The INGAA Foundation, Inc.

North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance

An INGAA Foundation Report, Prepared by ICF International

Executive Summary
March 18, 2014

Background

Since the last INGAA Foundation midstream infrastructure study completed in 2011,[1] development of North American unconventional natural gas and crude oil supplies, particularly supplies from shale formations, has continued at an unprecedented pace. With the ever-changing supply picture, midstream infrastructure development is crucial for efficient delivery of growing supplies to markets. Sufficient infrastructure goes hand in hand with well-functioning markets. Insufficient infrastructure can constrain market growth and strand supplies, potentially leading to increased price volatility and reduced economic activity.

Natural gas use in North America has increased over the past decade, particularly in the power-generation sector where natural gas has become a fuel of choice. In addition, there has been a resurgence of gas use in industrial applications at the relatively low gas prices that have prevailed during the past few years, while growing production of natural gas liquids (NGL) has stimulated renewed interest in petrochemicals production where ethane and propane are key feedstocks. Meanwhile, growing oil production from unconventional sources has created opportunities for North American refineries to take advantage of crude supplies from various sources.

Midstream infrastructure investments have been keeping pace with supply and market changes. Producers of natural gas, crude oil, and NGL are driving investments in infrastructure by committing to the pipeline capacity needed to ensure delivery of new supplies to markets. Because of these dynamics, the INGAA Foundation felt compelled to update, further refine, and expand its infrastructure study. This new study builds on the prior INGAA Foundation study and considers how the shifting market dynamics

[1] http://www.ingaa.org/Foundation/Foundation-Reports/Studies/14904/14889.aspx

experienced in recent years have altered infrastructure needs and continue to create opportunities and challenges for midstream infrastructure development.

Introduction

The objective of this new study is to inform industry, policymakers, and stakeholders about the new dynamics of North America's energy markets and the infrastructure that will be needed to ensure that consumers benefit from the abundance of natural gas, crude oil, and NGL across the United States and Canada. This is particularly relevant as policymakers seek to promote job growth and economic development, protect the environment, increase energy security, and reduce the trade deficit.

This study assesses midstream infrastructure needs through 2035 and includes an extensive update of natural gas, NGL, and oil production trends based on projections of drilling activity and consideration of the increasing recoverable resource base and prevailing market conditions.[2] This study expands on the scope of the 2011 study to assess the changing market dynamics and the growing importance of crude oil and NGL production. This study also re-assesses the levels of investment in gas gathering systems; processing plants; gas storage fields; and oil, gas, and NGL transmission lines.[3] It also considers investments that were not considered in the 2011 study, including investments in compression for gas gathering lines, crude oil gathering lines, crude oil storage terminals, NGL fractionation facilities, NGL export facilities, oil and gas lease equipment, and liquefied natural gas (LNG) export facilities. These facilities account for a substantial portion of the total midstream investments identified in this study.

Study results are driven by projected increases in U.S. and Canadian crude oil and natural gas supplies, as well as North American market growth, particularly in the power and industrial sectors. Natural gas imports in the form of LNG, which in previous projections were viewed as a marginal supply source, have been displaced by even more robust domestic gas and NGL production growth, and LNG export capability has been introduced in this updated study. The study projects that NGL use will grow, particularly in petrochemical applications. It also projects new oil supplies will flow to refineries through new or repurposed pipeline infrastructure, displacing foreign imports of oil over time.

A Brief Comparison with the 2011 Study

Since the prior study was completed in 2011, hydrocarbon development from shale formations has continued at a rapid pace. Development of resources from areas like the Marcellus, Haynesville, and Barnett shale plays has continued, and some of the areas, most notably the Marcellus and Bakken shale, have continued to surpass expectations. In addition, new areas, like the Eagle Ford and Niobrara shale,

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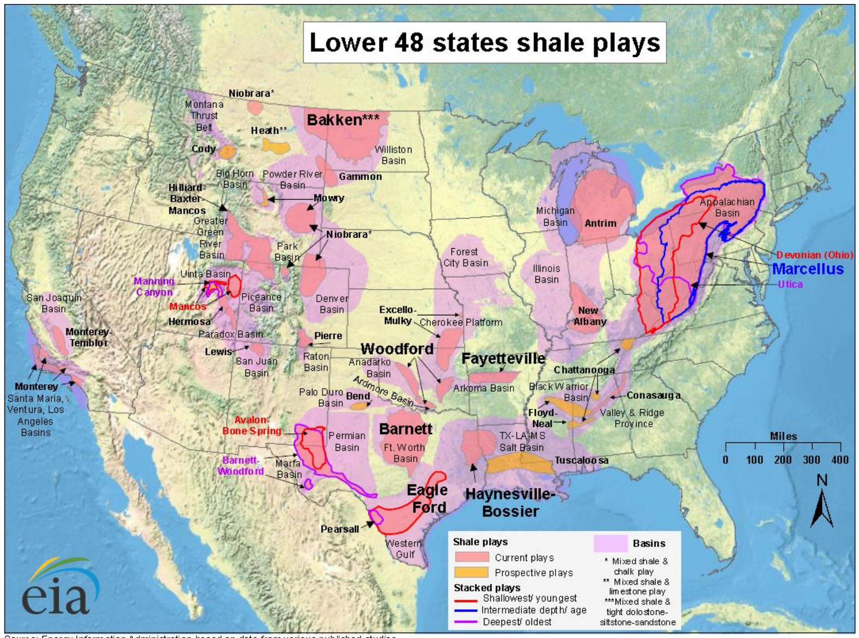
[2] This study assesses the amount of new midstream infrastructure needed and the costs associated with its development over time. It does not assess infrastructure replacement and its costs, nor does it assess the costs of operations and maintenance (O&M) of the infrastructure.

[3] While this study considers investment in crude oil transport, it does not consider investment in the transport of refined products because they are transported from refineries, and those lines are not considered to be part of the midstream space.

have joined the mix of formations under rapid development. The result is that natural gas resource development has continued unabated, and NGL and oil development has also surged in recent years.



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

With the rapid pace of shale resource development, midstream infrastructure development has continued to be robust, and current expectations are that the next decade holds much promise for ongoing midstream development. Areas with relatively low gas resource costs, such as the Marcellus shale play, are likely to continue to spur supply and midstream infrastructure development. So, the current study, like the prior study, projects significant development of natural gas infrastructure to accommodate the rapidly growing gas supplies from shale. Thus, much new gas gathering and pipeline infrastructure will be needed well into the future. While the pipeline projects included in this study typically are shorter distance projects than those foreseen in the prior study, the costs and levels of investment in them is about the same as in the prior study because pipeline costs have risen since the earlier study.

In addition to the significant natural gas development that is foreseen, the projected levels of oil and NGL midstream infrastructure development are greater than in the prior study. This, in large part, is due to the increased expectations for oil and liquids development that are being spurred by relatively high oil prices. In addition, a number of newer oil- and liquids-rich plays, such as the Eagle Ford and Niobrara, have entered the development fray, and are adding to the incremental oil and liquids development over time. The enhanced oil and liquids development has created ample opportunity for new midstream infrastructure and significantly increased the level of investment in oil and liquids transport versus estimates from the prior study.

This new study includes some investments that were not considered in the prior study. To formulate a more complete accounting for midstream infrastructure development, this new study includes substantial investments in lease equipment. For oil wells, this equipment includes pumps, valves and manifolds, flowlines and connections, stock tanks, separators, and heater-treaters. For gas wells, the equipment considered includes pumps, flowlines and connections, and dehydrators. In addition, this new study includes investments in liquids fractionation facilities, LNG export facilities, oil gathering lines, and compression and pumps for gathering systems, all of which were not considered in the prior study. These additional components make a direct comparison of this new study with the prior study difficult because they increase the level of investment significantly. These components, which had not been previously considered, account for roughly half of the total expenditures projected in this study.

In summary:

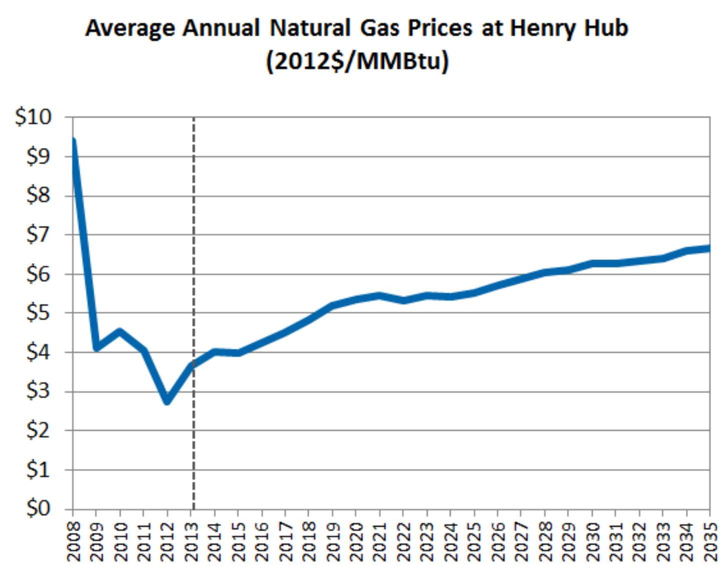
- This new study includes similar levels of gas infrastructure development to those projected in the prior study. While gas pipeline projects included in this study typically are shorter than those considered in the prior study, the level of investment is similar because pipeline costs have risen since the prior study. This new study considers the increased costs.

- This new study includes greater levels of oil and liquids production. Increased levels of oil and liquids production motivate additional development of midstream infrastructure.

- This new study includes investments in lease equipment, fractionators, LNG export terminals, oil gathering lines, and compressors and pumps for gathering systems—all components that were not considered in the prior study.

Summary of the Reference Case Outlook

The December 2013 ICF reference case, provided by ICF's ICForecast Subscription Service, is the reference case for this study. The case projects that Henry Hub gas prices will average around $6 per million British thermal units (MMBtu) in the longer term, at an assumed crude oil price of $100 per barrel in real terms.[4] A $5 to $6 per MMBtu gas price is sufficiently high to encourage substantial gas supply development, but not high enough to limit market growth. In the reference case gas price scenario, both gas supply and demand are expected to increase significantly over time. This growth, when combined with regional shifts in supply and demand over time, creates a positive environment for midstream infrastructure development.



[4] The crude oil price referenced here is the average refiner's acquisition cost of crude, which represents the average price of crude oil delivered to refineries across the United States.

