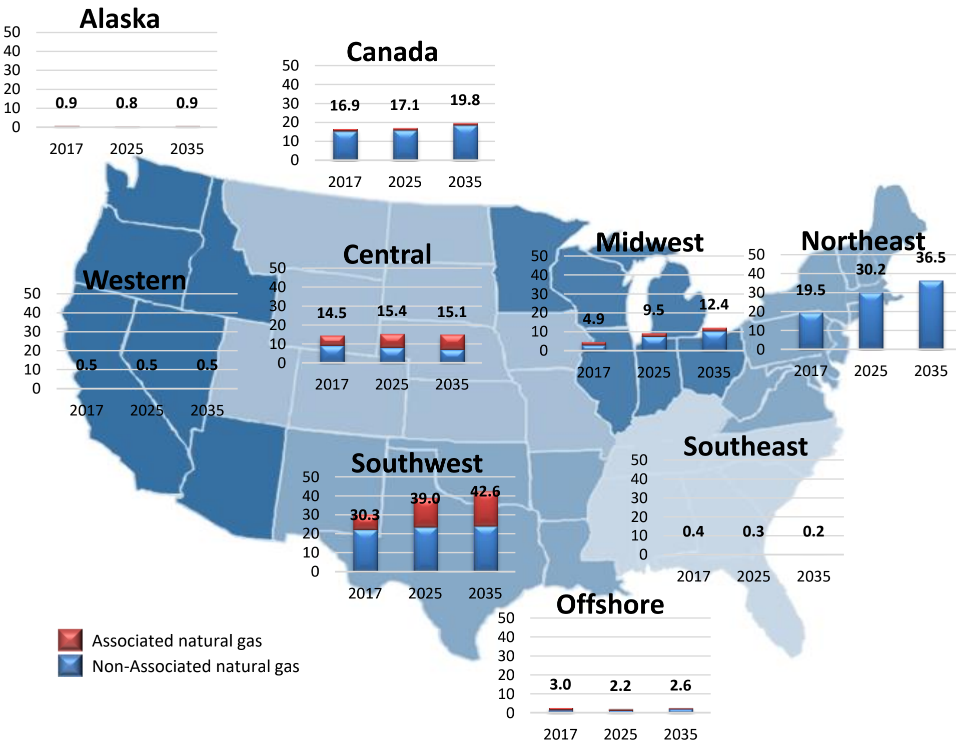


Exhibit 87: Regional NGL Production (Million Barrel per Day)

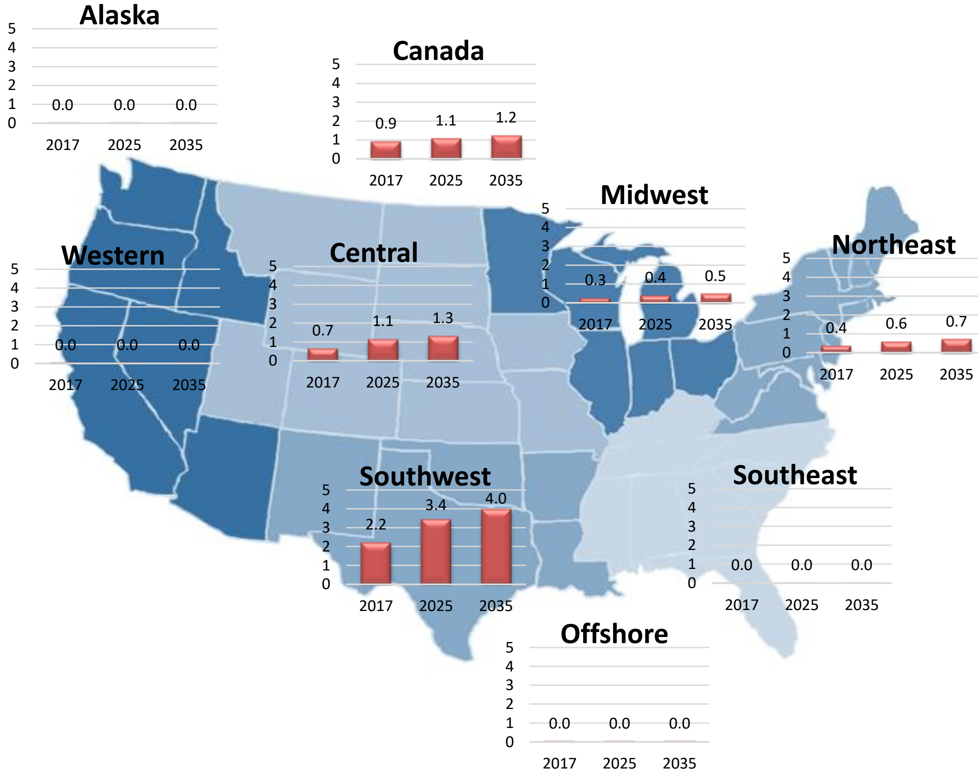
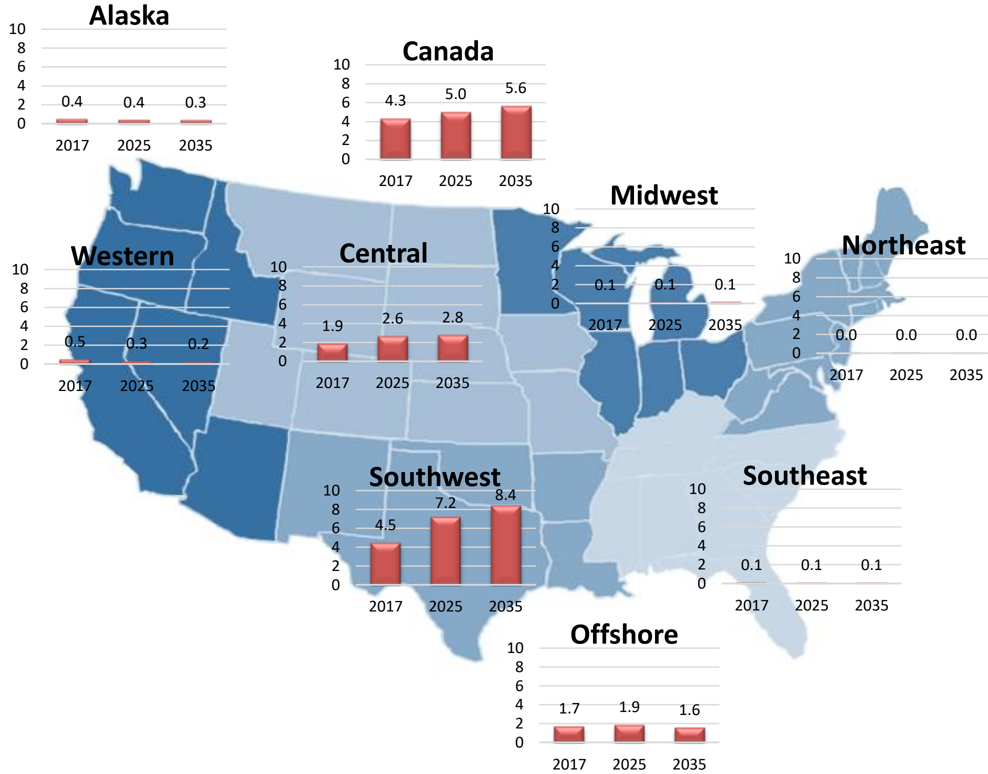


Exhibit 88: Regional Crude Oil Production (Million Barrel per Day)



Appendix F: Presentation of Additional Data, Charts and Graphs

Pipeline Construction Cost (2016$ per Inch-Mile) - Constant Unit Cost Case

	Year	U.S.	New England	Northeast (NY, NJ)	Pennsylvania	Mid Atlantic	Southeast	Florida	Midwest	South Central	Central/Mountain	Pacific Northwest	California
Historical Data	2000	$65,595	$217,511	$119,003		$55,733	$77,425	$80,612		$25,301	$36,241	$67,079	$61,394
	2001	$55,440		$95,831	$84,677	$51,902	$64,427	$162,841	$68,477		$49,466	$69,644	$46,447
	2002	$58,304	$524,223	$67,205	$86,858	$71,357	$71,632	$409,681	$57,410	$77,896	$34,037	$1,587,181	
	2003	$81,100	$323,536		$92,961	$495,625	$87,524		$121,235	$62,066	$52,727	$203,125	
	2004	$87,788	$415,355	$170,167	$84,684	$109,700	$106,618	$119,339	$90,239	$109,592	$45,452	$122,893	$55,582
	2005	$66,730	$253,797	$94,846	$134,334	$84,809	$74,679	$107,266	$102,164	$59,459	$56,779		$73,688
	2006	$84,788					$78,354		$80,301	$89,561	$61,827		
	2007	$109,156	$405,818	$620,070	$209,985		$67,299			$68,619	$77,145	$154,274	
	2008	$68,083	$321,385	$422,668	$108,217	$217,086	$127,593		$146,625		$75,375	$101,829	
	2009	$148,422	$134,468		$131,043		$179,172			$126,625	$246,653		
	2010	$111,656	$750,271		$156,318					$110,587	$84,744		
	2011	$118,999			$149,573		$112,103		$143,415	$101,194	$84,370	$129,284	
	2012	$142,914		$414,225	$133,296		$95,079	$465,039		$117,123	$115,586		$308,531
	2013	$218,603	$573,689	$390,662	$207,304	$369,964	$10,026	$227,427	$161,773	$219,281	$132,678	$170,160	$238,668
	2014	$130,068			$193,247	$266,028	$94,326	$1,155,413		$114,372	$89,964		$403,035
	2015	$221,713		$568,032	$175,283	$103,617	$279,170		$172,225		$108,407	$118,454	
	2016	$356,149	$629,279	$663,910	$222,300	$253,541	$188,611			$156,952	$199,288		
Projection	2017	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2018	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2019	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2020	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2021	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2022	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2023	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2024	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2025	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2026	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2027	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2028	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2029	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2030	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2031	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2032	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2033	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2034	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2035	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264

Pipeline Construction Cost (2016$ per Inch-Mile) - Escalating Unit Cost Case

	Year	U.S.	New England	Northeast (NY, NJ)	Pennsylvania	Mid Atlantic	Southeast	Florida	Midwest	South Central	Central/Mountain	Pacific Northwest	California
Historical Data	2000	$65,595	$217,511	$119,003		$55,733	$77,425	$80,612		$25,301	$36,241	$67,079	$61,394
	2001	$55,440		$95,831	$84,677	$51,902	$64,427	$162,841	$68,477		$49,466	$69,644	$46,447
	2002	$58,304	$524,223	$67,205	$86,858	$71,357	$71,632	$409,681	$57,410	$77,896	$34,037	$1,587,181	
	2003	$81,100	$323,536		$92,961	$495,625	$87,524		$121,235	$62,066	$52,727	$203,125	
	2004	$87,788	$415,355	$170,167	$84,684	$109,700	$106,618	$119,339	$90,239	$109,592	$45,452	$122,893	$55,582
	2005	$66,730	$253,797	$94,846	$134,334	$84,809	$74,679	$107,266	$102,164	$59,459	$56,779		$73,688
	2006	$84,788					$78,354		$80,301	$89,561	$61,827		
	2007	$109,156	$405,818	$620,070	$209,985		$67,299			$68,619	$77,145	$154,274	
	2008	$68,083	$321,385	$422,668	$108,217	$217,086	$127,593		$146,625		$75,375	$101,829	
	2009	$148,422	$134,468		$131,043		$179,172			$126,625	$246,653		
	2010	$111,656	$750,271		$156,318					$110,587	$84,744		
	2011	$118,999			$149,573		$112,103		$143,415	$101,194	$84,370	$129,284	
	2012	$142,914		$414,225	$133,296		$95,079	$465,039		$117,123	$115,586		$308,531
	2013	$218,603	$573,689	$390,662	$207,304	$369,964	$10,026	$227,427	$161,773	$219,281	$132,678	$170,160	$238,668
	2014	$130,068			$193,247	$266,028	$94,326	$1,155,413		$114,372	$89,964		$403,035
	2015	$221,713		$568,032	$175,283	$103,617	$279,170		$172,225		$108,407	$118,454	
	2016	$356,149	$629,279	$663,910	$222,300	$253,541	$188,611			$156,952	$199,288		
Projection	2017	$229,708	$660,011	$594,650	$198,123	$248,058	$159,502	$295,338	$177,970	$161,942	$137,381	$187,132	$400,264
	2018	$240,053	$680,754	$620,588	$203,770	$257,495	$164,654	$305,894	$183,457	$167,615	$142,947	$193,824	$422,666
	2019	$250,397	$701,498	$646,526	$209,418	$266,932	$169,806	$316,449	$188,943	$173,287	$148,513	$200,516	$445,068
	2020	$260,742	$722,242	$672,464	$215,065	$276,369	$174,958	$327,005	$194,429	$178,959	$154,080	$207,208	$467,471
	2021	$271,087	$742,986	$698,402	$220,713	$285,806	$180,109	$337,560	$199,915	$184,631	$159,646	$213,900	$489,873
	2022	$281,432	$763,730	$724,340	$226,360	$295,242	$185,261	$348,116	$205,402	$190,303	$165,212	$220,592	$512,275
	2023	$291,776	$784,473	$750,278	$232,008	$304,679	$190,413	$358,672	$210,888	$195,975	$170,779	$227,284	$534,677
	2024	$302,121	$805,217	$776,215	$237,655	$314,116	$195,564	$369,227	$216,374	$201,647	$176,345	$233,976	$557,079
	2025	$312,466	$825,961	$802,153	$243,303	$323,553	$200,716	$379,783	$221,860	$207,319	$181,911	$240,668	$579,482
	2026	$322,811	$846,705	$828,091	$248,951	$332,990	$205,868	$390,339	$227,346	$212,991	$187,478	$247,360	$601,884
	2027	$331,405	$863,938	$849,639	$253,642	$340,830	$210,148	$399,108	$231,904	$217,703	$192,102	$252,919	$620,494
	2028	$338,099	$877,361	$866,423	$257,297	$346,936	$213,481	$405,938	$235,454	$221,373	$195,704	$257,249	$634,990
	2029	$341,937	$885,057	$876,046	$259,392	$350,438	$215,393	$409,854	$237,490	$223,478	$197,769	$259,732	$643,302
	2030	$347,151	$895,513	$889,120	$262,239	$355,194	$217,989	$415,175	$240,255	$226,337	$200,575	$263,105	$654,593
	2031	$350,299	$901,826	$897,014	$263,957	$358,066	$219,557	$418,388	$241,925	$228,063	$202,269	$265,142	$661,411
	2032	$354,577	$910,403	$907,739	$266,293	$361,968	$221,687	$422,752	$244,193	$230,408	$204,570	$267,909	$670,675
	2033	$357,183	$915,630	$914,275	$267,716	$364,346	$222,985	$425,412	$245,576	$231,838	$205,973	$269,595	$676,319
	2034	$361,288	$923,860	$924,566	$269,956	$368,090	$225,029	$429,600	$247,752	$234,088	$208,181	$272,250	$685,208
	2035	$364,232	$929,764	$931,948	$271,564	$370,776	$226,496	$432,604	$249,314	$235,702	$209,766	$274,155	$691,583

Compressor Station Construction Cost (2016$ per HP) - Constant Unit Cost Case

	Year	U.S.	New England	Northeast (NY, NJ)	Pennsylvania	Mid Atlantic	Southeast	Florida	Midwest	South Central	Central/Mountain	Pacific Northwest	California
Historical Data	2000	$1,866		$2,722			$2,125	$1,544	$1,754		$2,402		$2,402
	2001	$1,840	$1,948			$1,542	$1,704	$1,516		$2,896	$2,323	$1,500	$1,970
	2002	$1,788	$3,185	$1,914		$1,440	$1,746	$2,420	$2,429	$1,531	$1,583	$2,170	$1,874
	2003	$1,833		$1,828		$2,911	$1,799		$3,055	$1,891	$1,352		$1,432
	2004	$1,988							$2,818	$2,095	$1,756		$1,998
	2005	$2,135		$2,346		$1,445	$2,393	$2,413	$1,673	$1,643	$2,367		$2,659
	2006	$1,986	$3,237	$2,486			$2,261	$2,132	$1,840	$1,535	$1,313		$1,520
	2007	$1,711					$2,504	$1,597	$1,422	$1,929	$1,551		$1,843
	2008	$2,132		$3,185		$5,758	$2,668		$3,101	$1,781	$1,894	$2,116	$2,481
	2009	$2,112		$2,435	$5,810	$2,235	$4,277	$2,331		$2,618	$1,668	$3,196	$2,158
	2010	$2,857						$3,597		$2,378	$4,057		$5,015
	2011	$2,669		$3,088	$1,613	$5,196			$3,282	$2,026	$4,191		$5,287
	2012	$2,776		$2,050	$2,987	$4,211	$3,283			$2,487	$3,732	$2,899	$3,289
	2013	$3,022	$4,097	$3,453	$3,011	$6,831	$3,463	$3,252	$4,933	$2,935	$3,745	$3,114	$3,343
	2014	$3,001		$3,102	$2,972	$5,196	$2,996				$3,674		$4,882
	2015	$2,913		$2,704	$2,721	$3,115	$4,430	$3,998	$3,322				
	2016	$2,958	$4,003	$4,721	$3,197	$6,116	$2,974		$1,913	$2,646			
Projection	2017	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2018	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2019	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2020	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2021	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2022	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2023	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2024	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2025	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2026	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2027	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2028	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2029	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2030	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2031	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2032	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2033	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2034	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2035	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675

Compressor Station Construction Cost (2016$ per HP) - Escalating Unit Cost Case

	Year	U.S.	New England	Northeast (NY, NJ)	Pennsylvania	Mid Atlantic	Southeast	Florida	Midwest	South Central	Central/Mountain	Pacific Northwest	California
Historical Data	2000	$1,866		$2,722			$2,125	$1,544	$1,754		$2,402		$2,402
	2001	$1,840	$1,948			$1,542	$1,704	$1,516		$2,896	$2,323	$1,500	$1,970
	2002	$1,788	$3,185	$1,914		$1,440	$1,746	$2,420	$2,429	$1,531	$1,583	$2,170	$1,874
	2003	$1,833		$1,828		$2,911	$1,799		$3,055	$1,891	$1,352		$1,432
	2004	$1,988							$2,818	$2,095	$1,756		$1,998
	2005	$2,135		$2,346		$1,445	$2,393	$2,413	$1,673	$1,643	$2,367		$2,659
	2006	$1,986	$3,237	$2,486			$2,261	$2,132	$1,840	$1,535	$1,313		$1,520
	2007	$1,711					$2,504	$1,597	$1,422	$1,929	$1,551		$1,843
	2008	$2,132		$3,185		$5,758	$2,668		$3,101	$1,781	$1,894	$2,116	$2,481
	2009	$2,112		$2,435	$5,810	$2,235	$4,277	$2,331		$2,618	$1,668	$3,196	$2,158
	2010	$2,857						$3,597		$2,378	$4,057		$5,015
	2011	$2,669		$3,088	$1,613	$5,196			$3,282	$2,026	$4,191		$5,287
	2012	$2,776		$2,050	$2,987	$4,211	$3,283			$2,487	$3,732	$2,899	$3,289
	2013	$3,022	$4,097	$3,453	$3,011	$6,831	$3,463	$3,252	$4,933	$2,935	$3,745	$3,114	$3,343
	2014	$3,001		$3,102	$2,972	$5,196	$2,996				$3,674		$4,882
	2015	$2,913		$2,704	$2,721	$3,115	$4,430	$3,998	$3,322				
	2016	$2,958	$4,003	$4,721	$3,197	$6,116	$2,974		$1,913	$2,646			
Projection	2017	$3,092	$4,205	$3,419	$3,030	$5,489	$3,729	$3,931	$3,347	$2,823	$4,562	$3,580	$5,675
	2018	$3,243	$4,384	$3,561	$3,230	$5,874	$3,922	$4,185	$3,479	$2,939	$4,919	$3,782	$6,138
	2019	$3,394	$4,563	$3,703	$3,429	$6,258	$4,115	$4,438	$3,612	$3,056	$5,276	$3,984	$6,602
	2020	$3,545	$4,742	$3,844	$3,629	$6,642	$4,309	$4,691	$3,744	$3,172	$5,633	$4,185	$7,065
	2021	$3,696	$4,921	$3,986	$3,828	$7,027	$4,502	$4,944	$3,876	$3,288	$5,990	$4,387	$7,528
	2022	$3,847	$5,100	$4,128	$4,028	$7,411	$4,695	$5,197	$4,008	$3,405	$6,347	$4,589	$7,991
	2023	$3,998	$5,278	$4,269	$4,227	$7,795	$4,889	$5,450	$4,141	$3,521	$6,704	$4,790	$8,454
	2024	$4,149	$5,457	$4,411	$4,427	$8,180	$5,082	$5,704	$4,273	$3,638	$7,060	$4,992	$8,917
	2025	$4,300	$5,636	$4,553	$4,626	$8,564	$5,275	$5,957	$4,405	$3,754	$7,417	$5,194	$9,380
	2026	$4,451	$5,815	$4,694	$4,826	$8,949	$5,469	$6,210	$4,537	$3,871	$7,774	$5,395	$9,844
	2027	$4,576	$5,964	$4,812	$4,992	$9,268	$5,629	$6,420	$4,647	$3,967	$8,071	$5,563	$10,228
	2028	$4,674	$6,080	$4,904	$5,121	$9,517	$5,754	$6,584	$4,733	$4,043	$8,302	$5,693	$10,528
	2029	$4,730	$6,146	$4,956	$5,195	$9,659	$5,826	$6,678	$4,782	$4,086	$8,434	$5,768	$10,700
	2030	$4,806	$6,236	$5,028	$5,295	$9,853	$5,924	$6,805	$4,849	$4,144	$8,614	$5,870	$10,933
	2031	$4,852	$6,291	$5,071	$5,356	$9,970	$5,982	$6,883	$4,889	$4,180	$8,723	$5,931	$11,074
	2032	$4,914	$6,365	$5,129	$5,439	$10,129	$6,062	$6,987	$4,944	$4,228	$8,870	$6,014	$11,266
	2033	$4,953	$6,410	$5,165	$5,489	$10,226	$6,111	$7,051	$4,977	$4,257	$8,960	$6,065	$11,382
	2034	$5,012	$6,481	$5,221	$5,568	$10,378	$6,188	$7,151	$5,029	$4,303	$9,102	$6,145	$11,566
	2035	$5,055	$6,531	$5,262	$5,625	$10,488	$6,243	$7,223	$5,067	$4,337	$9,204	$6,203	$11,698

The INGAA Foundation Inc.

Gathering Pipeline Cost (2016$/Inch-Mile By Diameter) - Constant Unit Cost Case

Year	Diameter (Inches)														
	1"	2"	4"	6"	8"	10"	12"	14"	16"	18"	20"	22"	24"	26"	28"	30"
2010	$46,753	$35,065	$29,221	$23,754	$24,131	$36,762	$62,212	$96,146	$100,388	$103,205	$106,022	$108,839	$111,656	$111,656	$111,656	$111,656
2011	$47,285	$35,464	$29,553	$24,381	$25,120	$38,789	$66,495	$105,283	$113,595	$114,946	$116,297	$117,648	$118,999	$118,999	$118,999	$118,999
2012	$47,881	$35,911	$29,926	$25,029	$26,117	$40,808	$70,733	$114,261	$126,503	$130,606	$134,708	$138,811	$142,914	$142,914	$142,914	$142,914
2013	$52,454	$39,341	$32,784	$27,419	$28,611	$44,705	$77,489	$125,174	$138,586	$158,590	$178,595	$198,599	$218,603	$218,603	$218,603	$218,603
2014	$55,073	$41,304	$34,420	$28,788	$30,040	$46,937	$81,357	$131,423	$145,504	$145,504	$145,504	$145,504	$145,504	$145,504	$145,504	$145,504
2015	$57,991	$43,493	$36,244	$30,313	$31,631	$49,424	$85,668	$138,387	$153,214	$170,339	$187,464	$204,588	$221,713	$221,713	$221,713	$221,713
2016	$60,696	$45,522	$37,935	$31,728	$33,107	$51,730	$89,665	$144,843	$160,362	$209,309	$258,256	$307,202	$356,149	$356,149	$356,149	$356,149
2017	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2018	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2019	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2020	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2021	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2022	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2023	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2024	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2025	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2026	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2027	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2028	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2029	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2030	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2031	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2032	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2033	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2034	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2035	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708

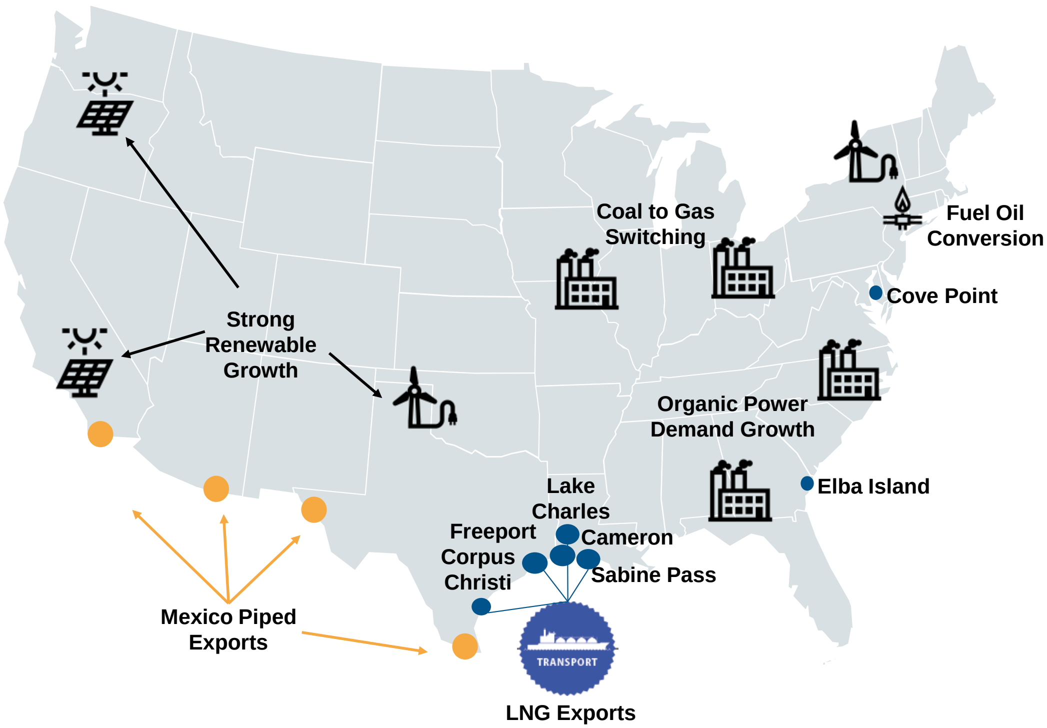
Gathering Pipeline Cost (2016$/Inch-Mile By Diameter) - Escalating Unit Cost Case

Year	Diameter (Inches)															
	1"	2"	4"	6"	8"	10"	12"	14"	16"	18"	20"	22"	24"	26"	28"	30"
2010	$46,753	$35,065	$29,221	$23,754	$24,131	$36,762	$62,212	$96,146	$100,388	$103,205	$106,022	$108,839	$111,656	$111,656	$111,656	$111,656
2011	$47,285	$35,464	$29,553	$24,381	$25,120	$38,789	$66,495	$105,283	$113,595	$114,946	$116,297	$117,648	$118,999	$118,999	$118,999	$118,999
2012	$47,881	$35,911	$29,926	$25,029	$26,117	$40,808	$70,733	$114,261	$126,503	$130,606	$134,708	$138,811	$142,914	$142,914	$142,914	$142,914
2013	$52,454	$39,341	$32,784	$27,419	$28,611	$44,705	$77,489	$125,174	$138,586	$158,590	$178,595	$198,599	$218,603	$218,603	$218,603	$218,603
2014	$55,073	$41,304	$34,420	$28,788	$30,040	$46,937	$81,357	$131,423	$145,504	$145,504	$145,504	$145,504	$145,504	$145,504	$145,504	$145,504
2015	$57,991	$43,493	$36,244	$30,313	$31,631	$49,424	$85,668	$138,387	$153,214	$170,339	$187,464	$204,588	$221,713	$221,713	$221,713	$221,713
2016	$60,696	$45,522	$37,935	$31,728	$33,107	$51,730	$89,665	$144,843	$160,362	$209,309	$258,256	$307,202	$356,149	$356,149	$356,149	$356,149
2017	$39,148	$29,361	$24,467	$20,464	$21,353	$33,364	$57,832	$93,420	$103,430	$134,999	$166,569	$198,138	$229,708	$229,708	$229,708	$229,708
2018	$40,911	$30,683	$25,569	$21,385	$22,315	$34,867	$60,436	$97,628	$108,088	$141,079	$174,070	$207,061	$240,053	$240,053	$240,053	$240,053
2019	$42,674	$32,005	$26,671	$22,307	$23,277	$36,370	$63,041	$101,835	$112,746	$147,159	$181,571	$215,984	$250,397	$250,397	$250,397	$250,397
2020	$44,437	$33,327	$27,773	$23,228	$24,238	$37,872	$65,645	$106,042	$117,404	$153,238	$189,073	$224,907	$260,742	$260,742	$260,742	$260,742
2021	$46,200	$34,650	$28,875	$24,150	$25,200	$39,375	$68,249	$110,249	$122,061	$159,318	$196,574	$233,831	$271,087	$271,087	$271,087	$271,087
2022	$47,963	$35,972	$29,977	$25,071	$26,161	$40,877	$70,854	$114,456	$126,719	$165,397	$204,076	$242,754	$281,432	$281,432	$281,432	$281,432
2023	$49,726	$37,294	$31,078	$25,993	$27,123	$42,380	$73,458	$118,663	$131,377	$171,477	$211,577	$251,677	$291,776	$291,776	$291,776	$291,776
2024	$51,489	$38,616	$32,180	$26,914	$28,085	$43,882	$76,063	$122,870	$136,035	$177,557	$219,078	$260,600	$302,121	$302,121	$302,121	$302,121
2025	$53,252	$39,939	$33,282	$27,836	$29,046	$45,385	$78,667	$127,078	$140,693	$183,636	$226,580	$269,523	$312,466	$312,466	$312,466	$312,466
2026	$55,015	$41,261	$34,384	$28,758	$30,008	$46,887	$81,272	$131,285	$145,351	$189,716	$234,081	$278,446	$322,811	$322,811	$322,811	$322,811
2027	$56,479	$42,359	$35,299	$29,523	$30,807	$48,136	$83,435	$134,780	$149,221	$194,767	$240,313	$285,859	$331,405	$331,405	$331,405	$331,405
2028	$57,620	$43,215	$36,012	$30,120	$31,429	$49,108	$85,120	$137,502	$152,235	$198,701	$245,167	$291,633	$338,099	$338,099	$338,099	$338,099
2029	$58,274	$43,706	$36,421	$30,461	$31,786	$49,665	$86,087	$139,063	$153,963	$200,956	$247,950	$294,943	$341,937	$341,937	$341,937	$341,937
2030	$59,163	$44,372	$36,977	$30,926	$32,271	$50,423	$87,399	$141,184	$156,311	$204,021	$251,731	$299,441	$347,151	$347,151	$347,151	$347,151
2031	$59,699	$44,774	$37,312	$31,206	$32,563	$50,880	$88,192	$142,464	$157,728	$205,871	$254,014	$302,157	$350,299	$350,299	$350,299	$350,299
2032	$60,428	$45,321	$37,768	$31,587	$32,961	$51,501	$89,269	$144,204	$159,654	$208,385	$257,115	$305,846	$354,577	$354,577	$354,577	$354,577
2033	$60,872	$45,654	$38,045	$31,820	$33,203	$51,880	$89,925	$145,264	$160,828	$209,917	$259,006	$308,095	$357,183	$357,183	$357,183	$357,183
2034	$61,572	$46,179	$38,482	$32,185	$33,585	$52,476	$90,959	$146,933	$162,676	$212,329	$261,982	$311,635	$361,288	$361,288	$361,288	$361,288
2035	$62,074	$46,555	$38,796	$32,448	$33,858	$52,904	$91,700	$148,130	$164,002	$214,059	$264,117	$314,174	$364,232	$364,232	$364,232	$364,232

Key Assumptions – Natural Gas Demand

- Natural gas demand will come from “New Markets”
- Large demand growth in the Gulf Coast region is mostly driven by exports and increasing industrial sector demand.
- In the Middle Atlantic, East North Central and South Atlantic regions natural gas demand is expected to increase due to coal and nuclear retirements.
- State efforts at carbon reduction in the power sector and stringent RPS standards might limit long-term penetration of natural gas in the power sector in several key markets:
  - West coast states, New York, Oklahoma and Texas.

Key Sectors Impacting Future U.S. Natural Gas Demand



Key Assumptions – Natural Gas Supply and Midstream Development

- Current U.S. and Canada natural gas production is from over 400 trillion cubic feet (Tcf) of proven natural gas reserves.
- The substantial North American natural gas resource base, totaling roughly 3,500 Tcf of unproved plus discovered but undeveloped natural gas resource, can supply the U.S. and Canada natural gas markets for over 100 years (at current consumption levels).
- Shale natural gas accounts for over 50% of remaining recoverable natural gas resources.
- No significant restrictions on well permitting and fracturing are expected beyond restrictions that are currently in place. Maryland recently passed a law to ban hydraulic fracturing within the state.
- No significant hurricane disruptions are expected to natural gas supply. Modest disruptions are assumed, consistent with the average disruption over the past 20 years.
- Arctic projects (specifically Alaska and Mackenzie Valley natural gas pipelines) are not included in our projection.
- Near-term midstream infrastructure development is aligned with project announcements. Unplanned ("generic") projects are included when the market signals need of capacity (i.e., projected basis covers the unit cost of expansion).