Estimates and Assumptions Driving Results

Assumptions for oil, natural gas, and natural gas liquids use: This reference case assumes that the U.S. population will grow at an average rate of about 1 percent per year, while U.S. gross domestic product (GDP) increases 2.0 percent in 2013, 2.8 percent in 2014, and 2.6 percent from 2015 onward. Electric load is assumed to grow at 1.5 percent per year from 2013 to 2020, and then at 1.1 percent per year from 2021 onward. The reference case assumes that industrial production growth averages 2.3 percent per year throughout the projection, consistent with the GDP assumption. It also assumes that weather conditions are consistent with the average weather over the past 20 years, and that ethylene, polypropylene, and propane export facilities are built as per recently announced plans. The reference case further assumes that crude imports are permitted to decline, or be de-contracted, as local crude supplies grow, but that crude exports remain prohibited in the future.

Resource and supply estimates: Current U.S. and Canadian gas production originates from more than 300 trillion cubic feet (Tcf) of proven gas reserves. The North American natural gas resource base is estimated to total 4,000 Tcf when adding unproved resources to discovered-but-undeveloped gas resources. This resource base can supply U.S. and Canadian gas markets for almost 150 years at current consumption levels. The study assumes that gas supply development will continue at recently observed levels, and that there will be no new significant production restrictions (e.g., hydraulic fracturing regulations that impede supply development). The supply outlook presented below is generally a market-balancing view. In other words, the abundant resource base is balanced with demand to determine the volume that is produced or supplied. Gas production projections from the model are cross-checked with a vintage production analysis using ICF's Detailed Production Report (DPR). Crude oil and NGL production projections are computed in ICF's DPR as well. ICF's DPR considers the number of wells, well recoveries, and representative decline curves to estimate production trends for almost 60 different supply areas throughout the United States and Canada.

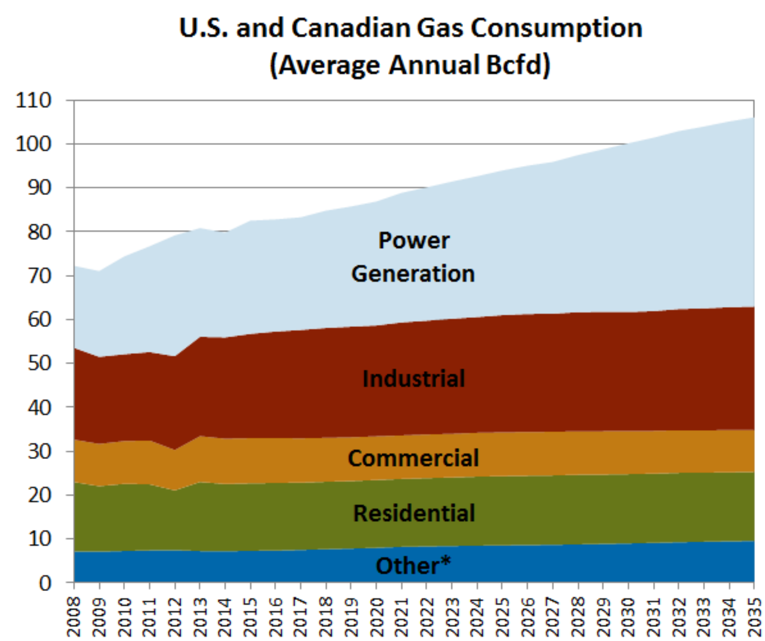
Construction of new pipelines and other midstream infrastructure assumed in the projection: Near-term midstream infrastructure development includes projects that are currently under construction or sufficiently advanced in the development process. Unplanned projects are included in the projection when the market signals the need for new capacity. It is assumed that these projects are built without significant delays in permitting and construction in order to balance supply development with market growth. In this report, lease equipment, gathering, processing, and fractionation infrastructure projects are included for natural gas, NGL, and crude oil development. These types of projects are built as needed to support supply development. This infrastructure typically is financed as part of upstream project development, but is included in this midstream infrastructure analysis because many of the investments are funded by field services operations provided by companies that are active in the midstream space. Arctic projects (specifically the Alaska and Mackenzie Valley gas pipelines) are not included in the projection because market prices do not support the development of such projects. In this study, net LNG exports occur from both Western Canada and the United States.

Pipeline cost assumptions: Pipeline cost assumptions have been derived by considering *Oil and Gas Journal*'s Annual Pipeline Economics Special Report, U.S. Pipeline Economics Study, 2013 (hereinafter referred to as "the OGJ report"). Based on the survey in the OGJ report, pipeline costs recently have risen to $155,000 per inch-mile from $94,000 per inch-mile in the prior study, and this study, like the prior study, assumes that the costs will remain constant at the most recent value in real terms over the entire projection period. Regionally, costs vary significantly, with costs being considerably higher in the northeastern states and significantly lower in the southwestern states. Costs also are assumed to vary by grade of pipe, so the smaller diameter pipes used mostly in gathering systems have lower cost factors applied. The costs for pipes that are less than 12 inches in diameter are assumed to range from $20,000 to $70,000 per inch-mile.

The OGJ report estimates average compression costs at $2,600 per horsepower, and this study assumes that compression costs will remain at that level in real terms throughout the projection. As was the case for pipe costs, compression costs vary by region, with costs being highest in the northeastern states and lowest in the southwestern states. The pipeline and compression cost factors assumed in this study are considerably higher than the factors applied in the prior study because the costs, on a unit basis, have increased in recent years. A number of factors are contributing to the higher costs, most notably increasing labor and materials costs.

Natural Gas Demand Results

Natural gas consumption in the United States and Canada is projected to increase by an average of 1.2 percent per year through 2035. Total natural gas use across all sectors is projected to rise to an average of roughly 106 billion cubic feet per day (Bcfd) in 2035 from around 80 Bcfd in 2013. In addition, the ICF reference case projects about 9 Bcfd of LNG exports from the United States and Canada, and roughly 5 Bcfd of pipeline exports to Mexico from the United States in 2035. So, total consumption for natural gas, including gas leaving the United States and Canada, rises to an average of about 120 Bcfd in 2035, a 1.8 percent per year increase. About 75 percent of the incremental demand growth within the United States and Canada occurs in the power sector, which is projected to account for more than one-third of total gas demand by 2035. Today, the power sector accounts for about 30 percent of gas use. Most of the rest of the demand growth occurs in the industrial sector, where gas is used incrementally in petrochemical and refining operations.



*Other includes lease, plant, and pipeline fuel gas use.

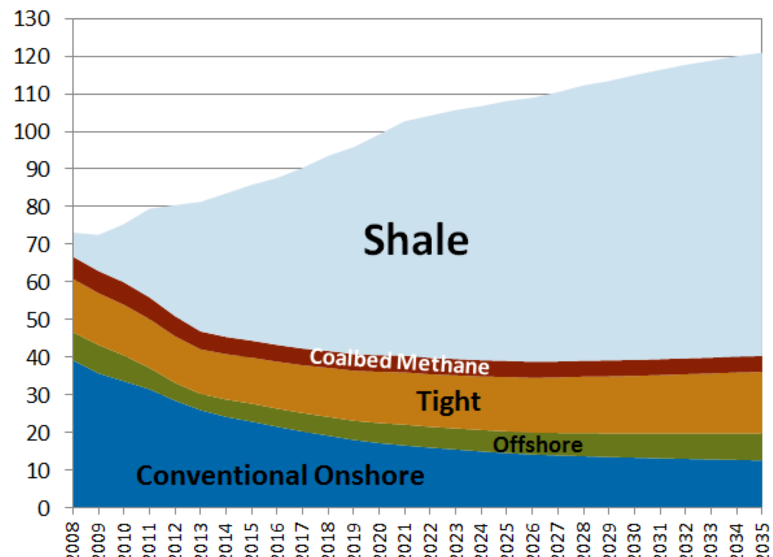
Regions with the largest increase in gas use are the southeastern United States, followed closely by the northeastern and southwestern United States. All areas exhibit significant power-generation demand growth. Canada also sees large demand growth, not only related to power generation but also related to the natural gas required for oil sands production and development. When LNG exports are considered as part of the total, the southwestern United States is the area that experiences the largest increase in gas disposition because the majority of LNG exports occur from that region.

Study Regions

Natural Gas, NGL, and Crude Oil Production

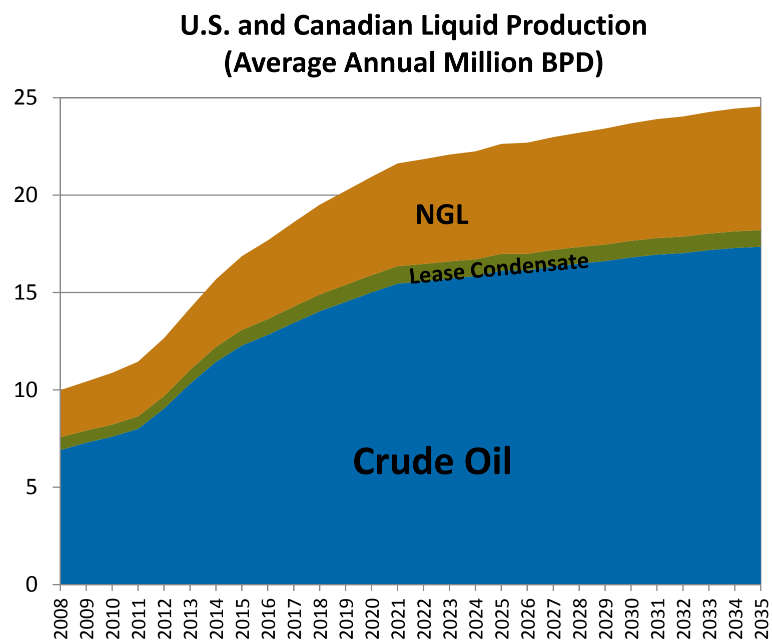
U.S. and Canadian natural gas production is projected to grow from an average of 83 Bcfd in 2014 to an average of more than 120 Bcfd in 2035, adequate to meet projected gas market needs in 2035. Unconventional natural gas supplies account for all of the incremental supply as production from conventional areas declines. Unconventional supplies (mostly shale plays) will account for approximately two-thirds of the total gas supply mix in 2035. Shale gas production is expected to exceed half of the total production over the next few years.

U.S. and Canadian Natural Gas Production (Average Annual Bcfd)



U.S. and Canadian shale plays are among the world's fastest growing production areas. The Barnett shale play has been under development for more than a decade, while development of the Fayetteville, Woodford, Marcellus, Haynesville, Eagle Ford, Bakken, Niobrara, Monterrey, Horn River, and other shale resources began more recently but promise to contribute to the nation's growing gas supply. Several of these shale plays include areas with very large hydrocarbon production potential, such as the gas-rich Marcellus and Haynesville fields. Other shale plays, like the Bakken, Eagle Ford, and Niobrara, are more liquids (NGL and oil) prone. The Marcellus shale play is projected to display the greatest growth in natural gas supply, more than doubling its current production level of around 13 Bcfd by 2035. The strength of the shale plays was evident during the recession of 2008-2009, when robust development continued despite relatively low economic activity and poor market conditions.