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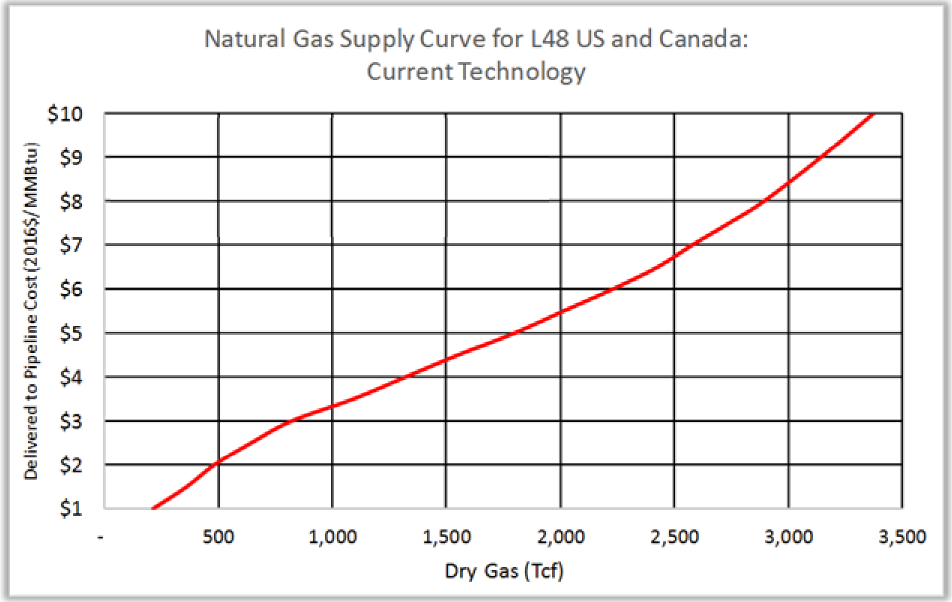
North American Natural Gas Resource Base

- This supply curve represents technically recoverable natural gas resource in the U.S. and Canada, assuming current E&P technologies on a "Henry Hub" price basis.
- The supply curve shows that a large component of the technically recoverable resource is economic at relatively low wellhead prices.
  - About 1,800 Tcf of natural gas resource is available at $5.00 per MMBtu, enough to supply the U.S. and Canada natural gas markets for over 50 years (at current consumption levels).
- The supply curve assessment is conservative in that it assumes no improvement in drilling and completion technology and cost reduction, while in fact, large improvements in these areas have been made historically and are expected in the future.
  - As technologies improve and new discoveries are made, the total natural gas resource is likely to grow.
  - Over 50% of the resource is natural gas from shale natural gas and tight oil plays.



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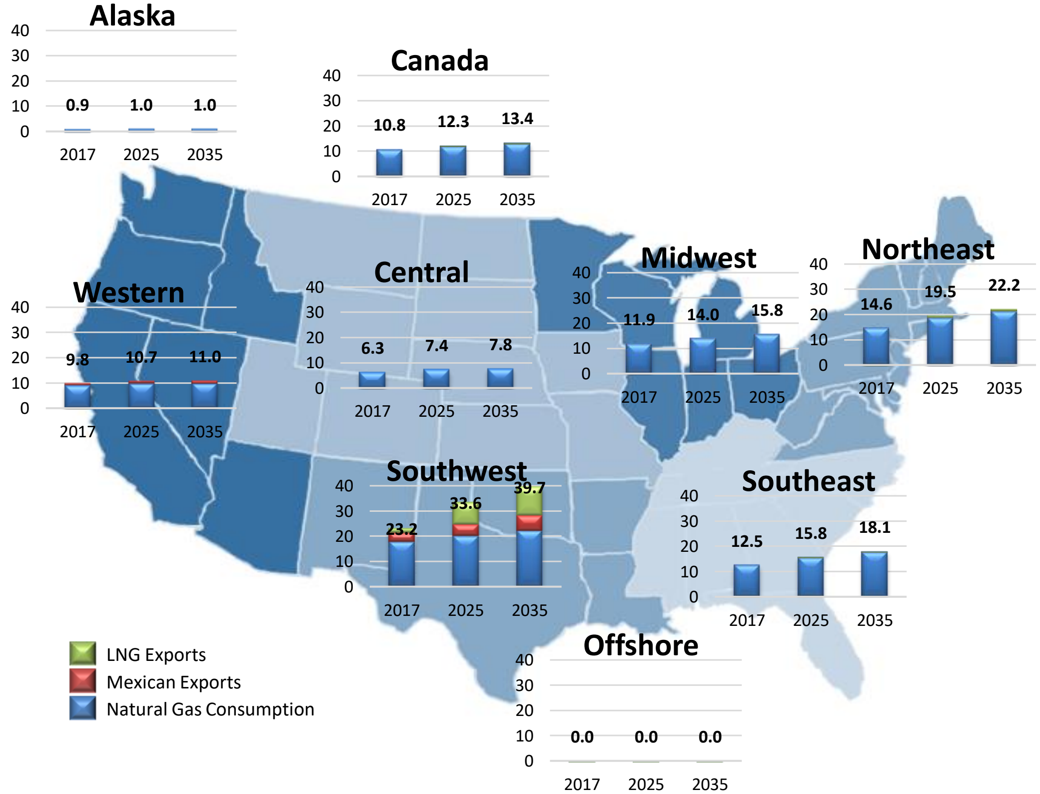
Summary of Key Market Trends

U.S. and Canada*	2017	2025	2035	% Change 2017 to 2025	% Change 2017 to 2035
Gas Consumption	84.3	98.7	109.2	17%	30%
Gas Use in Power Generation	27.8	36.8	44.7	32%	60%
Industrial	24.8	26.3	28.2	6%	14%
Residential & Commercial	23.9	26.5	26.0	11%	9%
Pipeline and Lease & Plant	7.7	9.1	10.4	18%	35%
Gas Production	90.4	114.6	130.1	27%	44%
Conventional Onshore Gas Production	21.6	14.4	11.6	-34%	-47%
Unconventional Onshore Gas Production	65.7	98.0	115.9	49%	76%
Shale Gas Production	*52.6*	*87.4*	*107.3*	*66%*	*104%*
Offshore Production	3.1	2.2	2.6	-28%	-16%
Net LNG Exports	1.3	9.9	12.4	656%	850%
Net Mexican Exports	4.3	5.5	7.2	27%	68%

**Does not include changes to storage (injection vs. withdrawal) and balancing items.*

Regional Natural Gas Demand* (Bcfd)

- U.S. Demand increases are due mostly to power generation growth, LNG exports and Mexico exports.
- Canada's natural gas demand growth is driven by increased industrial and power demand. The growth also includes BC LNG exports.



*Includes LNG Exports and Mexico Exports.

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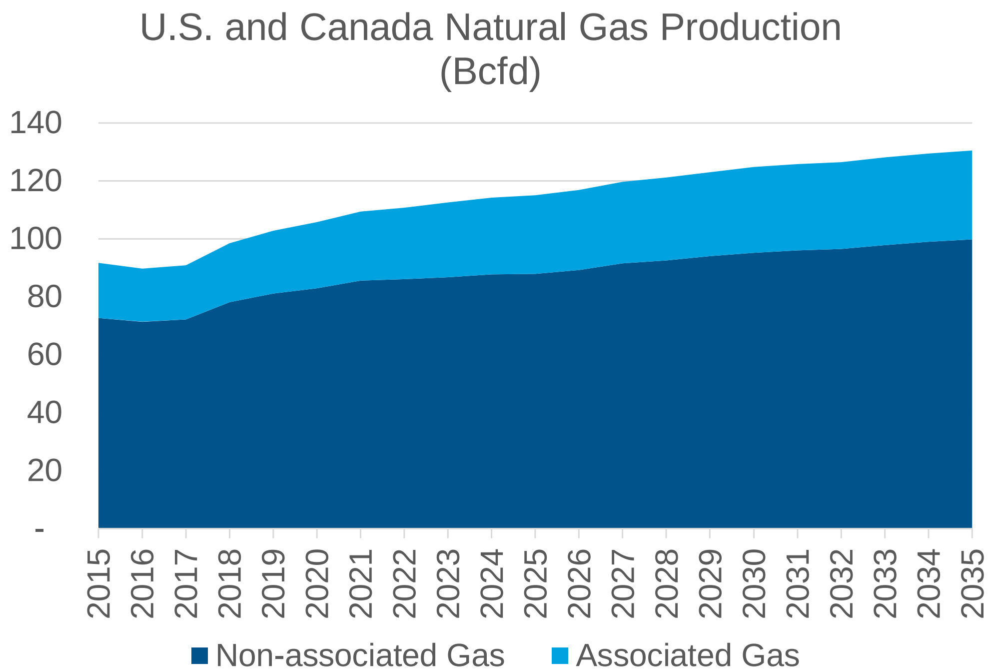
Natural Gas Production

- **Total Natural Gas production increases to 130 Bcfd by 2035.**
  - By 2021, shale natural gas production accounts for over 70% of all U.S. and Canada natural gas production.
  - Conventional production continues to decline by 2.9% annually.
  - About 70% of the shale natural gas production occurs in Marcellus/Utica, Haynesville, Barnett, Fayetteville, Eagle Ford and Western Canadian shale plays.



Non-associated natural gas refers to natural gas production from natural gas wells.
Associated natural gas refers to associated dissolved natural gas from oil wells.

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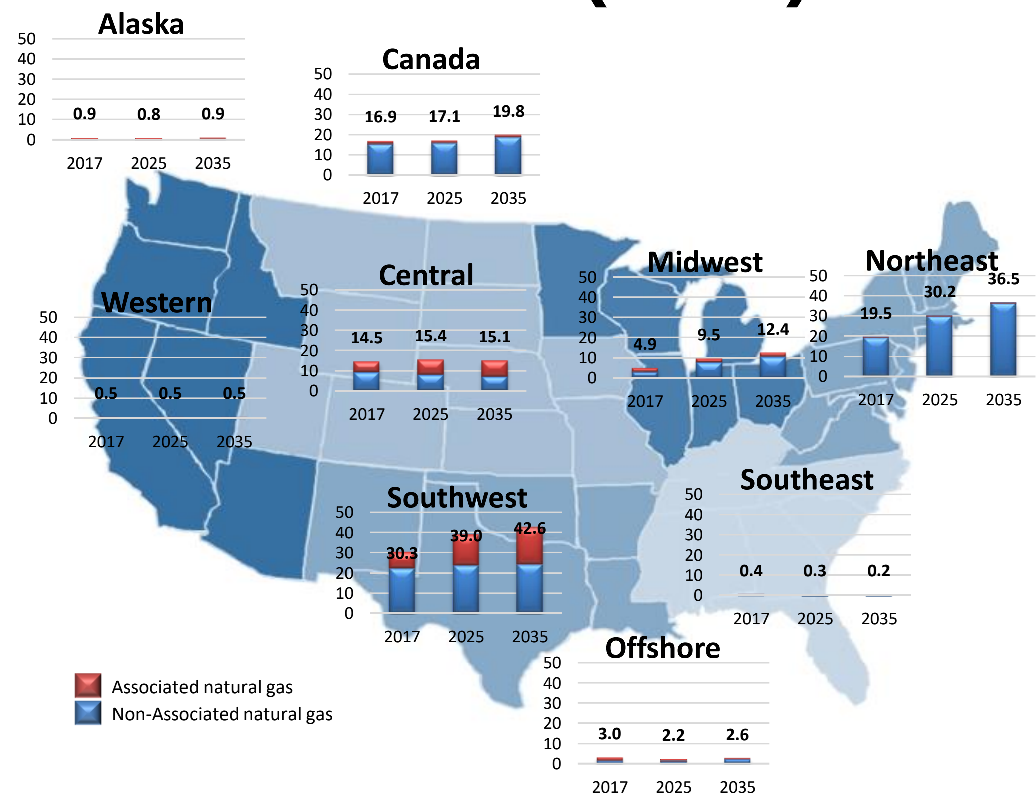
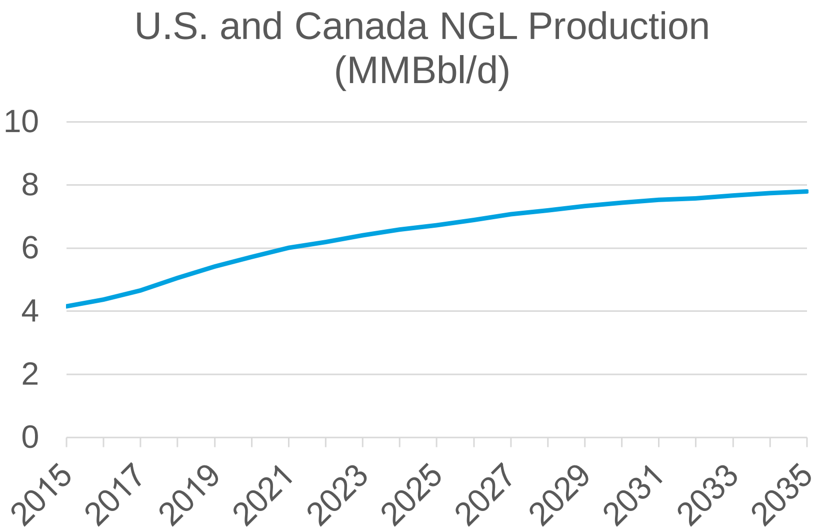
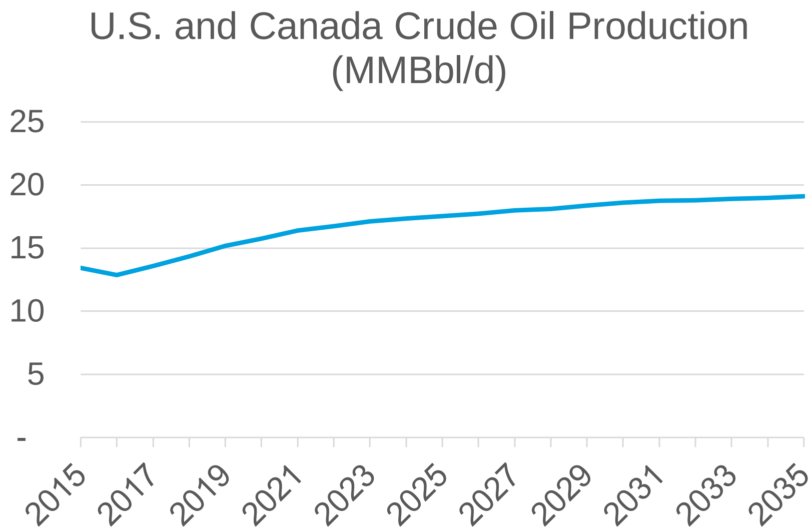
Regional Natural Gas Production (Bcfd)

- Northeast and Midwest growth is mostly from the Marcellus and Utica Shales.
- Growth in the Southwest is driven by production from the Woodford (including the SCOOP & STACK), Haynesville and Eagle Ford shale plays.
- Canada production growth is mostly from Horn River and Montney shale plays in British Columbia.
- Planned offshore projects result in slight increase in natural gas production.



Liquids Production





- **Natural Gas Liquids (NGL) production up by 65%.**
- **Oil production up by 40%.**

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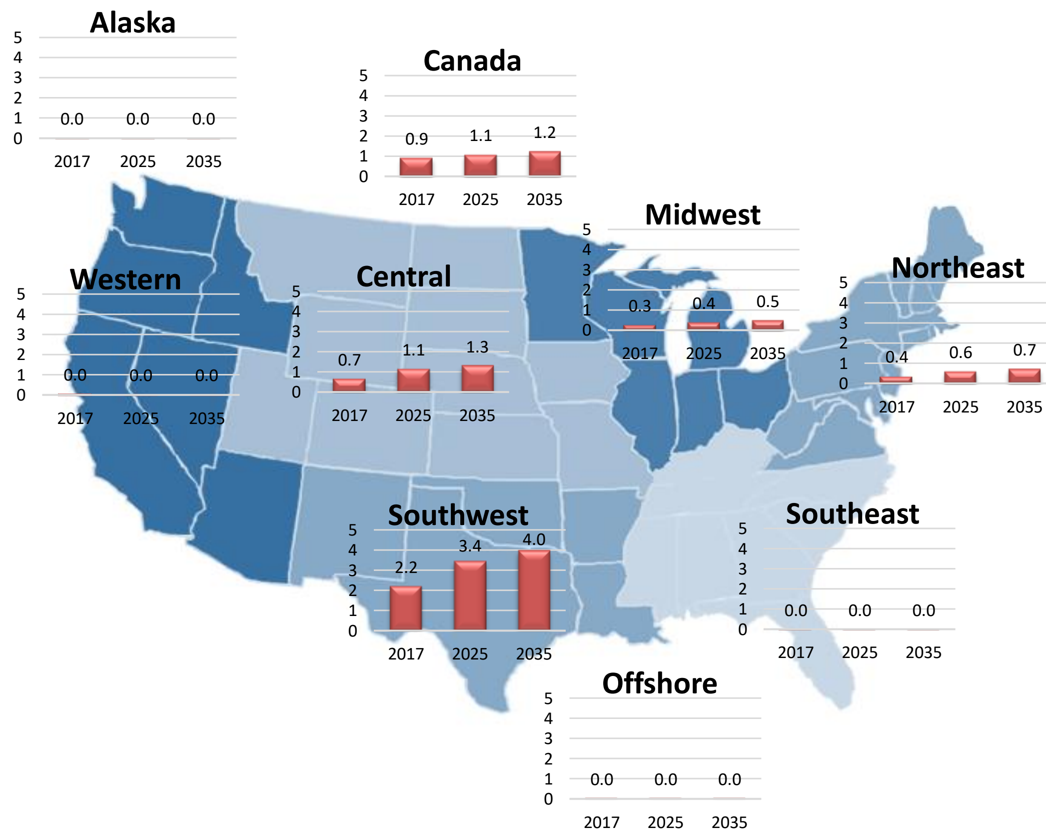
Regional NGLs Production (MMBPD)

- **Major NGL production growth regions include:**
  - Marcellus (Northeast).
  - Western Canada's Shales including the Montney and Horn River plays.
  - Permian, Woodford and Eagle Ford Shale (Southwest).
- **NGL production is dominated by growth in the Permian.**



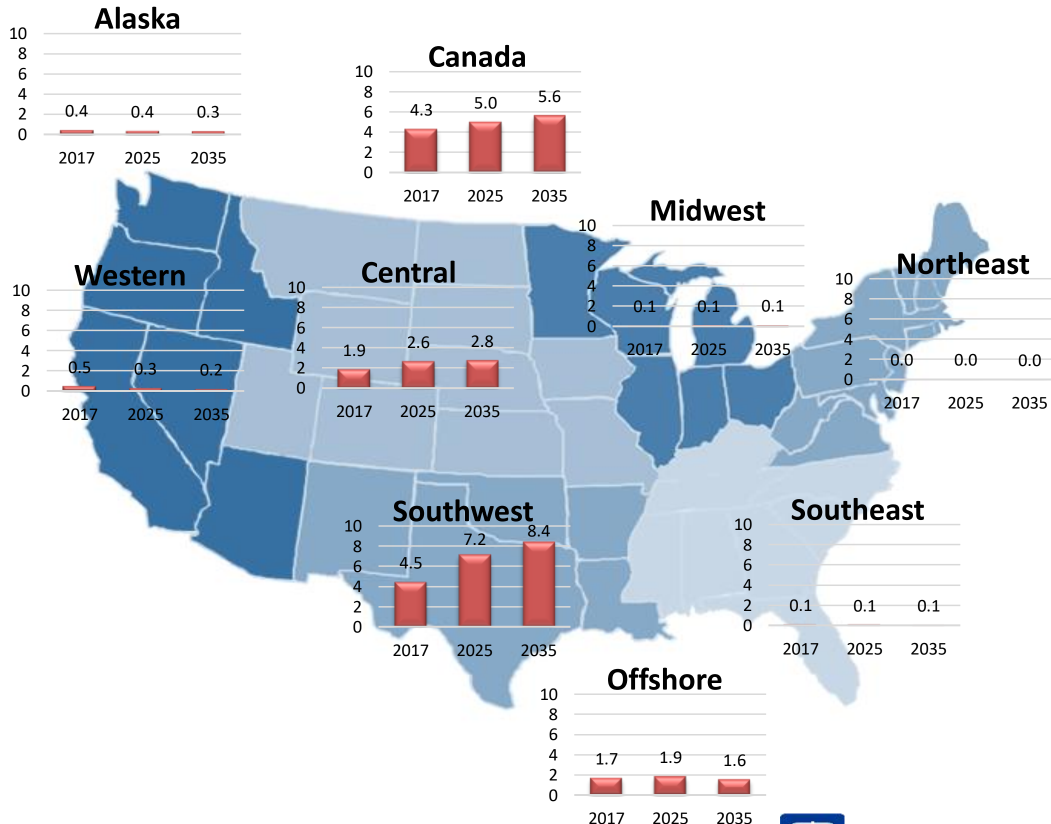
U.S. NGL Balance (MMBPD)

	Supply			Demand				
	Field Production	Refinery Products	Total	Ethane Crackers	PDH Facilities*	Exports	Domestic Consumption	Total
2015	3.3	1.1	4.4	0.6	0.1	1.0	2.8	4.4
2016	3.5	1.1	4.6	0.6	0.1	1.2	2.8	4.6
2017	3.6	1.1	4.7	0.7	0.1	1.2	2.8	4.7
2018	4.2	1.1	5.3	1.0	0.1	1.1	3.2	5.3
2019	4.5	1.3	5.8	1.1	0.1	1.3	3.3	5.8
2020	4.8	1.3	6.1	1.2	0.1	1.4	3.4	6.1
2021	5.1	1.1	6.2	1.3	0.1	1.4	3.4	6.2
2022	5.2	1.1	6.4	1.3	0.1	1.5	3.4	6.4
2023	5.4	1.1	6.5	1.3	0.1	1.7	3.4	6.5
2024	5.6	1.1	6.7	1.3	0.1	1.8	3.4	6.7
2025	5.7	1.1	6.8	1.4	0.1	1.9	3.4	6.8
2026	5.8	1.1	6.9	1.4	0.1	1.9	3.5	6.9
2027	6.0	1.1	7.1	1.4	0.1	2.1	3.4	7.1
2028	6.1	1.1	7.2	1.4	0.1	2.2	3.4	7.2
2029	6.2	1.1	7.3	1.4	0.1	2.3	3.4	7.3
2030	6.3	1.1	7.4	1.4	0.2	2.4	3.4	7.4
2031	6.4	1.1	7.5	1.5	0.2	2.3	3.5	7.5
2032	6.5	1.1	7.5	1.5	0.2	2.4	3.5	7.5
2033	6.5	1.1	7.6	1.5	0.2	2.5	3.5	7.6
2034	6.6	1.1	7.7	1.5	0.2	2.5	3.5	7.7
2035	6.6	1.1	7.7	1.5	0.2	2.6	3.5	7.7
Avg 2018-2035	**5.8**	**1.1**	**6.9**	**1.4**	**0.1**	**2.0**	**3.4**	**6.9**

**PDH facilities refer to propane dehydrogenation (PDH) plants that are dedicated to producing propylene from propane feedstock.*

Regional Crude Oil Production (MMBPD)

- Canada and Central and Southwest regions in the U.S. will see increased crude oil and condensate production.
- Canada production is expected to grow driven by oil sands production in Alberta.



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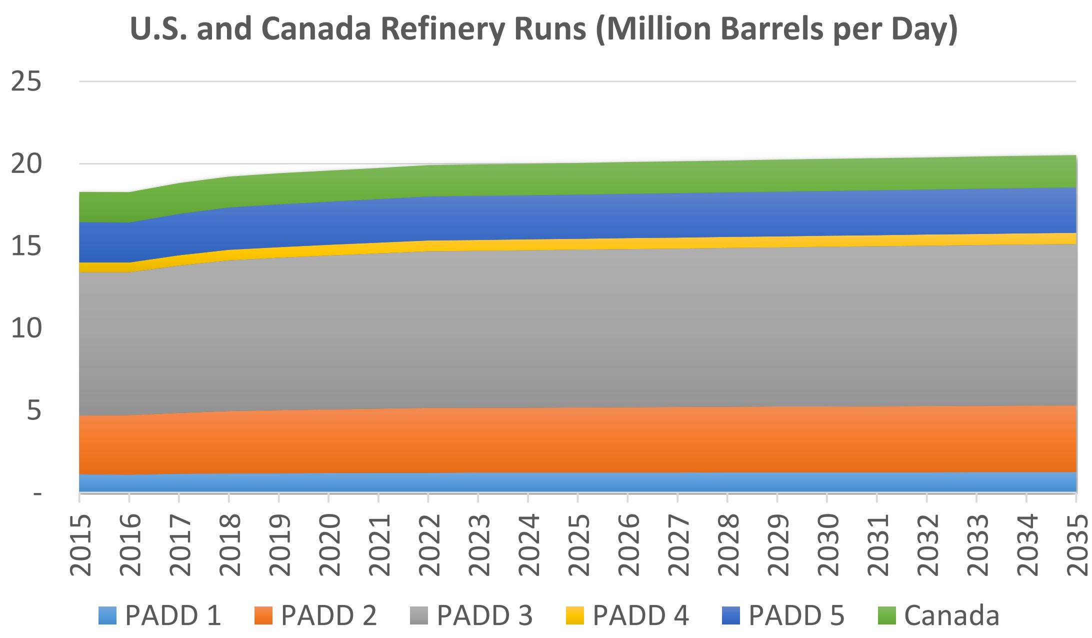
U.S. Crude Oil Balance (MMBPD)

	Production	Imports	Exports	Other Crude Supplies*	Refinery Runs
2015	9.4	7.4	0.5	0.1	16.5
2016	8.9	7.9	0.6	0.3	16.4
2017	9.2	7.9	1.1	0.9	16.9
2018	9.9	7.9	1.2	0.8	17.3
2019	10.6	7.8	1.3	0.4	17.5
2020	11.1	7.5	1.3	0.4	17.7
2021	11.7	7.2	1.4	0.4	17.8
2022	12.0	7.1	1.4	0.4	18.0
2023	12.3	6.8	1.5	0.4	18.0
2024	12.4	6.7	1.5	0.5	18.1
2025	12.5	6.7	1.5	0.4	18.1
2026	12.6	6.7	1.5	0.4	18.2
2027	12.8	6.6	1.5	0.3	18.2
2028	12.9	6.6	1.6	0.3	18.3
2029	13.0	6.5	1.6	0.3	18.3
2030	13.2	6.4	1.6	0.3	18.3
2031	13.3	6.4	1.6	0.3	18.4
2032	13.3	6.4	1.6	0.3	18.4
2033	13.4	6.4	1.6	0.3	18.5
2034	13.4	6.4	1.6	0.3	18.5
2035	13.5	6.4	1.6	0.3	18.6
Avg 2018-2035	**12.4**	**6.8**	**1.5**	**0.4**	**18.1**

**Changes to storage and balancing items.*

U.S. and Canada Refinery Runs*

- **U.S. and Canada refinery runs will continue to increase**
  - U.S. refinery runs grow from 16.9 million barrels per day (MMBPD) in 2017 to 18.6 MMBPD by 2035.
  - Canada refinery runs grow from 1.9 MMBPD in 2017 to 2.0 MMBPD by 2035.



**Refinery runs correspond to the quantity of crude oil processed in the refinery.*

Comparison of Key Differences with the 2016 INGAA Study

- **Current study assesses future capital expenditures based on two unit costs scenarios, the Constant Unit Cost and the Escalating Unit Cost. The unit costs in both of the scenarios, especially in the Escalating Unit Cost, are much higher compared to the unit costs in the prior 2016 study. This results in much higher CAPEX relative to the prior study.**
  - The prior 2016 study considers two different oil gas market scenarios (Optimistic/High Case and Less-Optimistic/Low Case) and assumes the same constant unit costs projection (constant in real terms) for both scenarios.
  - Both the Constant Unit Cost and the Escalating Unit Cost scenarios have the same oil, gas and NGL market projections.
- **Current study includes new categories (offshore production platform, refined product pipelines and pumps, and crude oil rail cars) that were not assessed in the prior 2016 study. These new categories contribute between 21% and 23% of the total CAPEX.**
  - Spending in these new categories is about $8 billion per year or 21% to the total CAPEX in the Constant Unit Cost case and about $12 billion per year or 23% of the total CAPEX in the Escalating unit Cost case. Most of the spending is related to offshore platform construction activity.
- **Current study assumes higher productivity and estimated ultimate recovery (EUR) for new wells, resulting in fewer wells and lower investments in oil and gas lease equipment relative to the prior study.**
- **Current study assumes higher gas pipeline reversal projects to transport Marcellus and Utica gas to the Gulf Coast to accommodate larger growth in LNG and Mexican exports versus the 2016 Study. This results in higher gas pipeline capital expenditures relative to the prior Study.**
- **Current study assumes much higher oil production growth versus the 2016 Study driven by robust activity in the Permian, Niobrara and the Bakken tight oil plays. This results in greater investments in crude oil pipeline and storage.**
- **Increase in oil production growth leads to higher growth in associated gas and NGL production versus the prior study, resulting in higher investments in NGL fractionation and NGL export facilities.**

Comparison of CAPEX: Current Study Versus 2016 INGAA Study

Annual Average CAPEX (Billions of 2016$ per Year)	Current Study		2016 INGAA Study	
	Constant Unit Cost 2018-2035	Escalating Unit Cost 2018-2035	Low Case 2015-2035	High Case 2015-2035
Oil, Gas, and NGL Pipeline (includes compressors and pumps)	$13.1	$16.3	$6.0	$10.1
Gathering Line (includes compressors)	$4.0	$5.5	$2.9	$3.5
Oil and Gas Lease Equipment	$4.8	$6.7	$6.7	$8.2
Gas Storage Fields, Processing Plants, and LNG Export Facilities	$6.3	$7.5	$4.9	$5.6
NGL Fractionation and NGL Export Facilities	$1.7	$2.2	$1.1	$1.4
Crude Oil Storage Tanks	$0.1	$0.1	$0.0	$0.0
Other Oil Handling*	$8.0	$11.6	n/a	n/a
Total Capital Expenditures	**$38.0**	**$49.9**	**$21.6**	**$28.8**

**Offshore production platform, refined product pipelines and pumps, and crude oil rail cars*

Midstream Infrastructure Requirements
Natural Gas

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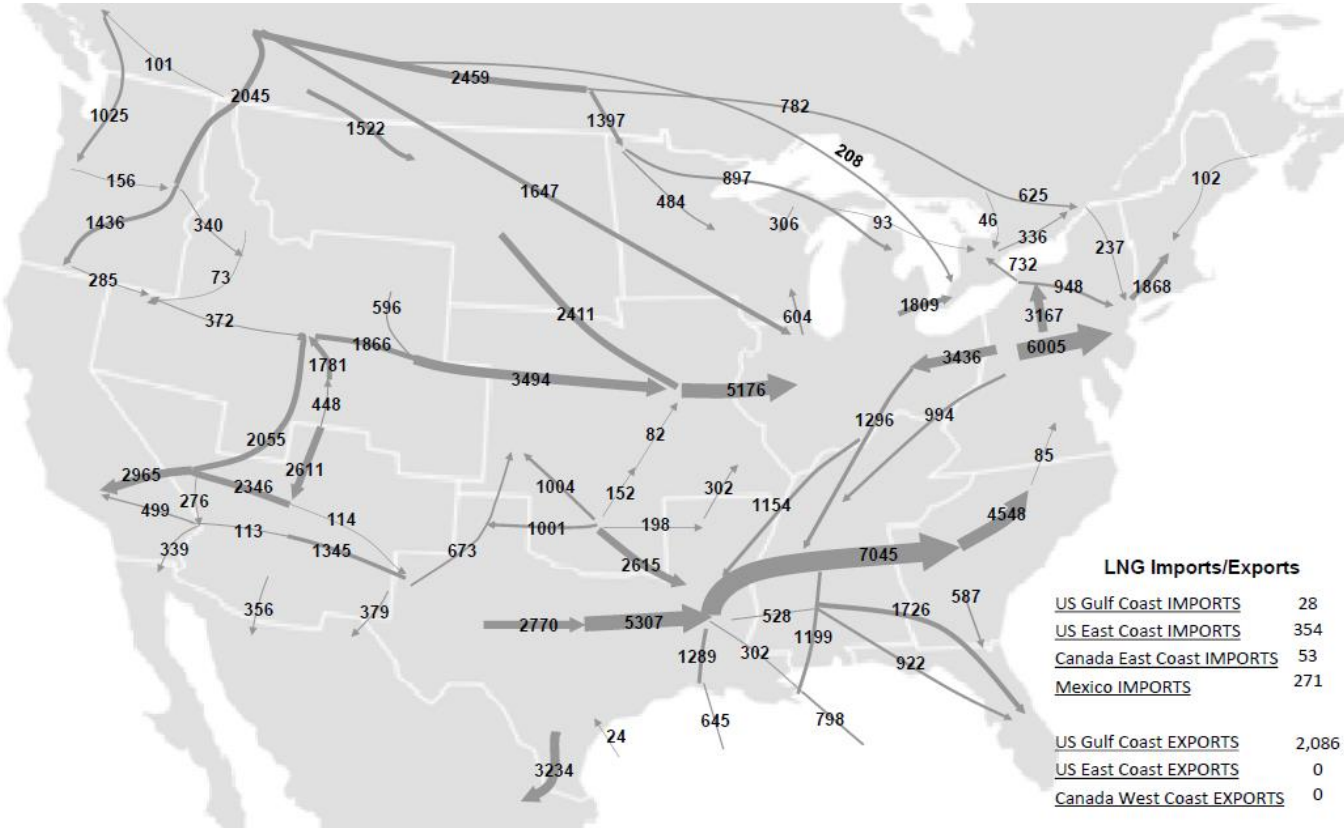
Natural Gas Flows in 2017 (MMcfd)