Like gas production, petroleum liquids production is projected to grow in the foreseeable future. The reference case for this study projects that U.S. and Canadian crude oil and condensate production will grow from a recent level of roughly 10 million barrels per day (BPD) to 18.2. More than half of the growth is from unconventional (often referred to as "tight") oil supplies, which include production from the Bakken, Niobrara, Eagle Ford, and Cline plays. In addition, the oil sands in Western Canada account for a significant portion of the growth in oil production.



Like oil and gas production, NGL production will grow significantly over time. In this study's reference case, NGL production roughly doubles by 2025, rising to about 6 million BPD. The growth comes from a variety of shale plays, most notably the Eagle Ford, Marcellus, and Western Canada plays. The growth of liquids production hinges on the development of transport capability and markets for the liquids. Absent such development, NGL production would be stranded in a number of key areas, posing not only challenges for liquids development, but for gas development as well. Natural gas pipelines require that gas transport takes place within certain tolerances for BTU content. Thus, lack of adequate infrastructure for processing and transport of NGL eventually leads to stranded gas supplies because the gas lines will be unable to receive and transport the liquids-laden stream if they are to remain within the required tolerances.

Transportation Changes and Infrastructure Requirements

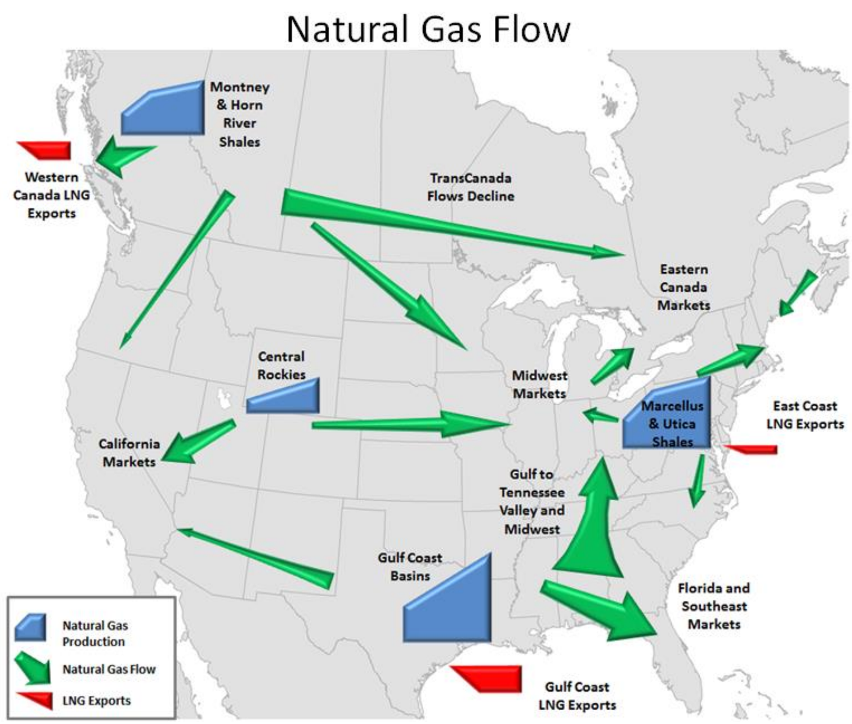
New infrastructure will be required to move hydrocarbons from regions where production is expected to grow to locations where the hydrocarbons are used. Not all areas will require significant new pipeline infrastructure, but many areas (even those that have a large amount of existing pipeline capacity) may require investment in new capacity to connect new supplies to markets. In analogous cases to date, oil and gas producers and marketers have been the principal shippers on new pipelines. These "anchor shippers" have been willing to commit to long-term contracts for transportation services that provide the financial basis for pipeline companies to pursue projects. Going forward, producers will likely continue to be motivated to ensure that the capacity exists to move supplies via pipelines. Producers have learned from past experience that the consequences of insufficient infrastructure for gas transport are severe, and that the cost of pipeline transport is a relatively small cost compared with the revenues lost as a result of price reductions or well shut-ins that occur when transport from producing areas to liquid pricing points is constrained.

ICF's Gas Market Model (GMM) and Oil and Liquids Transport Models (OLTMs) have been applied to study how transport dynamics are likely to change as supply grows and markets change in the reference case. The stylistic maps presented on the following pages depict the changing flow patterns observed in the models as applied to the reference case. Arrows shown on the maps are sized to depict the relative changes in flow from today through 2035. Arrows that increase in width from their origination point to the terminus represent an increasing flow over time, and arrows that decrease in width from their origination point to the terminus represent a declining flow over time. For NGL transport, the arrows are color coded and indicate the type of liquid being transported (raw mix versus pure product versus diluent transport).

The maps also include "production wedges" that depict relative changes in regional production and "import and export wedges" that depict relative changes in import and export activity at various locations. Rail transport corridors are shown as dashed lines on the crude and NGL maps, where applicable.

The main findings observed in the stylized natural gas flow map below are as follows:

- Over time, production increases are greatest in the Marcellus production area, the shale plays in the southwestern production area, and shale plays in Western Canada.
- Increasing production from the Marcellus shale play displaces gas transport to the northeastern United States and provides incremental gas supplies to Eastern Seaboard, midwestern, and southeastern gas markets.
- Flows through the Tennessee Valley that originate from the Gulf Coast decline over time as a result of Marcellus production increases displacing transport into the area.
- Growing production from the Gulf Coast mostly remains in that area to meet local demand growth.
- Incremental production from the Southwest also

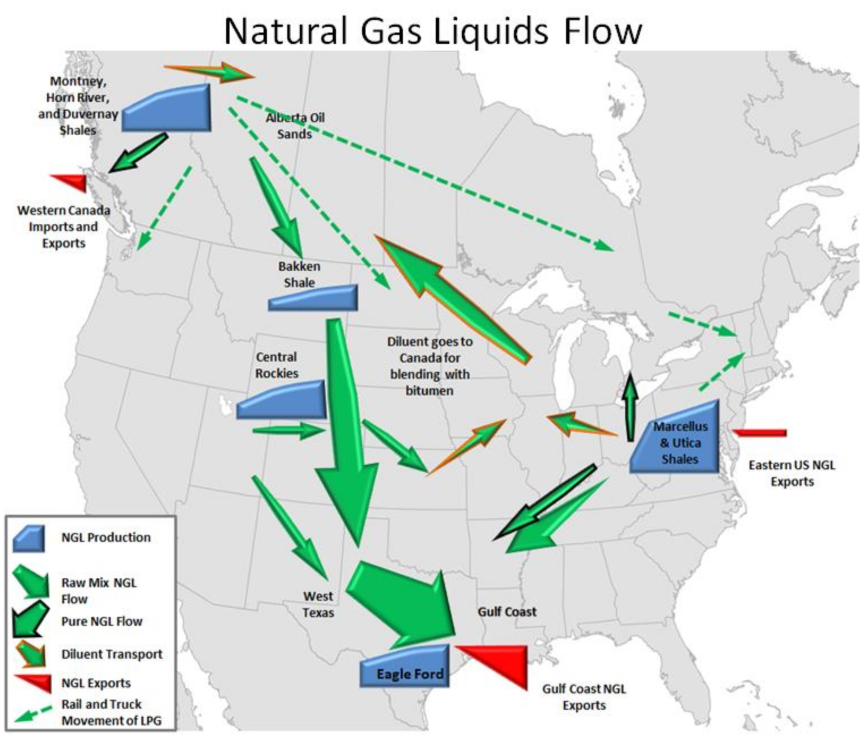


flows to the southeastern states to satisfy increased power-generation demand in the region.

- The Gulf Coast region of Texas and Louisiana becomes home to most of the LNG exports from North America, with additional exports from the East Coast and Western Canada.
- Despite significantly growing production from Western Canada's shale plays, flows out of that area decline significantly as much of the incremental production remains in the area to fuel its oil sands development.
- Incremental production flows to British Columbia's coastline to be exported as LNG.
- Growing Rocky Mountain production mostly flows to the West Coast to offset declines in transport from Western Canada and the Permian Basin of West Texas.
- Ontario's increasing gas needs are met via transport from the United States as flows into the province from Western Canada decline.
- New England's increasing gas needs are met by Marcellus gas. This gas will displace both flows from Eastern Canada and gas from the Gulf Coast region.

The main findings observed in the stylized NGL flow map below are as follows:

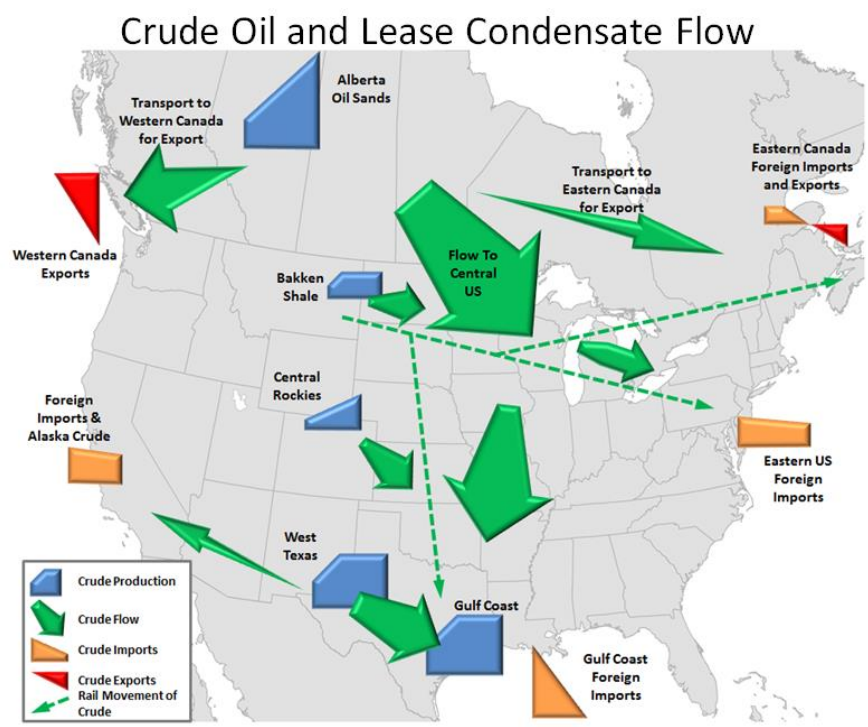
- Over time, production increases are greatest in the Marcellus production area.
- Production growth also occurs in the Bakken, Niobrara, and Eagle Ford shale plays, as well as Western Canada's shale plays.
- Flow increases are the greatest from the Marcellus shale play and in the U.S. mid-continent, where a number of NGL streams come together.
- Marcellus NGL flows mostly toward Mont Belvieu, Texas, on a number of new liquids transport lines, including lines formerly transporting natural gas that are repurposed for liquids transport.
- Increases in production from the Bakken and Niobrara plays mix with NGLs transported from Western Canada to the United States and flow further south toward Mont Belvieu.
- The largest markets for ethane are mostly in the Southwest, where new ethylene production facilities are being built.
- While propane is used for space heaters and water heating, much of the incremental propane produced is transported to new polypropylene production facilities and propane export terminals that are mostly in the Southwest.
- Propane exports also increase from Western Canada and the Eastern Seaboard.