LNG Imports/Exports

US Gulf Coast IMPORTS	28
US East Coast IMPORTS	354
Canada East Coast IMPORTS	53
Mexico IMPORTS	271
US Gulf Coast EXPORTS	2,086
US East Coast EXPORTS	0
Canada West Coast EXPORTS	0

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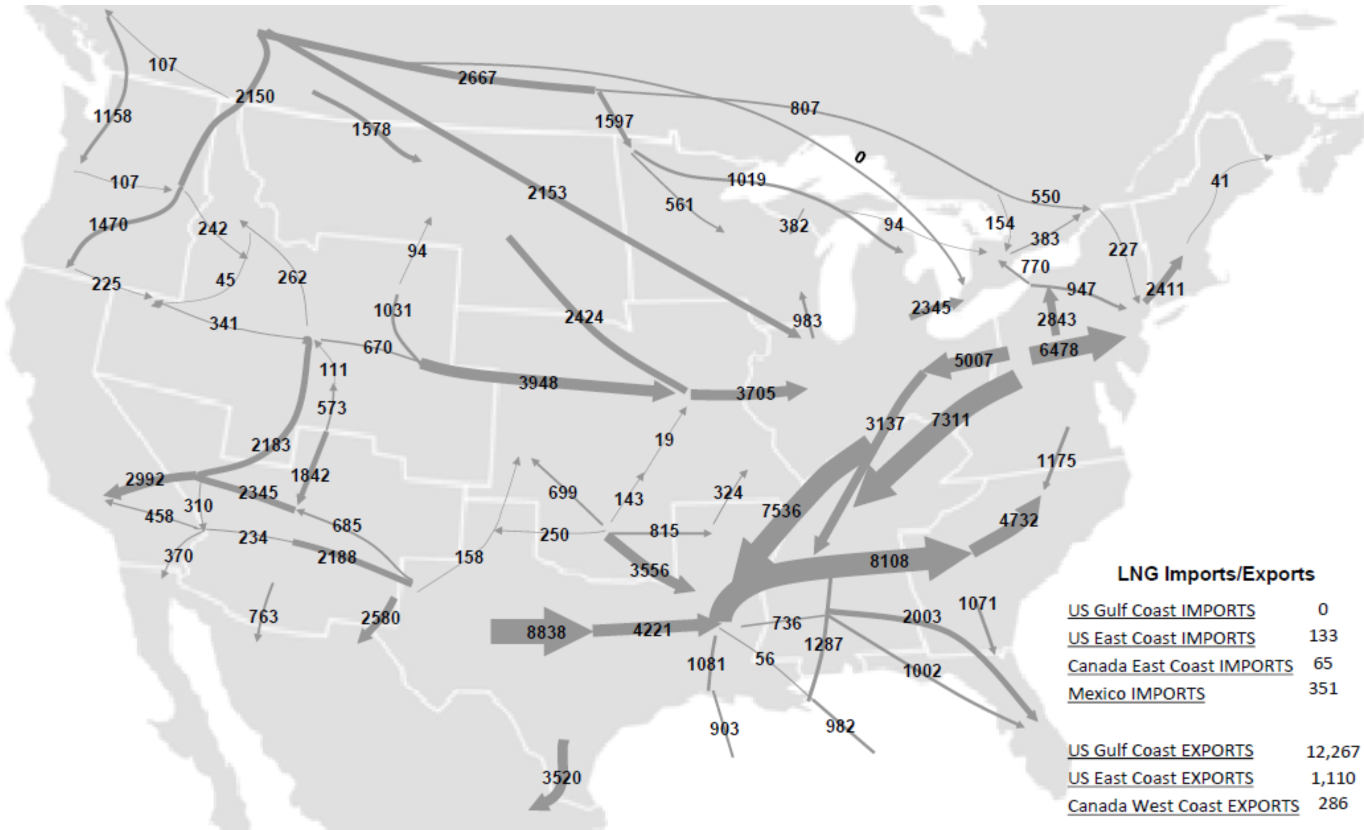
Natural Gas Flows in 2035 (MMcfd)



LNG Imports/Exports

US Gulf Coast IMPORTS	0
US East Coast IMPORTS	133
Canada East Coast IMPORTS	65
Mexico IMPORTS	351
US Gulf Coast EXPORTS	12,267
US East Coast EXPORTS	1,110
Canada West Coast EXPORTS	286

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Pipeline Capacity Added for Natural Gas Transport (Bcfd)

- **57 Bcfd of takeaway capacity projected.**
- **The majority of new capacity originates from the Marcellus & Utica and Permian Basin.**
- **Significant capacity required to accommodate growth in gas-fired generation and LNG and Mexican exports.**

Note: The "takeaway capacity" total includes the capacity of inter-regional pipelines that move natural gas from one region to another region, as well as intra-regional pipeline capacity. The capacity of intra-regional pipelines are included in this study because there are a number of new intra-regional pipeline projects designed to support production, particularly in the Marcellus/Utica region and in Canada.

Originating Region	2017	2018	2019-2020	2021-2025	2026-2030	2031-2035	Total 2018-2035	Average Annual 2018-2035
U.S. and Canada	15.0	19.6	18.1	4.3	9.2	5.5	56.7	3.1
U.S.	13.8	17.6	15.3	3.8	8.7	5.0	50.4	2.8
Canada	1.2	2.0	2.8	0.5	0.5	0.5	6.3	0.3
Central	0.1	0.4	0.9	1.6	1.3	0.5	4.6	0.3
Midwest	4.3	2.6	0.4	1.0	3.4	1.0	8.4	0.5
Northeast	1.7	6.6	3.6	1.0	3.0	2.5	16.7	0.9
Offshore	-	-	-	-	-	-	-	-
Southeast	4.2	2.4	0.8	0.2	-	-	3.3	0.2
Southwest	3.6	5.7	9.0	-	1.0	1.0	16.6	0.9
Western	-	-	0.7	-	-	-	0.7	0.0
Alaska	-	-	-	-	-	-	-	-

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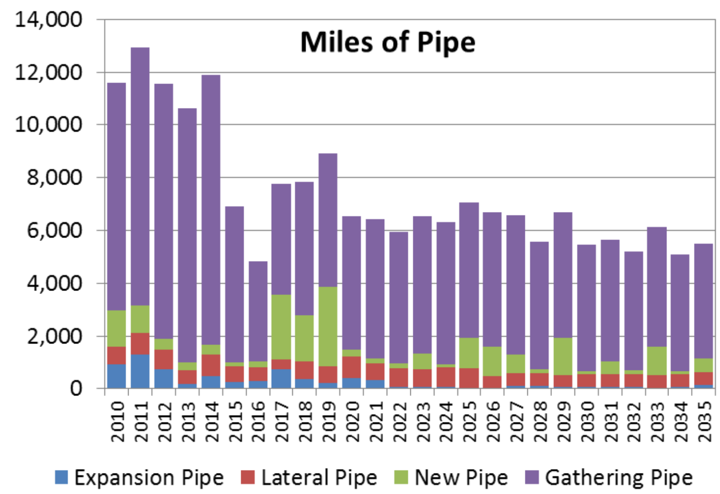
Natural Gas Metrics

	Both Cases 2018-2035
Natural Gas Well Completions (1000s)	144
Oil Well Completions (1000s)	369
Total Well Completions (1000s)	513
Miles of Transmission Mainline (1000s)	15.5
Miles of Laterals to/from Power Plants, Storage Fields and Processing Plants (1000s)	10.4
Power Plant Laterals (1000s)	*7.7*
Storage Laterals (1000s)	*0.3*
Processing Plant Laterals (1000s)	*2.4*
Miles of Natural Gas Gathering Line (1000s)	88.3
Inch-Miles of Transmission Mainline (1000s)	527
Inch-Miles of Laterals to/from Power Plants, Storage Fields and Processing Plants (1000s)	221
Inch-Miles of Power Plant Laterals (1000s)	*158*
Inch-Miles of Storage Laterals (1000s)	*9*
Inch-Miles of Processing Plant Laterals (1000s)	*54*
Inch-Miles of Gathering Line (1000s)	694
Compression for Pipeline (1000 HP)	7,041
Compression for Gathering Line (1000 HP)	8,540
Natural Gas Storage (Bcf Working Natural Gas)	246
Processing Capacity (Bcfd)	38.1
LNG Export Facilities (Bcfd)	12.9

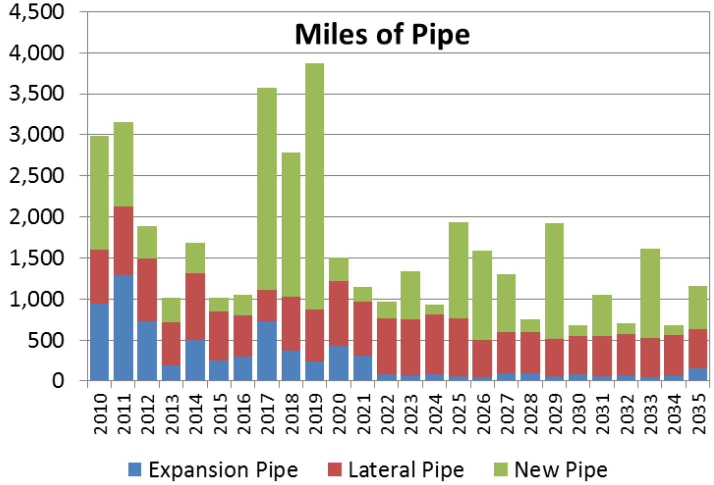
Miles of New Natural Gas Pipeline Added (Including Gathering Line)

- Approximately 115,000 miles of new pipeline will be added over the next 18 years. Gathering line accounts for roughly 80% of the total.
- Future buildout averages 6,300 miles per year, versus roughly 8,400 miles per year over the past five years, a decline of 30% from recent activity.



Miles of New Natural Gas Pipeline Added (Excluding Gathering Line)

- Approximately 26,000 miles of new natural gas pipelines from 2018 through 2035.
- Averaging 1,400 miles per year.
- Activity maintained by buildout from areas like the Marcellus and Utica.



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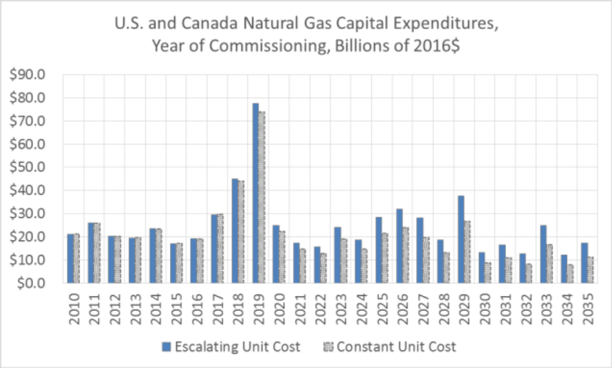
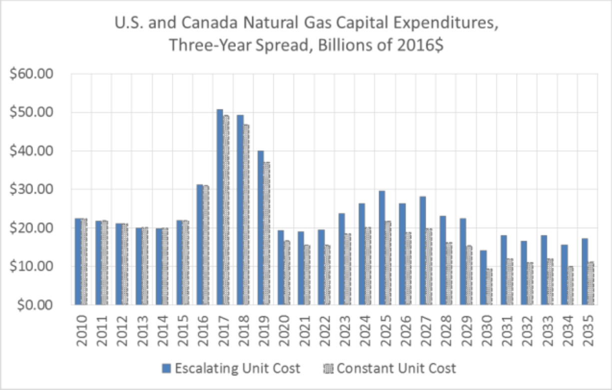
Natural Gas Capital Expenditures

(Billions of Real Dollars)	Constant Unit Cost 2018-2035	Escalating Unit Cost 2018-2035
Natural Gas Transmission Mainline Pipe	$107.5	$131.4
Lateral Pipe to/from Power Plants, Natural Gas Storage and Processing Plants	$46.1	$58.5
Power Plant Laterals	*$35.2*	*$45.3*
Storage Laterals	*$1.6*	*$1.9*
Processing Plant Laterals	*$9.3*	*$11.3*
Gathering Line (pipe only)	$40.2	$54.7
Gathering Line (compression)	$26.0	$35.2
Natural Gas Lease Equipment	$12.1	$16.8
Compression for Transmission Mainline	$24.8	$32.5
Natural Gas Storage Fields	$4.9	$5.9
Natural Gas Processing Capacity	$35.4	$46.6
LNG Export Facilities	$72.6	$82.9
Total Capital Expenditures	**$369.5**	**$464.6**

Natural Gas Capital Expenditure Trends

- Investments in 2018-2019 are robust in both cases as most of the projects are either under construction or well along in the planning stage.
- After 2019, the investments for natural gas infrastructure are much lower in both cases due to the robust buildout in the 2016-2019 period. Average investments are about a quarter of the investments during 2016-2019.
- The "Three-Year Spread" shows declining spending in natural gas infrastructure developments starting next year through 2022. Increased investments around 2025 in both cases is related to LNG export projects in Western Canada.
- In the subsequent slides, the capital expenditures are based on the "Year of Commissioning" methodology, unless otherwise noted.



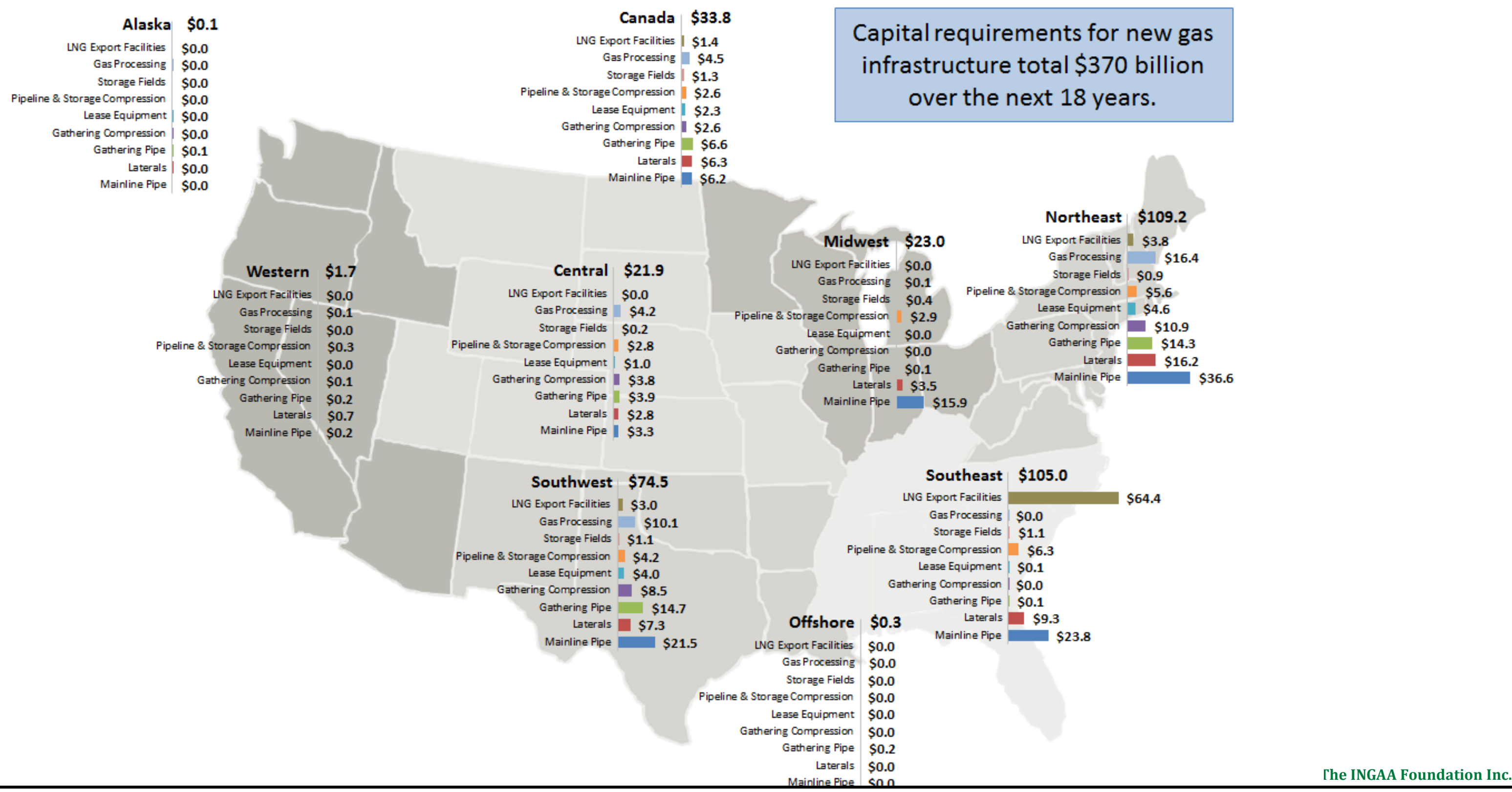


Regional Natural Gas Pipeline Capital Expenditures

Constant Unit Cost, 2018-2035	Central	Midwest	Northeast	Offshore	Southeast	Southwest	Western	Canada	Alaska	Total
Miles of Mainline (1000s)	0.9	2.6	4.0	0.0	3.4	3.8	0.1	0.8	0.0	15.5
Miles of Laterals (1000s)	1.2	0.9	2.9	0.0	2.0	2.1	0.2	1.1	0.0	10.4
Miles of Gathering Line (1000s)	16.8	0.3	9.8	0.3	0.5	44.5	1.3	14.8	0.1	88.3
Compression Transmission (1000 HP)	718	844	1,527	0	1,456	1,502	144	849	0	7,041
Compression Gathering Line (1000 HP)	840	12	3,581	4	4	3,023	25	1,050	2	8,540
CapEx Mainline (Billion 2016$)	$3.3	$15.9	$36.6	$0.0	$23.8	$21.5	$0.2	$6.2	$0.0	$107.5
CapEx Laterals (Billion 2016$)	$2.8	$3.5	$16.2	$0.0	$9.3	$7.3	$0.7	$6.3	$0.0	$46.1
CapEx Gathering Line (Billion 2016$)	$3.9	$0.1	$14.3	$0.2	$0.1	$14.7	$0.2	$6.6	$0.1	$40.2
CapEx Mainline Compression (Billion 2016$)	$2.8	$2.9	$5.6	$0.0	$6.3	$4.2	$0.3	$2.6	$0.0	$24.8
CapEx Gathering Line Compression (Billion 2016$)	$3.8	$0.0	$10.9	$0.0	$0.0	$8.5	$0.1	$2.6	$0.0	$26.0
Total CapEx (Billion 2016$)	**$16.6**	**$22.5**	**$83.6**	**$0.2**	**$39.4**	**$56.3**	**$1.6**	**$24.3**	**$0.1**	**$244.6**

Escalating Unit Cost, 2018-2035	Central	Midwest	Northeast	Offshore	Southeast	Southwest	Western	Canada	Alaska	Total
Miles of Mainline (1000s)	0.9	2.6	4.0	0.0	3.4	3.8	0.1	0.8	0.0	15.5
Miles of Laterals (1000s)	1.2	0.9	2.9	0.0	2.0	2.1	0.2	1.1	0.0	10.4
Miles of Gathering Line (1000s)	16.8	0.3	9.8	0.3	0.5	44.5	1.3	14.8	0.1	88.3
Compression Transmission (1000 HP)	718	844	1,527	0	1,456	1,502	144	849	0	7,041
Compression Gathering Line (1000 HP)	840	12	3,581	4	4	3,023	25	1,050	2	8,540
CapEx Mainline (Billion 2016$)	$4.2	$19.3	$43.6	$0.0	$31.2	$25.1	$0.2	$7.8	$0.0	$131.4
CapEx Laterals (Billion 2016$)	$3.5	$4.4	$19.9	$0.0	$12.0	$9.1	$0.9	$8.6	$0.0	$58.5
CapEx Gathering Line (Billion 2016$)	$5.3	$0.1	$19.1	$0.3	$0.1	$20.2	$0.3	$9.0	$0.2	$54.7
CapEx Mainline Compression (Billion 2016$)	$4.1	$3.9	$7.6	$0.0	$8.7	$4.7	$0.4	$3.2	$0.0	$32.5
CapEx Gathering Line Compression (Billion 2016$)	$5.5	$0.0	$15.2	$0.0	$0.0	$10.6	$0.2	$3.6	$0.0	$35.2
Total CapEx (Billion 2016$)	**$22.7**	**$27.7**	**$105.4**	**$0.3**	**$52.0**	**$69.8**	**$2.1**	**$32.2**	**$0.2**	**$312.4**

Regional Natural Gas Capital Expenditures in Constant Unit Cost Case, 2018-2035 (Billions of 2016$)



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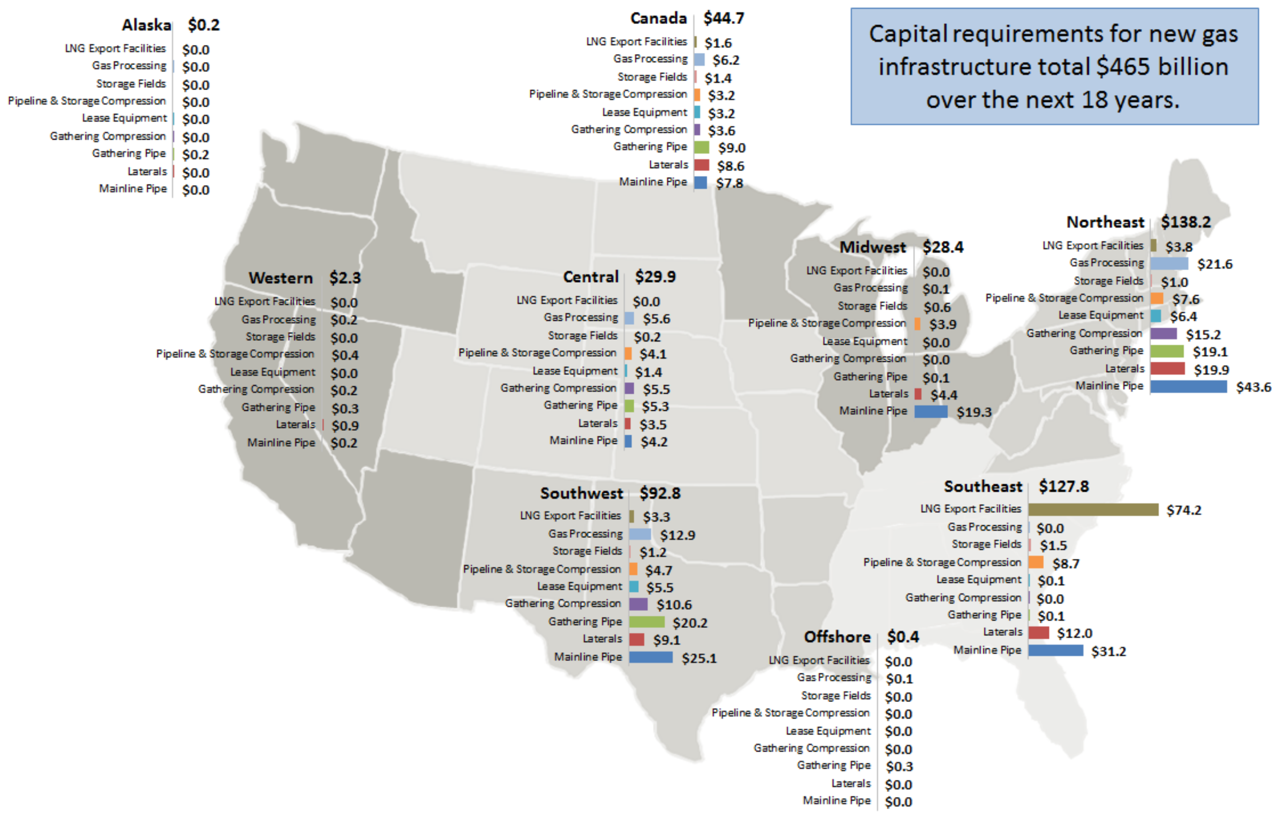
Regional Natural Gas Capital Expenditures in Escalating Unit Cost Case, 2018-2035 (Billions of 2016$)



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Midstream Infrastructure Requirements NGLs

Pipeline Capacity Added for NGL Transport (Million BPD)

- **The study projects 3.6 million BPD of new NGL takeaway capacity between 2018 and 2035.**
- **New capacity distributed across a number of areas.**
  - 45% of new capacity additions in the Southwest driven by production growth from the Permian.
  - The remainder of the growth are spread between the Midwest, Northeast, Central and Canada.

Originating Region	2017	2018	2019-2020	2021-2025	2026-2030	2031-2035	Total 2018-2035	Average Annual 2018-2035
U.S. and Canada	**0.5**	**0.9**	**1.8**	**0.4**	**0.4**	**-**	**3.6**	**0.2**
U.S.	**0.3**	**0.8**	**1.5**	**0.4**	**0.3**	**-**	**3.1**	**0.2**
Canada	**0.1**	**0.1**	**0.3**	**-**	**0.1**	**-**	**0.5**	**0.0**
Central	-	0.0	0.2	-	-	-	0.3	0.0
Midwest	-	0.3	0.2	0.3	-	-	0.8	0.0
Northeast	0.1	0.3	-	-	-	-	0.3	0.0
Offshore	-	-	-	-	-	-	-	-
Southeast	-	-	-	-	-	-	-	-
Southwest	0.3	0.2	1.0	0.1	0.3	-	1.6	0.1
Western	-	-	-	-	-	-	-	-
Alaska	-	-	-	-	-	-	-	-

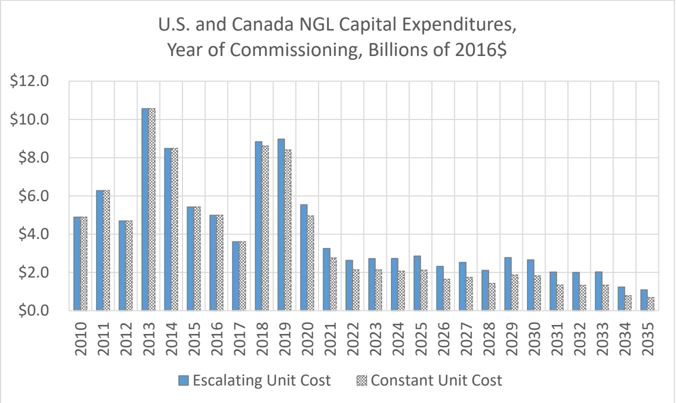
NGLs Metrics and Expenditures

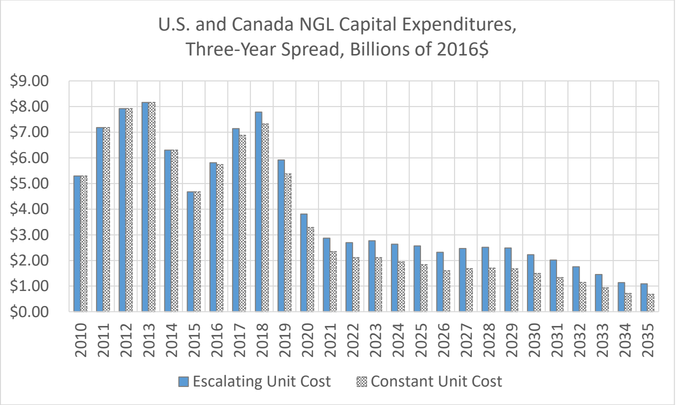
	Both Cases 2018-2035
Miles of Transmission Mainline (1000s)	7.0
Inch-Miles of Transmission Mainline (1000s)	123
Pump for Transmission Mainline (1000 HP)	293
Fractionation Capacity Built (MBOE/d)	3,575
NGL Export Facility Capacity Built (MBOE/d)	1,512

Capital Expenditures (Billions of 2016$)	Constant Unit Cost 2018-2035	Escalating Unit Cost 2018-2035
NGL Transmission Mainline (pipe and pump)	$17.0	$19.5
Pipe	*$15.2*	*$17.6*
Pump	*$1.8*	*$1.9*
NGL Fractionation	$22.6	$29.1
NGL Export Facilities	$7.6	$9.7
Total Capital Expenditures	**$47.1**	**$58.3**

NGL Capital Expenditure Trends

- **Post 2020 buildout is projected to slow significantly due to the robust buildout that occurs through 2020 and due to slowing NGL production growth.**
- **In 2020, incremental Appalachia takeaway capacity is needed in both cases.**
- **Under the Three Year Spend approach, investments in this projects are spread evenly from 2018 resulting in declining trend in NGL infrastructure spending from today's level.**
- **In the subsequent slides, the capital expenditures are based on the "Year of Commissioning" methodology.**





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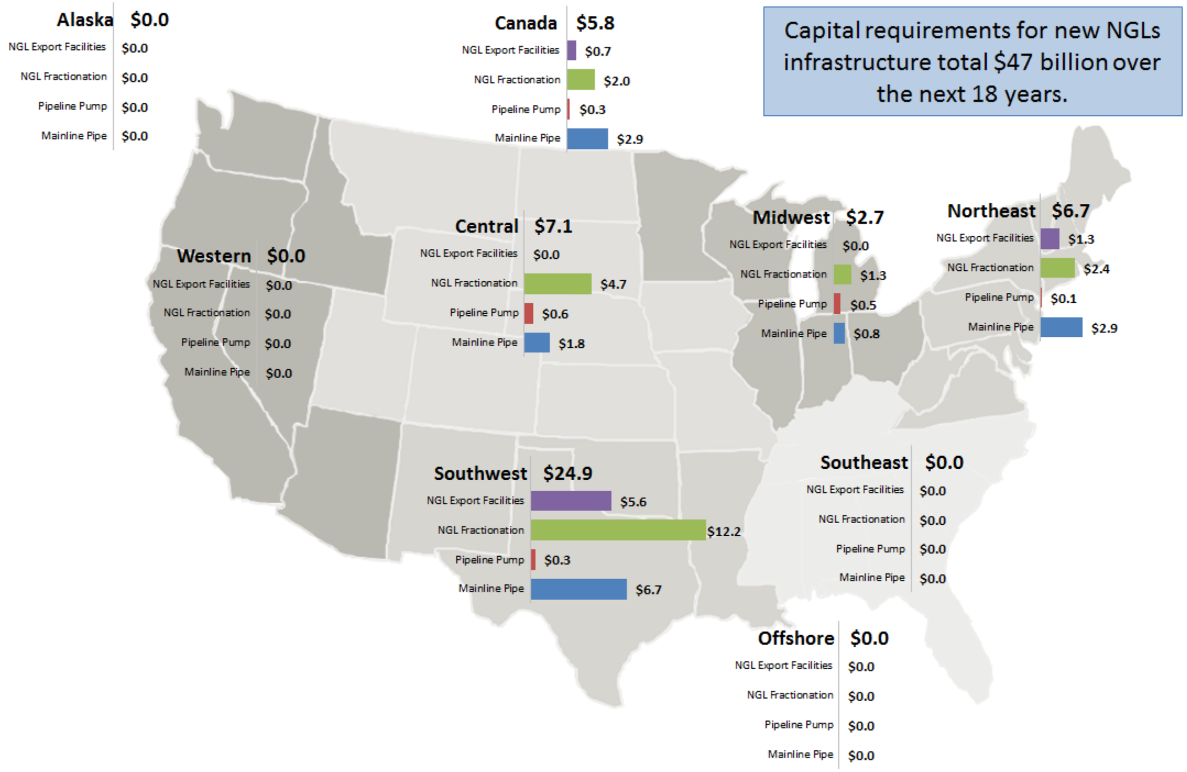
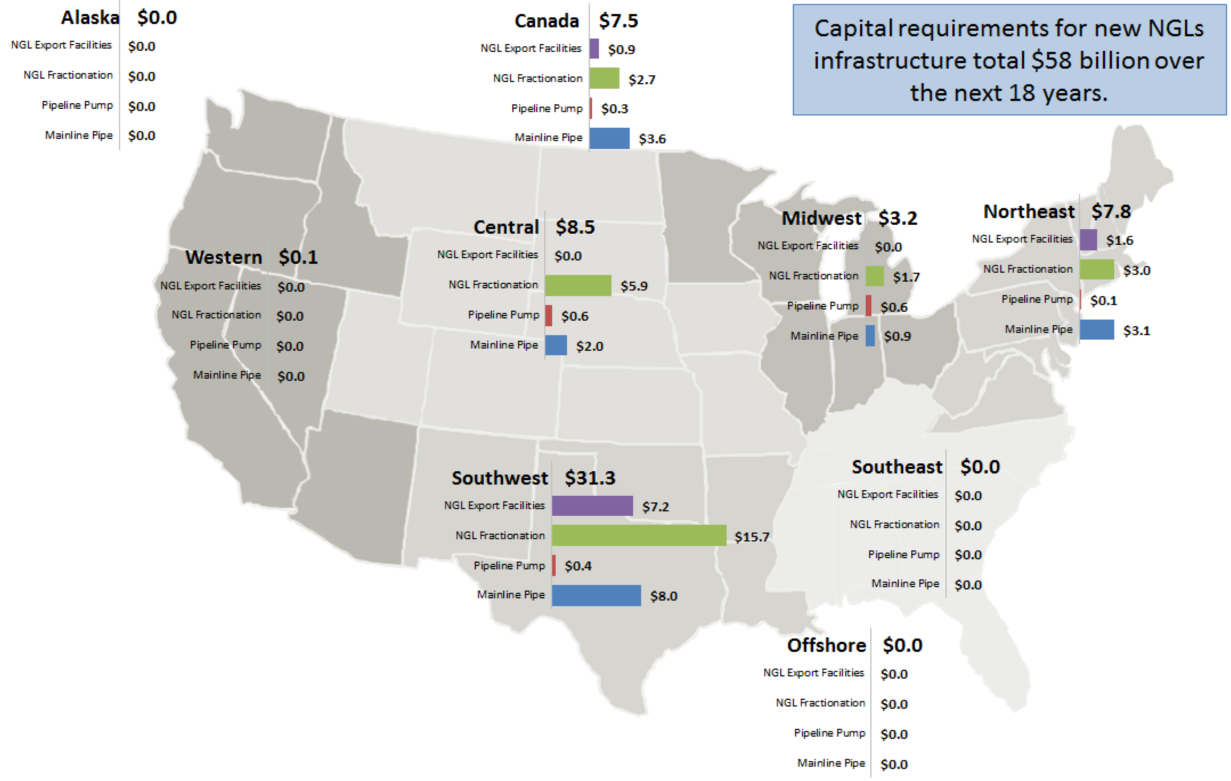
Regional NGLs Capital Expenditures in Constant Unit Cost Case, 2018-2035 (Billions of 2016$)