- Some ethane is likely to remain in the natural gas stream and be exported at LNG export facilities along the Gulf Coast and the West Coast of Canada.
- Diluents (mostly pentanes plus) transport increases from the United States into Western Canada where the diluents are needed to aid in the transport of the heavier crudes developed from Western Canada's oil sands.
- Some rail transport (mostly propane) continues to occur from Western Canada.

The main findings observed in the stylized crude oil flow map below are as follows:

- Over time, production increases are greatest from Western Canada and the Gulf Coast and mid-continent producing areas.
- Western Canada's oil sands production is transported to a number of areas, most notably into the United States and to British Columbia for export from the West Coast. The most significant exports of crude occur from Canada's West Coast.
- Some crude flows east for export from Canada's East Coast.
- West Texas crude from the Cline and other Permian Basin plays flows both east and west along new pipelines.
- Increasing Gulf Coast production, mostly from the Eagle Ford play, remains in the Gulf Coast area.
- Crude imports to the United States, especially to Gulf Coast refineries, decline significantly over time as U.S. and Western Canadian supplies replace imported supplies. However, refineries may need to be enhanced to use North American crudes.
- Some Bakken crude moves incrementally eastward, displacing imported oil at East Coast refineries.
- Crude transported westward from the Permian Basin may pose some challenges for West Coast refineries. Some may require enhancements to use the crude.
- Most incremental construction of pipelines to transport increasing crude supplies is in Western Canada and in the central United States.
- Refinery runs may increase somewhat over time as crude production grows and the incremental refined products likely will be exported, as U.S. markets for the products remain fairly flat.



Changes in Capacity for Natural Gas

New natural gas supplies entering the interstate pipeline system will require additional pipeline capacity. The base case shows that approximately 43 Bcfd of incremental natural gas mainline capacity will be needed from 2014 to 2035, as shown in the pipeline capacity table below. This is a modest increase of 0.2 Bcfd per year over capacity additions in the 2011 study, which projected 1.7 Bcfd of capacity added per year through 2035.

Regionally, the most noticeable capacity additions are out of the northeastern and southwestern states. The northeastern capacity additions are mostly driven by Marcellus and Utica gas development. The southwestern additions are driven by growth in production from the Eagle Ford and Haynesville shale plays, as well as a number of other unconventional plays. The Southwest also is home to significant load growth, especially in the form of gas exports to Mexico and at LNG terminals, and growing petrochemical gas use. The southeastern and central states will experience significant capacity additions, mostly to deliver gas to power plants. These regions will see significant coal plant retirements, with gas-fired capacity serving as the primary replacement.

The majority of the capacity additions occur over the next decade. This coincides with the robust production and market growth that occurs during the next 5 to 10 years. After that, both production and market growth slows, with natural gas pipeline expansion slowing accordingly. In addition to the new capacity additions discussed here, pipeline laterals will be required to connect directly to new facilities and new consumption points, and new gas processing will be needed to remove liquids and make gas suitable for pipeline transportation and downstream consumption. Those needed enhancements in the midstream sector are not reflected in the table below, but are detailed later as part of the NGL discussion.

Inter-Regional Natural Gas Pipeline Capacity Added (Billion Cubic Feet per Day)

Originating Region	2014-2020	2021-2025	2026-2030	2031-2035	2014-2035	Average Annual 2014-2035
U.S. and Canada	**24.2**	**6.9**	**8.4**	**3.4**	**42.9**	**1.9**
U.S.	**23.2**	**5.9**	**7.9**	**2.9**	**39.9**	**1.8**
Canada	**1.0**	**1.0**	**0.5**	**0.5**	**3.0**	**0.1**
Central	5.0	-	1.4	0.8	7.2	0.3
Midwest	3.0	0.5	-	-	3.5	0.2
Northeast	6.0	2.3	1.9	-	10.1	0.5
Offshore	-	-	-	-	-	-
Southeast	4.4	0.7	1.7	1.1	7.9	0.4
Southwest	4.8	2.0	2.9	0.5	10.2	0.5
Western	-	0.5	-	0.5	1.0	0.0
Arctic	-	-	-	-	-	-

Changes in Capacity for Natural Gas Liquids

Like natural gas pipeline capacity, pipeline capacity for NGL also will grow significantly over the next 20 years. As shown in the table below, the base case projects that 3.6 million barrels per day (MMBPD) of new capacity will be needed throughout the study period. Also, like natural gas capacity, the greatest increase in capacity will occur over the next decade, coinciding with the significant production growth that occurs over the next 5 to 10 years.

Regions with the most significant increases in capacity include the central, northeastern, and southwestern United States, which are areas in relatively close proximity to the production growth. Most of the growth results from transporting liquids from the production areas to points where new petrochemical production facilities are being built. Additional pipeline capacity is needed to allow heavy liquids (pentanes plus) to move to Western Canada, where they can be used to enable the transportation of the relatively heavy crude being developed there. As is the case for the gas transport discussed above, the table does not include lateral capacity to connect to new facilities because that portion of midstream development will be discussed later.

Inter-Regional Natural Gas Liquids Pipeline Capacity Added (Million Barrels per Day)

Originating Region	2014-2020	2021-2025	2026-2030	2031-2035	2014-2035	Average Annual 2014-2035
U.S. and Canada	**3.2**	**0.2**	**0.3**	**-**	**3.6**	**0.2**
U.S.	**2.8**	**-**	**0.3**	**-**	**3.1**	**0.1**
Canada	**0.3**	**0.2**	**-**	**-**	**0.5**	**0.0**
Central	1.0	-	-	-	1.0	0.0
Midwest	0.3	-	0.1	-	0.4	0.0
Northeast	0.9	-	0.2	-	1.1	0.0
Offshore	-	-	-	-	-	-
Southeast	-	-	-	-	-	-
Southwest	0.7	-	-	-	0.7	0.0
Western	-	-	-	-	-	-
Arctic	-	-	-	-	-	-

Changes in Capacity for Oil

Crude oil pipeline capacity also will increase significantly over the next 20 years. An average of 0.5 million BPD of capacity growth is expected per year through 2035. In the United States, slightly more than 80 percent of crude and condensate capacity growth is expected to occur in the Midwest and Southwest to move crude oil to refineries along the Gulf Coast. Canada also is expected to need significant amounts of new inter-regional capacity to export incremental oil sands production. As with natural gas and NGL capacity additions, the majority of the oil transportation additions occur over the next decade, corresponding with the large production changes that occur over the next 5 to 10 years.

Inter-Regional Crude Oil and Lease Condensate Pipeline Capacity Added (Million Barrels per Day)

Originating Region	2014-2020	2021-2025	2026-2030	2031-2035	2014-2035	Average Annual 2014-2035
U.S. and Canada	**7.4**	**1.7**	**0.7**	**0.4**	**10.2**	**0.5**
U.S.	**5.2**	**-**	**0.3**	**-**	**5.4**	**0.2**
Canada	**2.2**	**1.7**	**0.4**	**0.4**	**4.7**	**0.2**
Central	0.5	-	0.3	-	0.7	0.0
Midwest	2.7	-	-	-	2.7	0.1
Northeast	0.2	-	-	-	0.2	0.0
Offshore	-	-	-	-	-	-
Southeast	-	-	-	-	-	-
Southwest	1.7	-	-	-	1.7	0.1
Western	-	-	-	-	-	-
Arctic	-	-	-	-	-	-

Midstream Infrastructure Investment

Significant investment is needed to support the incremental gas movements discussed above. As per the table below, investment in new natural gas transmission capacity (including new mainlines, natural gas storage fields, laterals to/from storage, power plants and processing facilities, gas lease equipment, processing facilities, and LNG export facilities) needed through 2035 is projected to average approximately $14 billion per year, totaling $313 billion (real 2012$).[5] This is in comparison with a total investment of just over $8 billion per year in the prior study.[6]

[5] All costs and investment values in this report are cited as real 2012$ values unless otherwise stated.
[6] Costs in the prior study were reported in 2010$, but have been adjusted to 2012$ in this report by applying inflation between 2010 and 2012 in order to make a direct comparison with current projections possible.

The gas transmission mainline category is projected to account for approximately a quarter of the total capital expenditures required for new gas infrastructure in this study. It accounted for approximately half of the total expenditures in the 2011 study. This shift is attributable mostly to the fact that the new study considers investment categories that were not considered in the prior study. For example, and as mentioned earlier, this study considers investments in gas lease equipment, LNG export facilities, and compression needs for gas gathering—all categories that were not included in the 2011 study.

Comparison of Natural Gas Capital Expenditures in Current Study Versus Prior Study

(Billions of Real Dollars)	Current Study, 2014-2035 (2012$)	Current Study Average Annual (2012$)	Prior Study, 2011-2035 (2012$)*	Prior Study Average Annual (2012$)*
Gas Transmission Mainline Pipe	$87.2	$4.0	$101.5	$4.1
Laterals to/from Power Plants, Gas Storage, and Processing Plants	$45.2	$2.1	$31.0	$1.2
Gathering Line (pipe only)	$35.6	$1.6	$43.3	$1.8
Gas Gathering Line Compression	$23.5	$1.1	NA**	NA**
Gas Lease Equipment	$26.9	$1.2	NA**	NA**
Gas Pipeline & Storage Compression	$11.6	$0.5	$9.5	$0.3
Gas Storage Fields	$12.0	$0.5	$5.0	$0.2
Gas Processing Capacity	$27.4	$1.2	$23.0	$0.9
LNG Export Facilities	$43.7	$2.0	NA**	NA**
Total Capital Expenditures	**$313.1**	**$14.2**	**$213.3**	**$8.5**

*Capital expenditures reported in Prior Study were converted from 2010$ to 2012$ using a 4% inflation factor.
**NA refers to Not Available.

Gathering and processing require almost $4 billion in investments per year, compared with a little more than $2.5 billion per year in the prior study; but again, this new analysis includes compression associated with gathering and processing, which was not included in the prior study. Laterals to/from storage fields, power plants, and processing facilities require more than $2 billion per year in investments in the current study, compared with just over $1 billion per year in the prior study. Investment in new gas lease equipment, including pumps, flowlines and connections, and dehydrators, will total just over $1 billion per year. Storage and LNG export investments averaging about $3 billion per year round out the total investments in this current study.

As mentioned earlier, several gas and oil plays have high gas liquids content and significant growth in NGL production is expected. To support the supply and demand balance of NGLs, expansion of the existing NGL pipeline network could require an average capital investment of $1.3 billion per year through 2035, or almost $30 billion throughout the projection, as shown in the table below.[7] This is roughly double the level of investment in the prior study. Absent these pipeline additions, alternative modes of transportation could include rail shipments and trucking. However, pipelines are generally thought to be the most cost-competitive option for NGL transport.

In addition to this significant investment in new NGL transportation, an additional $1.3 billion in investment in NGL fractionation and export facilities is required each year. These categories were not part of the 2011 study. The total investment in NGL midstream infrastructure is $2.6 billion per year, or almost $60 billion throughout the projection.

Comparison of Natural Gas Liquids (NGL) Capital Expenditures in Current Study Versus Prior Study

(Billions of Real Dollars)	Current Study, 2014-2035 (2012$)	Current Study Average Annual (2012$)	Prior Study, 2011-2035 (2012$)	Prior Study Average Annual (2012$)
NGL Transmission Mainline (pipe and pump)	$29.0	$1.3	$15.1	$0.6
Pipe	*$26.4*	*$1.2*	*$14.8*	*$0.6*
Pump	*$2.5*	*$0.1*	*$0.3*	*$0.0*
NGL Fractionation	$21.1	$1.0	NA	NA
NGL Export Facilities	$5.9	$0.3	NA	NA
Total Capital Expenditures	**$56.0**	**$2.6**	**$15.1**	**$0.6**

Significant infrastructure also will be required to support incremental oil production. As already pointed out, an additional 10 million BPD of new pipeline capability will be needed to transport incremental oil production over the projection period. Thus, expansion of the existing oil pipeline grid, including oil gathering lines, could have a capital cost of almost $3.5 billion per year, totaling more than $75 billion throughout the projection period. Projected capital expenditures for oil transport have more than doubled from the levels projected in the prior study, mostly as a result of the revised outlook for oil production that is much more robust than the prior projection.

In addition to the investment in oil pipelines, almost $9 billion per year (approaching a total of $200 billion over the projection period) will be required for new surface equipment to support incremental oil production. This surface equipment includes pumps, valves and manifolds, flowlines and connections, stock tanks, separators, and heater-treaters.

[7] Costs for laterals needed to connect with fractionation plants, petrochemical facilities, and export terminals are included in these cost estimates.

A modest investment in new oil storage terminals rounds out the total to over $12 billion per year, bringing total midstream infrastructure investment related to oil production and transport to $270 billion throughout the projection period.

Comparison of Crude Oil Capital Expenditures in Current Study Versus Prior Study

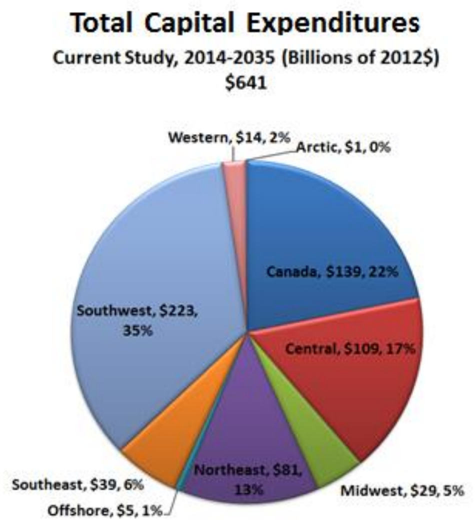
(Billions of Real Dollars)	Current Study, 2014-2035 (2012$)	Current Study Average Annual (2012$)	Prior Study, 2011-2035 (2012$)	Prior Study Average Annual (2012$)
Crude Oil Gathering Line (pipe only)	$12.7	$0.6	NA	NA
Crude Oil Lease Equipment	$192.6	$8.8	NA	NA
Crude Oil Transmission Mainline (pipe and pump)	$63.3	$2.9	$32.6	$1.4
Pipe	*$53.5*	*$2.4*	*$31.2*	*$1.3*
Pump	*$9.8*	*$0.4*	*$1.5*	*$0.1*
Crude Oil Storage Laterals	$1.5	$0.1	NA	NA
Crude Oil Storage Tanks	$1.7	$0.1	NA	NA
Total Capital Expenditures	**$271.8**	**$12.4**	**$32.6**	**$1.4**

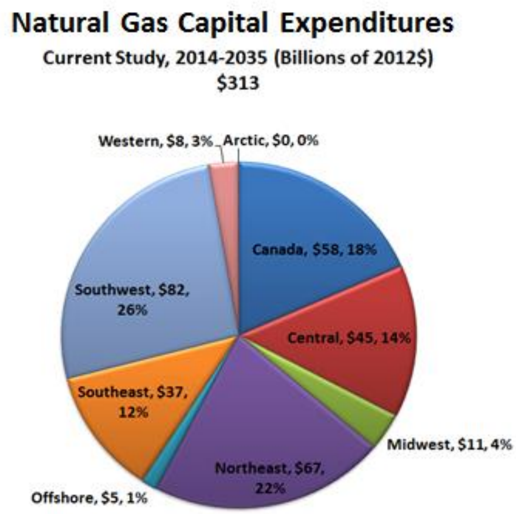
Regional Investment in Midstream Infrastructure

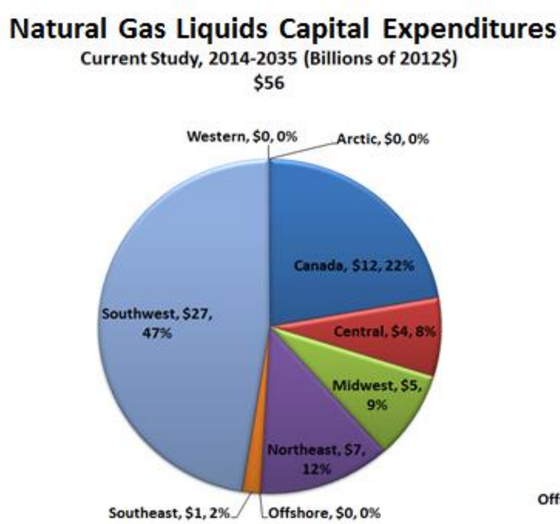
It should probably be no surprise that the largest share of regional investment in midstream infrastructure will occur in the Southwest (New Mexico, Texas, Oklahoma, Louisiana, and Arkansas), which historically has been an area of significant hydrocarbon development. Midstream infrastructure investment in this area is expected to total more than $220 billion throughout the projection period. The area experiences significant investment in infrastructure, supporting development of oil, gas, and liquids. Midstream infrastructure associated with oil development accounts for almost half of the region's investment in new midstream infrastructure. This is not surprising because more than half of the refineries in the United States are located in the area. Investment in gas-related infrastructure also is important for the region because it will be home to significant growth in gas production and load growth at petrochemical and LNG export facilities.

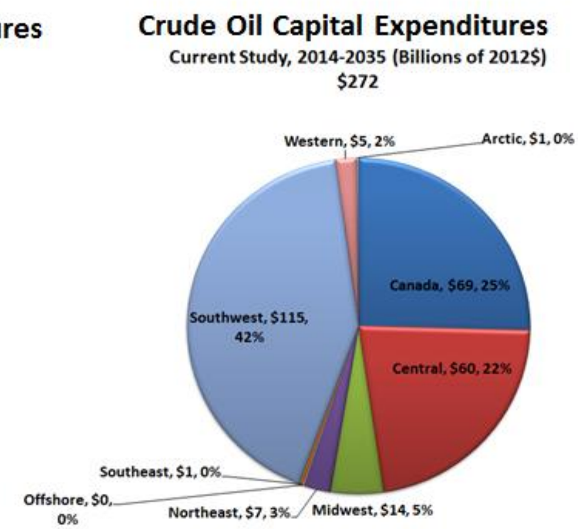
Canada and the central United States also are likely to experience significant investments in new midstream infrastructure as a result of the robust development of resources within those areas. These regions account for almost $140 billion and $110 billion, respectively, in midstream investments. Gas infrastructure investment in these areas is needed to support the growing production of shale resources and to facilitate pipeline transport to markets and export facilities.

The Northeast also is poised for midstream infrastructure growth, with investments totaling more than $80 billion throughout the projection. The area is home to gas-prone development from the Marcellus shale play that spurs almost $70 billion in investments in gas-related infrastructure.









Investment in Different Diameters/Grades of Pipe for Gathering and Transport

The table below shows that more than 500,000 miles of new pipeline and almost 17 million horsepower for new compression and pumping capabilities will be needed for gas, NGL, and oil gathering and transport throughout the projection period. Total pipeline, compression, and pumping expenditures are projected to total almost $310 billion throughout the projection period. More than 60 percent of the new pipe and compression will be needed for natural gas gathering and transport, with oil and NGL gathering and transport accounting for the remainder.

Pipes with a diameter greater than 24 inches will account for more than 40 percent of the pipeline and gathering line investments even though they account for less than 5 percent of the total miles added during the study period. This is because pipes of that size have a much greater unit cost than smaller diameter pipes. Pipes with diameters less than or equal to 8 inches account for the majority of new pipe mileage that is needed over time, but investment in such facilities is more modest at roughly 20 percent of the total investment. These smaller diameter pipes are mostly used for gathering gas, oil, and NGLs.

Historically, the industry has proven its ability to finance and construct the levels of pipeline and gathering capability projected here, and there is no reason to believe that it cannot handle the infrastructure requirements projected in this study and reflected in the table below. Industry investments in new gathering and transport lines have averaged roughly $10 billion per year over the past decade, so the levels of future investment are consistent with the pipeline construction that already has occurred. During the past decade, companies active in the midstream space have placed into service roughly 15,000 miles of new natural gas pipelines at a cost of more than $50 billion, and the totals in the large-diameter category are consistent with that level of activity.