Regional NGLs Capital Expenditures in Escalating Unit Cost Case, 2018-2035 (Billions of 2016$)



Midstream Infrastructure Requirements
Crude Oil and Lease Condensate

Pipeline Capacity Added for Crude Oil and Condensate Transport (Million BPD)

- **U.S. and Canadian is projected to add at 7.7 million BPD of new crude oil takeaway capacity between 2018 and 2035.**
  - Most of the new capacity is in the Permian, Southwest region.
- **Much of the capacity has already been built and was placed into service in late 2015.**

Originating Region	2017	2018	2019-2020	2021-2025	2026-2030	2031-2035	Total 2018-2035	Average Annual 2018-2035
U.S. and Canada	**1.8**	**0.9**	**1.6**	**3.8**	**1.0**	**0.5**	**7.7**	**0.4**
U.S.	**1.7**	**0.9**	**1.6**	**2.3**	**0.6**	**0.5**	**5.8**	**0.3**
Canada	**0.1**	**-**	**-**	**1.4**	**0.4**	**-**	**1.8**	**0.1**
Central	0.8	-	-	1.0	0.1	-	1.1	0.1
Midwest	0.6	-	-	-	-	-	-	-
Northeast	-	-	-	-	-	-	-	-
Offshore	-	-	-	-	-	-	-	-
Southeast	-	-	-	-	-	-	-	-
Southwest	0.3	0.9	1.6	1.4	0.5	0.5	4.8	0.3
Western	-	-	-	-	-	-	-	-
Alaska	-	-	-	-	-	-	-	-

Crude Oil Metrics

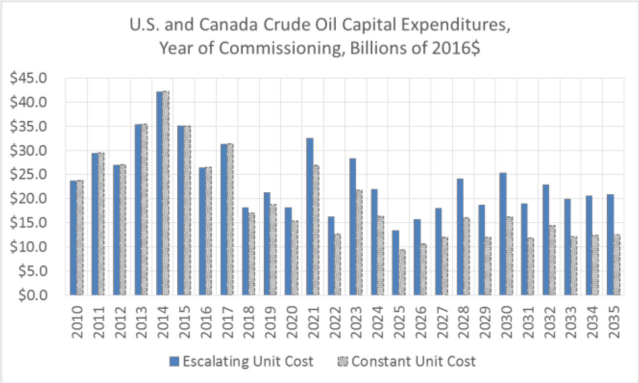
	Both Cases 2018-2035
Oil Well Completions (1000s)	369
Miles of Crude Oil Gathering Line (1000s)	50.6
Miles of Transmission Mainline (1000s)	7.4
Miles of Crude Oil Storage Laterals (1000s)	0.8
Inch-Miles of Crude Oil Gathering Line (1000s)	277
Inch-Miles of Transmission Mainline (1000s)	222
Inch-Miles of Crude Oil Storage Laterals (1000s)	15
Pump for Transmisson Mainline (1000 HP)	1,016
Crude Storage Capacity Built (MMBbl)	139
Number of Crude Storage Tanks Built	27,882
Number of Crude Storage Farms Built	41
Miles of Product Pipeline (1000s)	3.0
Inch-Miles of Product Pipeline (1000s)	40
Pump for Product Pipeline (1000 HP)	528
Offshore Platform Expansion (1000 BOE/D)	6,232

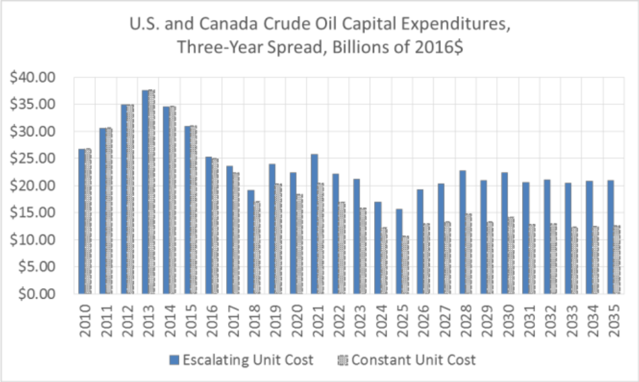
Crude Oil Capital Expenditures

Capital Expenditures (Billions of 2016$)	Constant Unit Cost 2018-2035	Escalating Unit Cost 2018-2035
Crude Oil Gathering Line (pipe only)	$6.1	$8.4
Crude Oil Lease Equipment	$74.7	$104.3
Crude Oil Transmission Mainline (pipe and pump)	$38.0	$47.8
Pipe	*$34.9*	*$44.1*
Pump	*$3.0*	*$3.7*
Crude Oil Storage Laterals	$2.7	$3.2
Crude Oil Storage Tanks	$1.8	$2.1
Product Pipeline (pipe only)	$7.2	$8.5
Product Pipeline Pump	$1.9	$2.4
Crude Oil Rails New Cars	$0.5	$0.5
Offshore Platform	$135.1	$197.6
Total Capital Expenditures	**$267.9**	**$374.8**

Crude Oil Capital Expenditure Trends

- As expected, the peak crude oil infrastructure investment is in 2014 when oil prices were well above $100 per barrel.
- Declining infrastructure developments starting in 2015 are expected to continue in both cases through 2018 due to low oil prices.
- Crude oil price recovery in the two cases, starting in 2021, has a positive impact in infrastructure development thereafter.
- The "Three-Year Spread" shows a smoother near-term spending trend.





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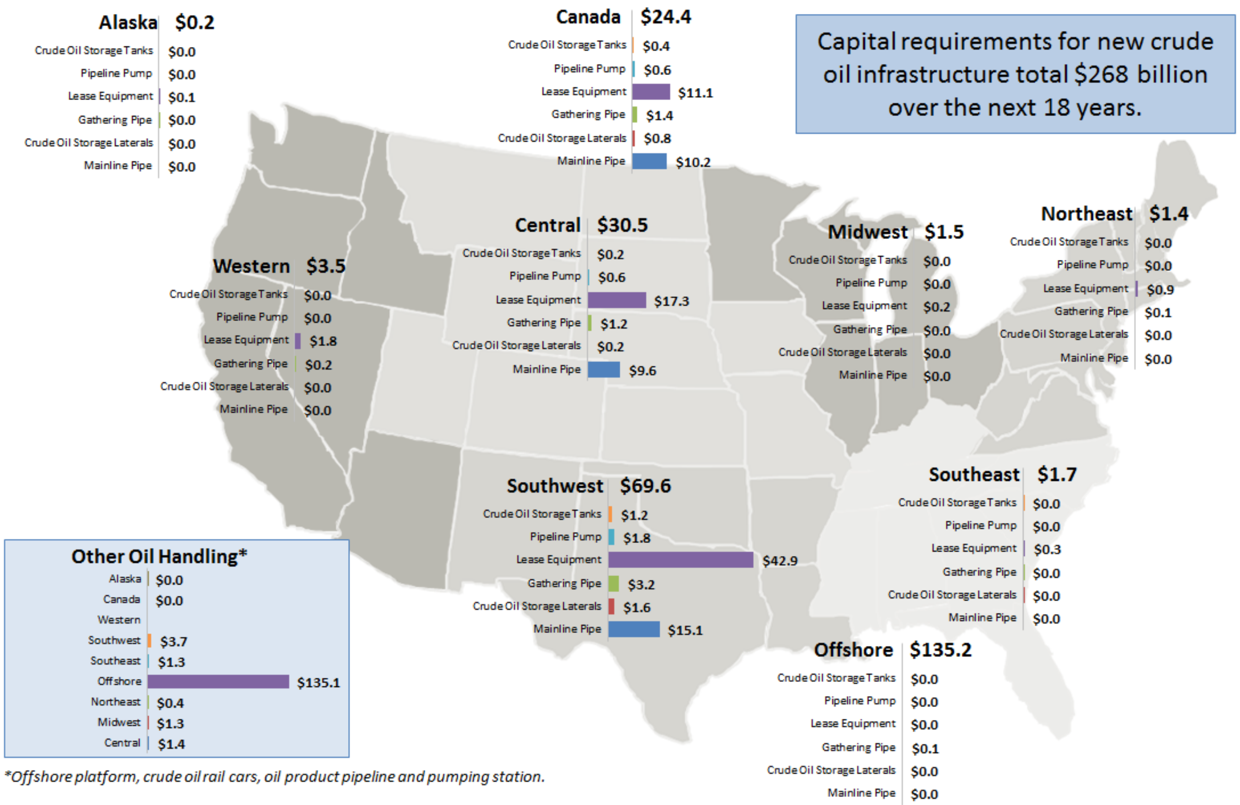
Regional Crude Oil Capital Expenditures in Constant Unit Cost Case, 2018-2035 (Billions of 2016$)



**Offshore platform, crude oil rail cars, oil product pipeline and pumping station.*

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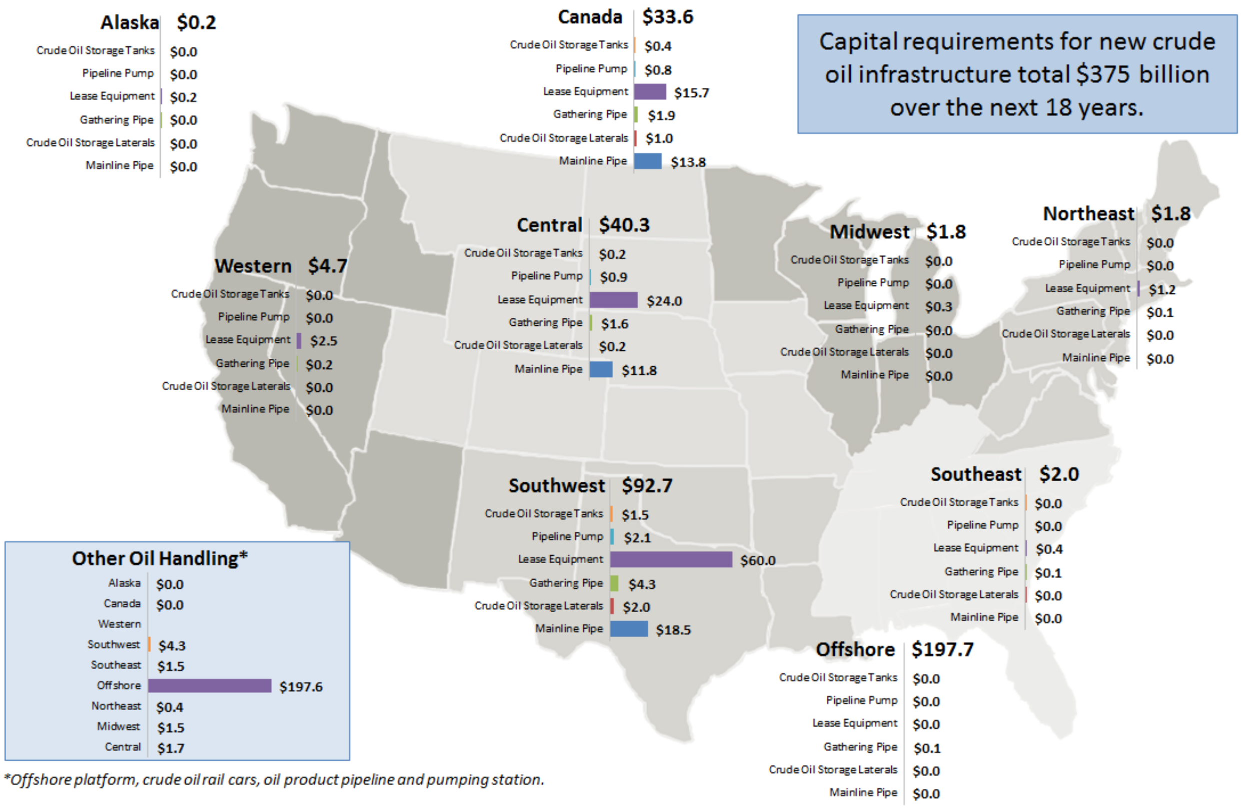
Regional Crude Oil Capital Expenditures in Escalating Unit Cost Case, 2018-2035 (Billions of 2016$)



*Offshore platform, crude oil rail cars, oil product pipeline and pumping station.

Economic Impact Methodology Assumptions

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IMPLAN Modeling

- **Analysis relies on IMPLAN modeling, a proprietary model maintained by the Minnesota IMPLAN Group (www.implan.com).**
  - IMPLAN is a widely used and effective regional economic analysis model that uses average expenditure data from industries.
  - IMPLAN uses multipliers to trace and calculate the flow of dollars from the industries that originate the economic activity to supplier industries that generate additional activity. These multipliers are thus coefficients that describe the response of the economy to a stimulus (a change in demand or production).
- **Three types of impacts used in IMPLAN:**
  - Direct – represents the economic impacts (e.g., employment or output changes) due to the direct investments, such as payments to companies in the relevant industries for the asset category in this study.
  - Indirect – represents the economic impacts due to the industry inter-linkages caused by the iteration of industries purchasing from industries, brought about by the changes in final demands (e.g., when pipeline manufacturer purchases steel from another company).
  - Induced – represents the economic impacts on all local industries due to consumers' consumption expenditures arising from the new household incomes that are generated by the direct and indirect effects of the final demand changes (e.g., a worker purchases new clothing or purchases food in restaurants).

Sector Allocations of Investment Expenditures (Direct Output) for National-Level Economic Impact Analysis

Industry Sector	Gathering Line	Lease Equipment	Natural Gas Processing	Pipeline	Compressors	Pumps
Oil, Natural Gas & Other Mining	5.8%	0.0%	0.2%	5.8%	5.3%	5.3%
Construction	36.2%	39.7%	28.0%	36.2%	30.1%	27.6%
Manufacturing	29.4%	22.2%	44.9%	29.4%	37.7%	40.2%
Wholesale and retail trade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transportation	2.1%	2.1%	1.5%	2.1%	2.0%	2.0%
Services & All Other	26.5%	36.0%	25.4%	26.5%	24.9%	24.9%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Industry Sector	Underground Natural Gas Storage	LNG Plant	NGL Fractionation Plant	NGL Export Facility	Crude Oil Storage Tanks	Other Oil Handling	All Infrastructures Analyzed
Oil, Natural Gas & Other Mining	69.9%	0.3%	0.2%	0.3%	5.3%	0.3%	8.2%
Construction	4.5%	28.3%	28.0%	28.3%	31.3%	28.3%	28.9%
Manufacturing	13.6%	32.9%	44.9%	32.9%	36.5%	32.9%	33.1%
Wholesale and retail trade	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transportation	8.1%	2.1%	1.5%	2.1%	2.0%	2.1%	2.5%
Services & All Other	3.7%	36.3%	25.4%	36.3%	24.9%	36.3%	27.3%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

National Tax Rates on Gross Domestic Product (GDP)

	Federal Tax Rate on GDP*	Weighted Average State/Provincial and Local Tax Rate on GDP	Total
U.S.			
2017	18.9%	15.3%	34.3%
2020	18.9%	15.6%	35.4%
2025	19.6%	15.8%	36.2%
2030	20.1%	16.0%	36.9%
2035	20.6%	16.2%	37.6%
Canada			
2017-2035	12.2%	19.6%	31.8%

**U.S. Federal Source of Revenue as Share of GDP, February 15, 2017, Tax Policy Center, https://www.taxpolicycenter.org/statistics/source-revenue-share-gdp, adjusted for lower corporate tax rate from 2018.*

Distribution of National-Level Economic Impacts Across Regions using Region-Level Allocators

- **National-level economic impact results, by individual infrastructure category, are distributed across regions based on region-level "allocators".**
- **National "direct" impacts (e.g. direct value added) are distributed to regions and states based on expenditure allocators.**
  - Expenditure allocators are calculated from infrastructure investment expenditures. In this analysis, investment expenditures for the U.S. Offshore region is assumed to be spent in the Southwest region.
- **National "indirect" impacts (e.g. indirect value added) are distributed to regions based on a combination of expenditure allocators (60% weight) and Indirect Industrial Jobs allocators (40% weight).**
- **National "induced" impacts are distributed to regions based on a combination of the "Direct & Indirect Value Added" allocators (40% weight) and State Personal Income in 2013 (60% weight).**
  - "Direct & Indirect Value Added" allocators are calculated from the sum of regional direct and the indirect Value Added, as discussed above.