Pipeline Capital Expenditures by Diameter Class for Current Study, 2014-2035

(Thousand Miles)	1" to ≤ 8"	> 8" to ≤ 16"	> 16" to ≤ 24"	> 24"	Total	% of Total
Natural Gas	291.2	24.3	9.6	13.7	**338.8**	**62%**
NGL	0.8	10.3	3.9	0.1	**15.1**	**3%**
Crude Oil	171.6	2.0	2.5	12.5	**188.6**	**35%**
Total	**463.6**	**36.6**	**16.0**	**26.3**	**542.5**	**100%**
(Thousand HP)	**1" to ≤ 8"**	**> 8" to ≤ 16"**	**> 16" to ≤ 24"**	**> 24"**	**Total**	**% of Total**
Natural Gas	7,647	3,300	103	1,740	**12,790**	**75%**
NGL	397	83	166	16	**661**	**4%**
Crude Oil	336	79	243	2,847	**3,505**	**21%**
Total	**8,380**	**3,462**	**512**	**4,603**	**16,956**	**100%**
(Billions of 2012$)	**1" to ≤ 8"**	**> 8" to ≤ 16"**	**> 16" to ≤ 24"**	**> 24"**	**Total**	**% of Total**
Natural Gas	$50.1	$40.9	$33.7	$78.3	**$203.0**	**66%**
NGL	$2.5	$18.4	$7.8	$0.2	**$29.0**	**9%**
Crude Oil	$13.8	$2.0	$7.1	$54.6	**$77.5**	**25%**
Total	**$66.5**	**$61.3**	**$48.6**	**$133.2**	**$309.5**	**100%**

Metrics for Infrastructure Development

Robust growth in hydrocarbon production from unconventional resources will remain the primary driver of midstream infrastructure development. The ICF base case projects that significant development of unconventional supplies will continue in the foreseeable future, with more than 1.2 million well completions projected for the United States and Canada over the projection period. Three-quarters of the wells will be oil wells, with the balance being gas wells. The focus on oil development is the result of relatively high oil prices projected during the forecast period. Although significantly fewer gas wells are projected in this current study when compared with the prior study, projected gas well activity remains sufficiently robust to grow gas production significantly. This is because gas wells generally are much more productive than a few years ago thanks to improved horizontal drilling and fracturing applications. The projected oil and gas well activity and resulting production levels are the primary drivers of new gathering systems, processing and fractionation facilities, and lease equipment.

Comparison of Natural Gas Metrics in Current Study Versus Prior Study

	Current Study, 2014-2035	Current Study Average Annual	Prior Study, 2011-2035	Prior Study Average Annual
Gas Well Completions (1000s)	307	14	729	29
Oil Well Completions (1000s)	914	42	777	31
Total Well Completions (1000s)	1,221	56	1,506	60
Miles of Transmission Mainline (1000s)	18.6	0.8	35.6	1.4
Miles of Laterals to/from Power Plants, Storage Fields, and Processing Plants (1000s)	17.1	0.8	13.9	0.6
Miles of Gas Gathering Line (1000s)	303.1	13.8	414	16.5
Inch-Miles of Transmission Mainline (1000s)	568	26	1,043	42
Inch-Miles of Laterals to/from Power Plants, Storage Fields, and Processing Plants (1000s)	279	13	304	12
Inch-Miles of Gathering Line (1000s)	1,095	50	1,518	61
Compression for Pipelines (1000 HP)	4,388	199	4,946	197
Compression for Gathering Line (1000 HP)	8,402	382	NA	NA
Gas Storage (Bcf Working Gas)	823	37	589	24
Processing Capacity (Bcfd)	34.2	1.6	32.5	1.3
LNG Export Facilities (Bcfd)	9.3	0.4	NA	NA

Increased production levels and associated market growth drive projections for gas pipeline infrastructure. In addition to the 303,000 miles of gas gathering lines projected, the ICF base case projects 35,000 miles of new transmission pipelines (including both mainline and laterals) over the projection period. While this mileage is significantly less than the prior study because many of the projects currently planned and proposed are shorter haul expansions of the transmission system, this is still a substantial amount of new pipe.[8] Along with this pipe, the base case projects nearly 13 million horsepower of compression for new gathering and transmission capacity, most of which is for gathering systems. The base case projects more than 800 Bcf of new working gas capability for gas storage, more than 34 Bcfd of new gas processing capability, and assumes more than 9 Bcfd of new LNG export capacity. These values are all well above the levels in the prior study, largely because shale resource development is continuing to make cost-effective gas supplies available for markets.

The metrics for NGL development are equally impressive. The current study includes more than 15,000 miles of new NGL transmission lines over the projection period.[9] New lines are supported with roughly 660,000 horsepower of pumping to move the liquids through the pipelines. More than 3.3 million barrels of fractionation capacity separates the liquids into various components, and roughly 1.4 million BPD of new export capacity facilitates the movement of liquids to foreign countries. All of the liquids metrics are greater than projected in the 2011 study due to the increased levels of liquids production in this current projection.

Comparison of Natural Gas Liquids Metrics in Current Study Versus Prior Study

	Current Study, 2014-2035	Current Study Average Annual	Prior Study, 2011-2035	Prior Study Average Annual
Miles of NGL Transmission Mainline (1000s)	15.1	0.7	12.5	0.5
Inch-Miles of NGL Transmission Mainline (1000s)	220	10	164	7
Pump for NGL Transmission Mainline (1000 HP)	661	30	166	7
Fractionation Capacity Built (MBOE*/d)	3,326	151	NA	NA
NGL Export Facility Capacity Built (MBOE/d)	1,402	64	NA	NA

*MBOE refers to Million Barrels of Oil Equivalent.

The metrics that are perhaps most impressive in this study are those related to oil infrastructure development. As mentioned before, the projection applied here includes a large number of oil wells – more than 900,000 wells throughout the projection – due to the relatively high assumed oil prices going forward. The large number of oil wells completed over time will lead to the significant levels of investment in new surface equipment. After the oil leaves the production area, much of it is delivered through new oil transmission lines. The projection calls for construction of more than 16,000 miles of

[8] The average miles of pipe built per project for mainline expansions in the prior study was 293 miles per expansion, versus only 138 miles per expansion in this new study.

[9] Laterals needed to connect with fractionation plants, petrochemical facilities, and export terminals are included in these mileage estimates.

new oil transmission lines supported by roughly 3.5 million horsepower of new pumping capability. The other alternatives for oil transport are rails and trucks, and this projection assumes that the levels of rail and truck transport of crude oil remain fairly constant with today's levels. Admittedly, this assumption is not unquestioned as rails and trucks have "optionality" advantages over pipelines. That is to say that rail and truck movement is more flexible than pipeline transport because routes can shift in response to market conditions. However, rail and truck movement is much more expensive than pipeline transportation on a unit cost basis, and this analysis assumes that the most economic options will be selected over time.

This analysis also projects more than 130 million barrels of new crude oil storage capability over the projection period. This expansion equates to about one-quarter of the crude oil terminal capability that is already in place in the United States and Canada. The new crude oil capacity is vital to ensuring that production can be stored temporarily when refineries are removed from service for maintenance and to enable producers to manage temporal imbalances in markets.

Comparison of Crude Oil Metrics in Current Study Versus Prior Study

	Current Study, 2014-2035	Current Study Average Annual	Prior Study, 2011-2035	Prior Study Average Annual
Oil Well Completions (1000s)	914	42	777	31
Miles of Crude Oil Gathering Line (1000s)	171.6	7.8	NA	NA
Miles of Transmission Mainline (1000s)	16.2	0.7	19.3	0.8
Miles of Crude Oil Storage Laterals (1000s)	0.8	0	NA	NA
Inch-Miles of Crude Oil Gathering Line (1000s)	379	17	NA	NA
Inch-Miles of Transmission Mainline (1000s)	432	20	355	15
Inch-Miles of Crude Oil Storage Laterals (1000s)	14	1	NA	NA
Pump for Transmisson Mainline (1000 HP)	3,505	159	754	31
Crude Storage Capacity Built (MMBbl*)	133	6	NA	NA
Number of Crude Storage Tanks Built	26,504	1,205	NA	NA
Number of Crude Storage Farms Built	39	2	NA	NA

*MMBbl refers to Million Barrels.

Low-Growth Case

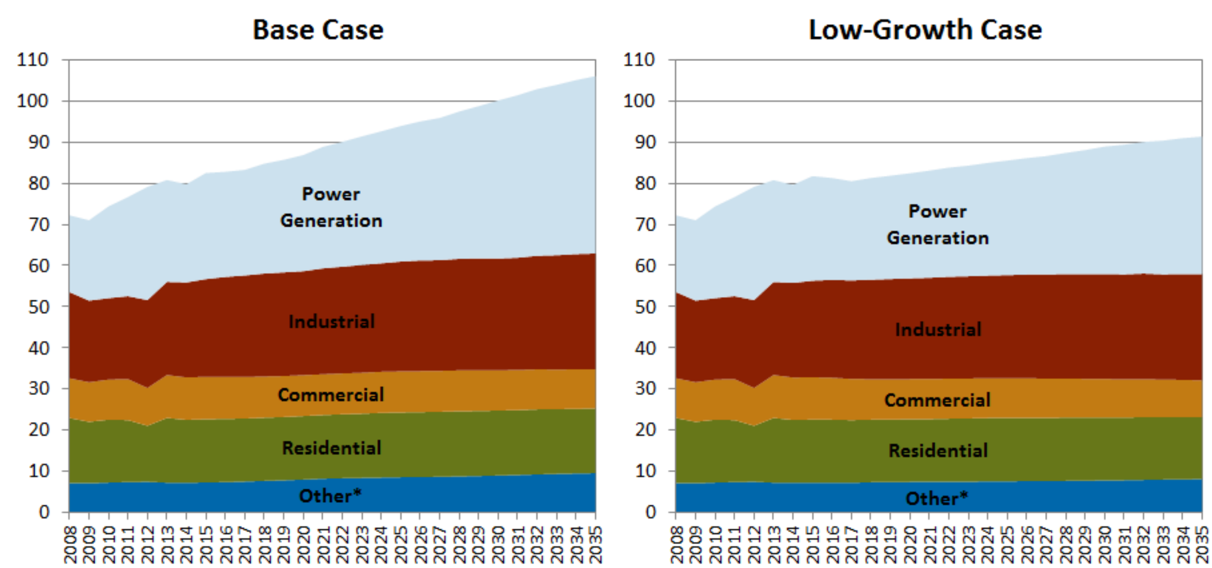
The ICF base case represents a likely scenario, but this study also includes a low-growth scenario in an effort to assess a more conservative expectation for midstream infrastructure development. The assumptions and results for the low-growth scenario are discussed in this section.

Price and Demand Assumptions for the Low-Growth Case

The low-growth case presented in this study assumes a markedly lower growth environment for hydrocarbon use in the foreseeable future. This case assumes that global economic conditions are not as robust as in the base case. Asian economies are generally assumed to grow at a slower rate than in the base case as they mature and rationalize fiscal and monetary policies. Persistent problems related to deficit spending in the United States and Europe also contribute to the reduced economic growth.

As a result, the U.S. economy grows by roughly 30 percent less than in the base case. The reduced rate of economic activity does not bode well for energy use, leading to reduced electric load growth and lower levels of industrial production that adversely affect natural gas consumption for power generation and in the petrochemical sector. As a result, total gas use in the low-growth case is about 15 Bcfd, or about 15 percent lower than the base case. Gas use rises to roughly 91 Bcfd by 2035, versus approximately 106 Bcfd in the base case.[10] Although not shown in the figure below, liquids market growth also is significantly lower in this low-growth case, and U.S. refinery runs are down modestly compared with the base case levels.

U.S. and Canadian Gas Consumption (Average Annual Bcfd)



**Other includes lease, plant, and pipeline fuel gas use.*

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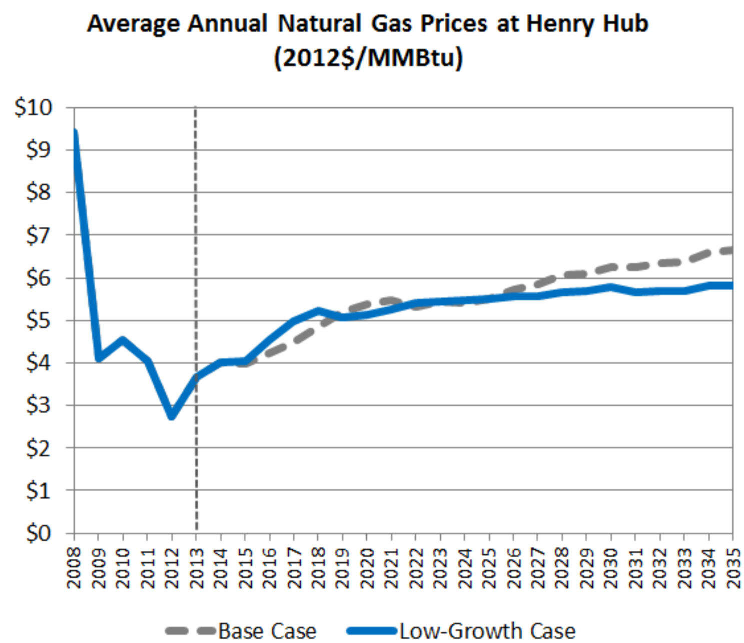
[10] These numbers do not include LNG exports, which are also down in the low-growth case by 5 Bcfd, as further explained below. So, the total reduction in load is about 20 Bcfd, or closer to 20 percent of total load.

Perhaps of equal importance is that this case assumes that global oil use and, thus, oil prices, are significantly lower than in the base case. Instead of remaining constant at $100 per barrel, oil prices slowly decline to $75 per barrel over the projection period as a result of the reduced growth of oil use. This has a variety of adverse effects on gas disposition and liquids market development, the most notable of which is that LNG exported from North America will not be nearly as competitive, particularly in Asia where landed prices for LNG have historically moved with oil prices. With the expectation that landed prices for LNG will decline as oil prices decline, it becomes more difficult for LNG from North America to compete with LNG sources that are closer to Asian consumers. As a result, North America's LNG exports are assumed to be 4 Bcfd in the low-growth case, compared with 9 Bcfd in the base case. When coupled with the reduced growth of domestic gas use, markets for gas and liquids are not nearly as robust as in the base case.

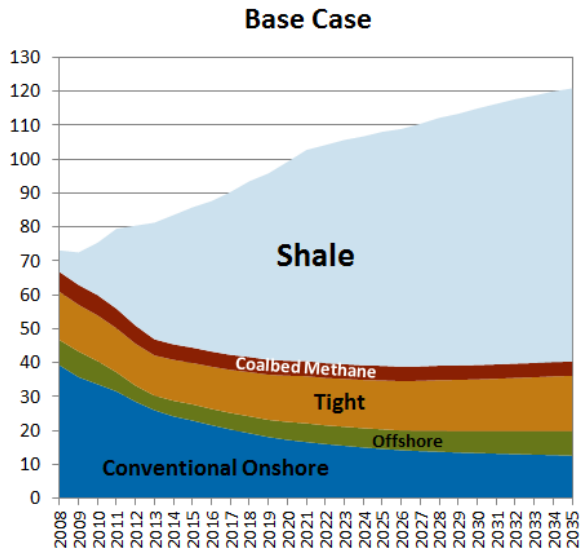
Gas price levels in this low-growth case are not dramatically different from levels projected in the base case. While it is reasonable to expect that gas prices would be lower due to the reduced market growth, the countervailing impact is that lower oil prices spur less oil and NGL development, increasing the cost of gas development. In short, the "liquids uplift," or subsidization of gas development, is not as great in the assumed lower oil price environment. So, not only are there fewer gas consumers over time, but there is less abundant gas supply for the consumers that remain.



Resource/Supply Assumptions for the Low-Growth Case

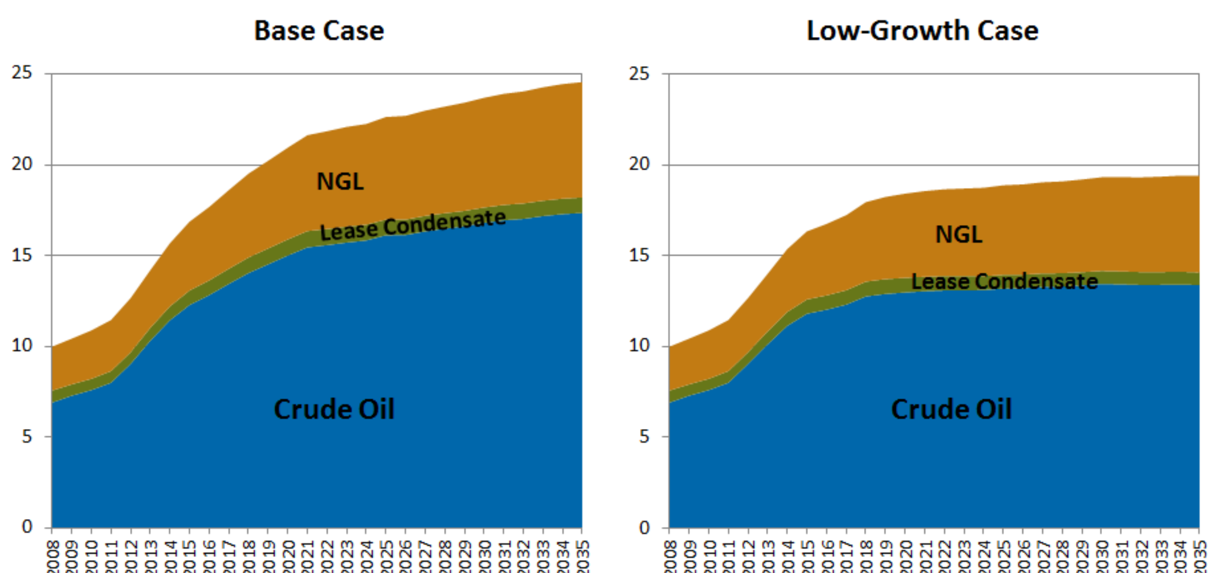
Because of the lower market growth and reduced economic incentives for gas development, gas production growth in the low-growth case lags significantly behind production growth in the base case. The low-growth case projects that U.S. and Canadian gas production will rise to almost 100 Bcfd, compared with more than 120 Bcfd in the base case. The production growth rate in this low-growth case, at merely 1 percent per year, is almost one full percentage point below the growth in the base case. Nonetheless, significant growth in production and significant supply shifts still occur over time as shale gas production remains preferred over conventional resources. The growth of shale gas production will still provide ample midstream infrastructure development opportunities, as discussed below.

U.S. and Canadian Natural Gas Production (Average Annual Bcfd)



As is the case for gas production, the growth of oil and NGL production is adversely affected by the assumptions in this low-growth case, particularly the assumption for falling oil prices in real terms. As shown below, U.S. and Canadian crude oil production is reduced by 5 million BPD by 2035 versus the base case. Half of this reduction occurs in Alberta's oil sands, with much of the balance resulting from reduced activity in tight oil supplies. Projected NGL production in this low-growth case is down 15 percent by 2035 compared with the base case. The lower levels of oil and NGL development will result in lower levels of midstream infrastructure development, but it is still noteworthy that oil and NGL development are projected to remain above today's levels during the next decade. So, as discussed below, midstream infrastructure development remains attractive, but the investments are likely to be more selective and more narrowly focused than in the base case.

U.S. and Canadian Liquid Production (Average Annual Million BPD)



Infrastructure Investment in the Low-Growth Case

The low-growth case yields midstream infrastructure expenditures that are less than those projected in the base case. The following tables illustrate this by comparing projected capital expenditures in the two scenarios.

The first table shows that expenditures for gas infrastructure will be roughly two-thirds of the expenditures in the base case. The reductions in market growth suggest that there should be an even more pronounced reduction in development than what is observed in the table. As noted above, shale resource development will continue to shift supply away from conventional production over time, necessitating midstream infrastructure development to deliver the new shale supplies.

Perhaps the most noticeable change, and most certainly the largest percent change from the base case, is the projected investment in LNG export facilities. Development of those facilities is hindered by the reduced oil prices and, thus, the lower landed prices for LNG in this alternate scenario. It is worth noting that there is a lot of momentum behind development of North American LNG export facilities, so the facilities may well be developed regardless of what happens with oil prices. Still, the low-growth case illustrates the risk that lower oil prices would pose for development of the facilities and, ultimately, the level of gas exports from the facilities.

Comparison of Natural Gas Capital Expenditures in Base Case Versus Low-Growth Case

(Billions of Real Dollars)	Base Case, 2014-2035 (2012$)	Base Case Average Annual (2012$)	Low-Growth Case, 2014-2035 (2012$)	Low-Growth Case Average Annual (2012$)	Average Annual Change (2012$)	Average Annual Change (%)
Gas Transmission Mainline Pipe	$87.2	$4.0	$59.2	$2.7	-$1.3	-32%
Laterals to/from Power Plants, Gas Storage, and Processing Plants	$45.2	$2.1	$29.3	$1.3	-$0.7	-35%
Gathering Line (pipe only)	$35.6	$1.6	$29.9	$1.4	-$0.3	-16%
Gas Gathering Line Compression	$23.5	$1.1	$16.8	$0.8	-$0.3	-29%
Gas Lease Equipment	$26.9	$1.2	$21.9	$1.0	-$0.2	-19%
Gas Pipeline & Storage Compression	$11.6	$0.5	$7.6	$0.3	-$0.2	-34%
Gas Storage Fields	$12.0	$0.5	$5.9	$0.2	-$0.3	-51%
Gas Processing Capacity	$27.4	$1.2	$19.8	$0.9	-$0.3	-28%
LNG Export Facilities	$43.7	$2.0	$14.9	$0.7	-$1.3	-66%
Total Capital Expenditures	**$313.1**	**$14.2**	**$205.3**	**$9.3**	**-$4.9**	**-34%**

When investment in LNG export facilities is excluded, declines in investment in other categories are generally in line with the overall decline. It is interesting to note, however, that declines in investment in gas gathering and surface equipment associated with gas development are more modest than the overall decline. This is because there are still significant amounts of shale resource development in this low-growth case, and gathering assets and surface equipment are not as easily substituted as are under-utilized pipelines. Under-utilized pipelines may be used to transport incremental gas molecules because interstate pipelines already extend over wide geographic areas. On the other hand, gathering systems and surface equipment support production from specific areas, and are much less expansive in their geographic reach.