Region-Level Allocators

Region	Indirect Industrial Jobs[a]	State Personal Income 2015[b]
Central	6.6%	7.7%
Midwest	26.8%	15.9%
Northeast	25.7%	27.5%
Southeast	16.5%	17.4%
Southwest	12.7%	11.7%
Western	11.6%	19.6%
Alaska	0.0%	0.3%
Total	**100.0%**	**100.0%**

[a]Weighted average of industries that support construction and equipping industrial activities based on IMPLAN input-output model and U.S. Bureau of Labor statistics data.
[b]State personal income FY 2015 from Tax Policy Center (Urban Institute and Brookings Institution). "State and Local General Revenue as a%age of Personal Income FY 2015." Tax Policy Center, 15 December, 2017: Washington, DC.

Distribution of U.S. Tax Revenues Across Regions Using State/Local Tax Allocators

- National-level tax revenues (federal and state/provincial/ local) are calculated from Total Value Added and tax rates on GDP (federal and state/provincial/local).
- For the U.S., total state and local tax revenues are distributed across the regions based on region-level State/Local Tax allocators.

U.S. State/Local Tax Allocators

Region	State and Local Tax Rate on GDP FY 2015*
Central	15.6%
Midwest	15.2%
Northeast	15.0%
Southeast	14.7%
Southwest	14.6%
Western	15.0%
Alaska	33.9%

*State and Local General Revenue as a%age of Personal Income FY 2015, Urban Institute and Brookings Institution, http://www.taxpolicycenter.org/taxfacts/displayafact.cfm?Docid=510

Results of Economic Impact Analysis Using IMPLAN

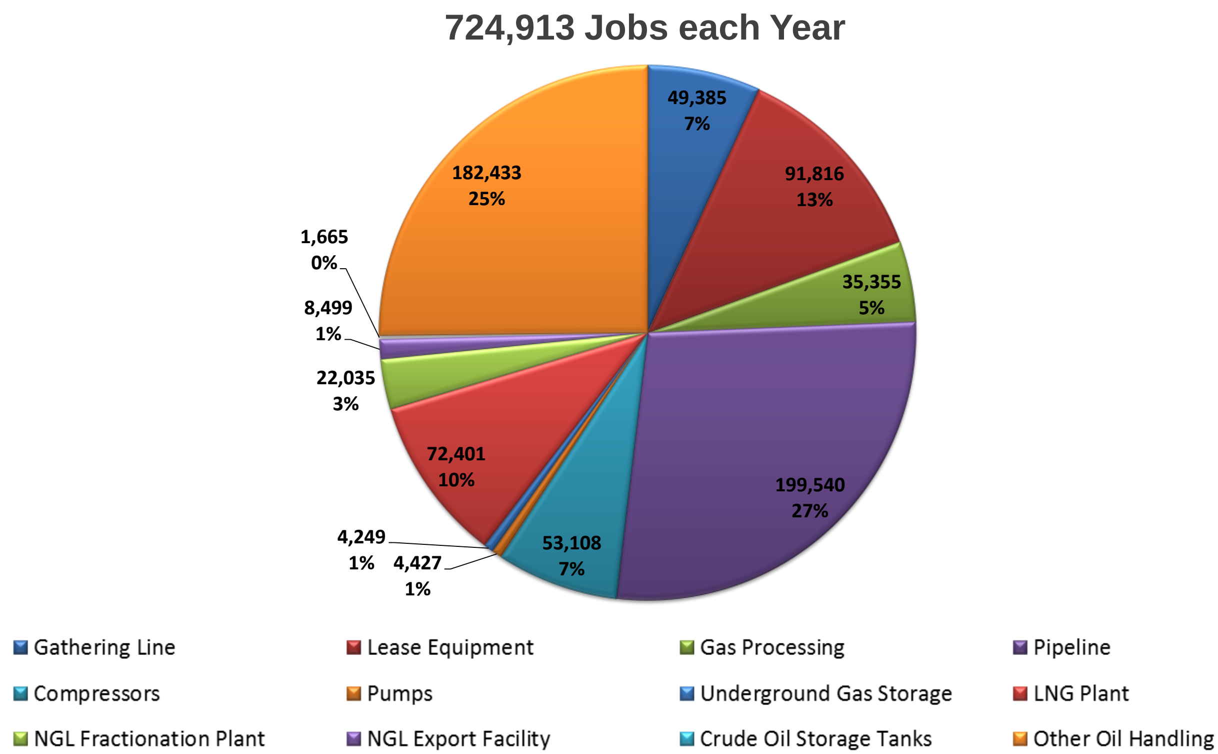
The INGAA Foundation Inc.

U.S. and Canada: Economic Impacts, 2018-2035

Impact Type	Employment (Jobs each Year)	Annual Wages and Benefits (2016$ Per Job)	Labor Income (Billions of 2016$)	Value Added (Billions of 2016$)	State/Provincial and Local Tax Revenues (Billions of 2016$)	Federal Tax Revenues (Billions of 2016$)
Direct	242,216	$77,558	$338.1	$413.4		
Indirect	189,524	$67,021	$228.6	$366.6		
Induced	293,173	$51,107	$269.7	$482.2		
Total	**724,913**	**$64,106**	**$836.5**	**$1,262.2**	**$204.0**	**$237.7**

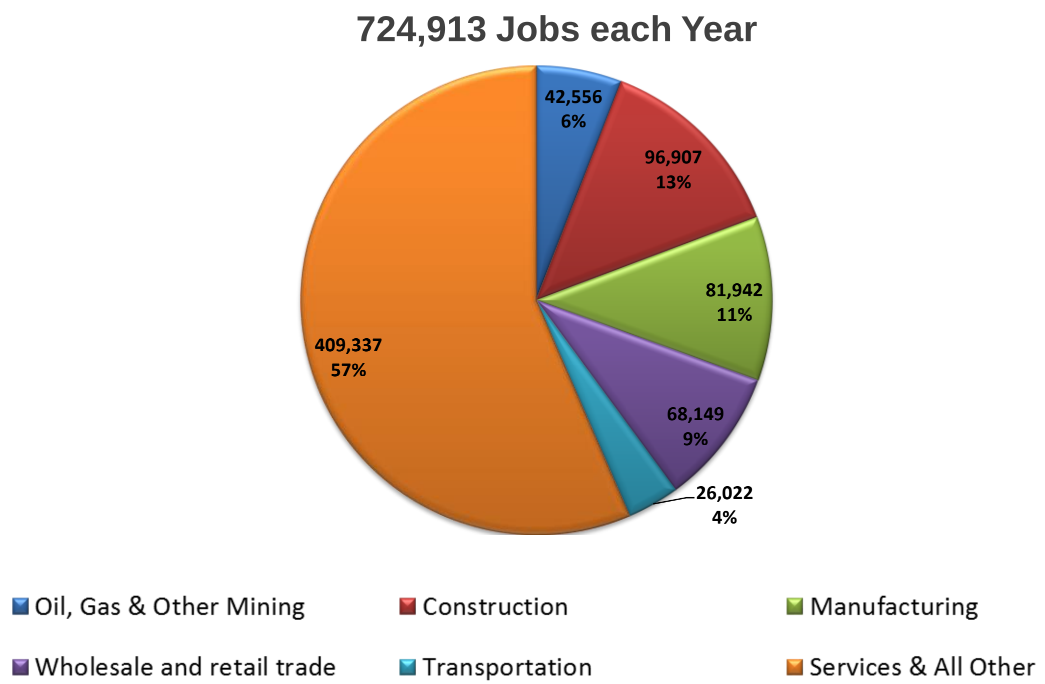
The INGAA Foundation Inc.

U.S. and Canada Total Employment by Asset Category, 2018-2035 (Jobs each Year)



The INGAA Foundation Inc.

U.S. and Canada Total Employment by Industry Sector, 2015-2035 (Jobs each Year)



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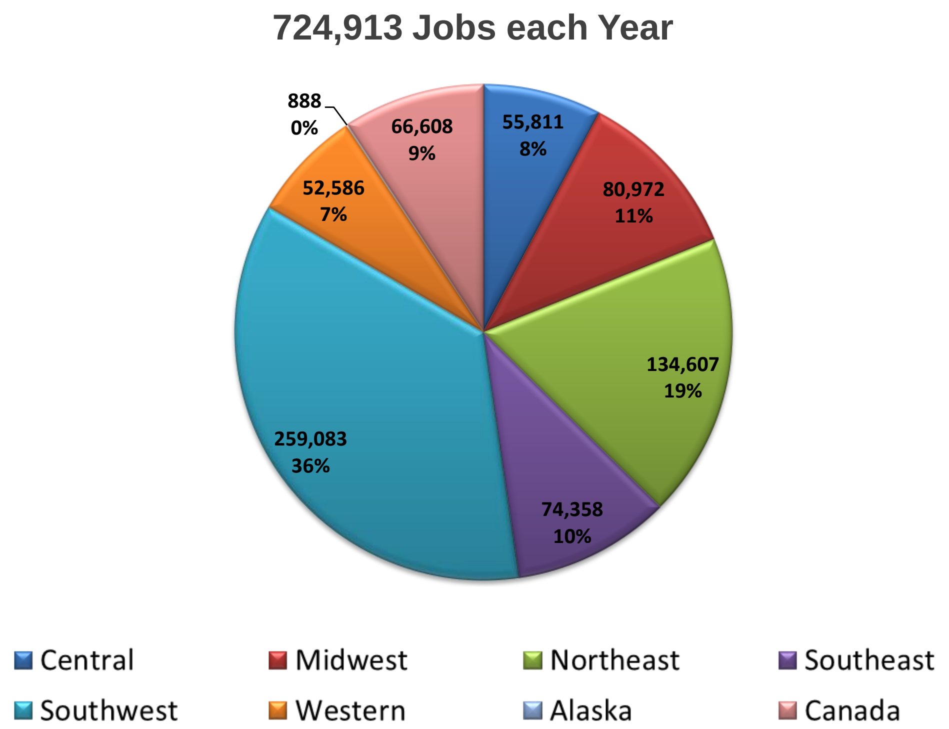
Total Employment by Region, 2018-2035 (Jobs each Year)



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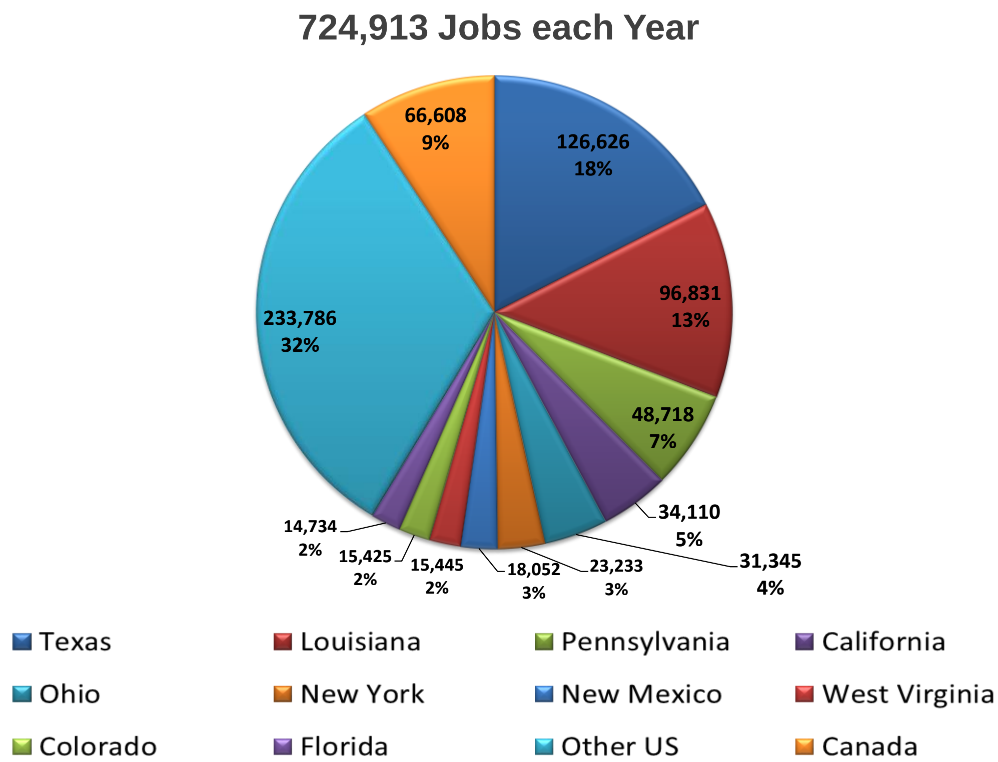
Total Employment by State, 2018-2035 (Jobs each Year)



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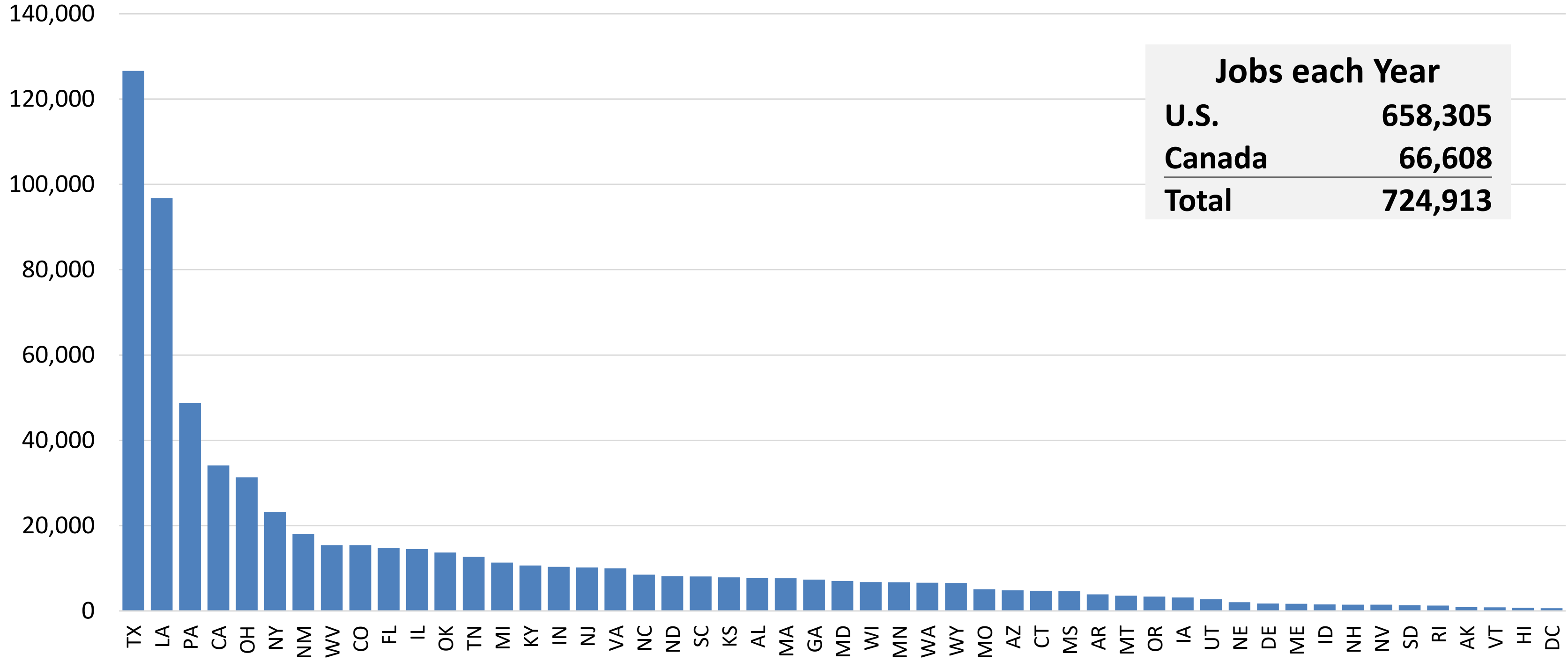
Total Employment by State 2018-2035 (Jobs each Year)



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Glossary

Units

Bbl	Barrels
Bcf	Billion Cubic Feet
Bcfd	Billion Cubic Feet per Day
BOE	Barrel of Oil Equivalent
BOE/d	Barrel of Oil Equivalent per Day
BPD	Barrel per Day
Btu	British Thermal Unit
GW	Gigawatts
HP	Horsepower
MBOE/d	Thousand Barrel of Oil Equivalent per Day
MMBbl	Million Barrels
MMBpd	Million Barrels per Day
MMBtu	Million Btu
MMcfd	Million Cubic Feet per Day
Tcf	Trillion Cubic Feet

Acronyms

DPR	ICF's Detailed Production Report
EIA	Energy Information Administration
GDP	Gross Domestic Product
GMM	ICF's Natural Gas Market Model
GTL	Natural Gas-to-Liquids
LACT	Lease Automatic Custody Transfer
LNG	Liquefied Natural Gas
NGL	Natural Gas Liquid
NWT	Northwest Territories, Canada
R/C	Residential/Commercial Sector

ICF