As is the case for gas infrastructure development, oil and NGL infrastructure development are lower in the low-growth case. The tables below show that NGL and oil infrastructure development are down by $15 billion, or 26 percent, and roughly $54 billion, or 20 percent, respectively, compared with the base case.

On a percentage basis, reductions for oil and NGL infrastructure development are below the reduction for gas infrastructure development. This is because there is less pipeline capability to move oil and NGL (i.e., the transmission network for liquids is much sparser and less developed than the gas transmission network), so significant pipeline investments still are required to transport new oil and NGL supplies. However, the uncertainties created by relatively lower oil and liquids prices in this scenario still pose risks and challenges for new pipelines. Specifically, subscribers of new capacity are likely to be more hesitant about longer term investments and may attach a greater value to optionality in the riskier environment depicted by the scenario. On the other hand, in areas where supply development is most cost effective and not as risky, pipelines remain an attractive alternative because they offer a lower unit cost for transport compared with rail and trucking alternatives.

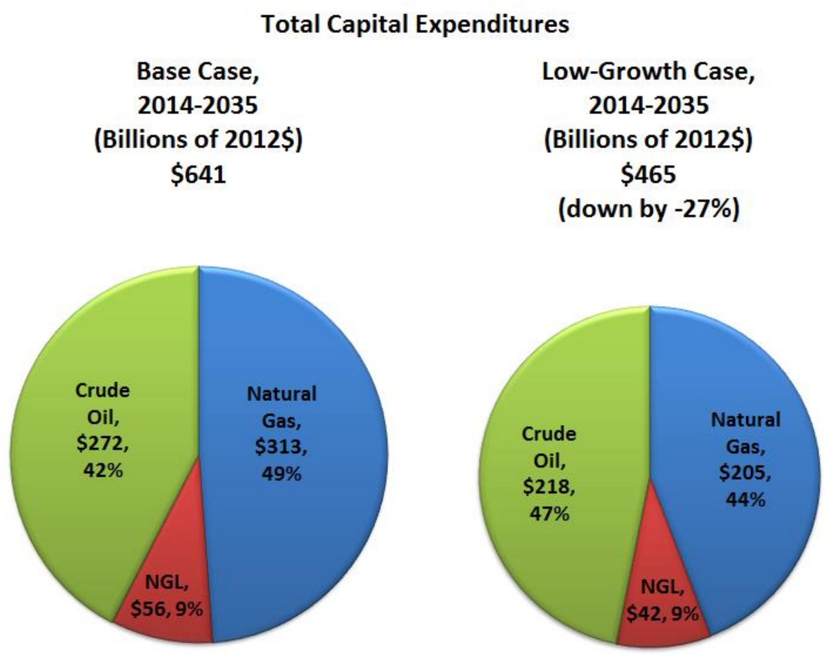
Comparison of Natural Gas Liquids Capital Expenditures in Base Case Versus Low-Growth Case

(Billions of Real Dollars)	Base Case, 2014-2035 (2012$)	Base Case Average Annual (2012$)	Low-Growth Case, 2014-2035 (2012$)	Low-Growth Case Average Annual (2012$)	Average Annual Change (2012$)	Average Annual Change (%)
NGL Transmission Mainline (pipe and pump)	$29.0	$1.3	$22.4	$1.0	-$0.3	-23%
Pipe	*$26.5*	*$1.2*	*$21.0*	*$0.9*	*-$0.2*	*-20%*
Pump	*$2.5*	*$0.1*	*$1.3*	*$0.1*	*-$0.1*	*-47%*
NGL Fractionation	$21.1	$0.9	$15.9	$0.7	-$0.2	-25%
NGL Export Facilities	$5.9	$0.3	$3.5	$0.2	-$0.1	-42%
Total Capital Expenditures	**$56.0**	**$2.5**	**$41.7**	**$1.9**	**-$0.7**	**-26%**

Comparison of Crude Oil Capital Expenditures in Base Case Versus Low-Growth Case

(Billions of Real Dollars)	Base Case, 2014-2035 (2012$)	Base Case Average Annual (2012$)	Low-Growth Case, 2014-2035 (2012$)	Low-Growth Case Average Annual (2012$)	Average Annual Change (2012$)	Average Annual Change (%)
Crude Oil Gathering Line (pipe only)	$12.7	$0.6	$11.1	$0.5	-$0.1	-13%
Crude Oil Lease Equipment	$192.5	$8.8	$163.7	$7.4	-$1.3	-15%
Crude Oil Transmission Mainline (pipe and pump)	$63.3	$2.9	$41.1	$1.9	-$1.0	-35%
Pipe	*$53.5*	*$2.4*	*$35.2*	*$1.6*	*-$0.8*	*-34%*
Pump	*$9.8*	*$0.4*	*$5.9*	*$0.3*	*-$0.2*	*-40%*
Crude Oil Storage Laterals	$1.5	$0.1	$0.9	$0.0	$0.0	-43%
Crude Oil Storage Tanks	$1.7	$0.1	$1.0	$0.0	$0.0	-40%
Total Capital Expenditures	**$271.8**	**$12.4**	**$217.8**	**$9.9**	**-$2.5**	**-20%**

The pie chart below summarizes the infrastructure expenditures projected across each of the hydrocarbons for both scenarios considered herein. It shows that total investment in midstream infrastructure will be roughly $460 billion in the low-growth case, compared with roughly $640 billion in the base case. The chart also illustrates the slight shift of development toward oil and liquids, and away from gas infrastructure development. Again, this is likely due to the relative sparseness of the pipeline network for oil and NGL transport when compared with the natural gas pipeline network. In addition, greatly reduced LNG exports in the low-growth case have a disproportionate effect on gas infrastructure development.



Infrastructure Metrics in the Low-Growth Case

The three tables below compare the metrics for infrastructure development in the low-growth case with the base case values to illustrate where reductions in development occur over time. The tables also illustrate that a large amount of new midstream infrastructure still will be needed, even in a lower growth environment. Even though market growth is greatly reduced in the low-growth case, supply shifts created by shale resource development continue to be an important driver of new midstream infrastructure.

In the low-growth case, well completions drop by 15 to 20 percent compared with the base case, while gathering line mileage falls by roughly 70,000 miles, or 15 percent, over the projection period. That is a reduction of roughly 50,000 miles (16 percent) for gas gathering and roughly 20,000 miles (13 percent) for oil gathering. Likewise, new pipeline construction is down, with new gas pipeline additions (including both mainline and lateral projects) reduced by 32 percent, or nearly 12,000 miles; new NGL pipeline additions reduced by 18 percent, or more than 2,500 miles; and oil pipeline additions reduced by 37 percent, or roughly 6,000 miles over the projection period. Similarly, new compression and pumping capability for gas, NGL, and oil transport is reduced by 1.5 million horsepower (34 percent), 270,000 horsepower (40 percent), and 1.5 million horsepower (42 percent), respectively. Other metrics, including new processing capacity, fractionation capacity, and storage capacity also are significantly lower in the low-growth case.

Comparison of Natural Gas Metrics in Base Case Versus Low-Growth Case

	Base Case, 2014-2035	Base Case Average Annual	Low-Growth Case, 2014-2035	Low-Growth Case Average Annual	Average Annual Change	Average Annual Change (%)
Gas Well Completions (1000s)	307	14	248	11	-3	-19%
Oil Well Completions (1000s)	914	42	776	35	-6	-15%
Total Well Completions (1000s)	1,221	56	1,024	47	-9	-16%
Miles of Transmission Mainline (1000s)	18.6	0.8	12.6	0.6	-0.3	-32%
Miles of Laterals to/from Power Plants, Storage Fields, and Processing Plants (1000s)	17.1	0.8	11.4	0.5	-0.3	-33%
Miles of Gas Gathering Line (1000s)	303.1	13.8	253.5	11.5	-2.3	-16%
Inch-Miles of Transmission Mainline (1000s)	568	26	380	17	-9	-33%
Inch-Miles of Laterals to/from Power Plants, Storage Fields, and Processing Plants (1000s)	279	13	179	8	-5	-36%
Inch-Miles of Gathering Line (1000s)	1,095	50	923	42	-8	-16%
Compression for Pipelines (1000 HP)	4,388	199	2,884	131	-68	-34%
Compression for Gathering Line (1000 HP)	8,402	382	5,970	271	-111	-29%
Gas Storage (Bcf Working Gas)	823	37	366	17	-21	-56%
Processing Capacity (Bcfd)	34.2	1.6	24.7	1.1	-0.4	-28%
LNG Export Facilities (Bcfd)	9.3	0.4	4.0	0.2	-0.2	-57%

Comparison of Natural Gas Liquids Metrics in Base Case Versus Low-Growth Case

	Base Case, 2014-2035	Base Case Average Annual	Low-Growth Case, 2014-2035	Low-Growth Case Average Annual	Average Annual Change	Average Annual Change (%)
Miles of Transmission Mainline (1000s)	15.1	0.7	12.5	0.6	-0.1	-18%
Inch-Miles of Transmission Mainline (1000s)	220	10	181	8	-2	-18%
Pump for Transmission Mainline (1000 HP)	661	30	395	18	-12	-40%
Fractionation Capacity Built (MBOE/d)	3,326	151	2,501	114	-37	-25%
NGL Export Facility Capacity Built (MBOE/d)	1,402	64	1,022	46	-17	-27%

Comparison of Crude Oil Metrics in Base Case Versus Low-Growth Case

	Base Case, 2014-2035	Base Case Average Annual	Low-Growth Case, 2014-2035	Low-Growth Case Average Annual	Average Annual Change	Average Annual Change (%)
Oil Well Completions (1000s)	914	42	776	35	-6	-15%
Miles of Crude Oil Gathering Line (1000s)	171.6	7.8	149.1	6.8	-1.0	-13%
Miles of Transmission Mainline (1000s)	16.2	0.7	10.2	0.5	-0.3	-37%
Miles of Crude Oil Storage Laterals (1000s)	0.8	0.0	0.4	0.0	-0.0	-43%
Inch-Miles of Crude Oil Gathering Line (1000s)	379	17	331	15	-2	-13%
Inch-Miles of Transmission Mainline (1000s)	432	20	293	13	-6	-32%
Inch-Miles of Crude Oil Storage Laterals (1000s)	14	1	8	0	0	-43%
Pump for Transmisson Mainline (1000 HP)	3,505	159	2,020	92	-67	-42%
Crude Storage Capacity Built (MMBbl)	133	6	77	3	-3	-42%
Number of Crude Storage Tanks Built	26,504	1,205	15,362	698	-506	-42%
Number of Crude Storage Farms Built	39	2	22	1	-1	-43%

Results of Economic Impact Analysis

Robust levels of midstream infrastructure will create many positive economic effects. As part of this work, an economic impact analysis has been completed using IMPLAN, a widely recognized economic modeling platform. Based on that analysis, the economic benefits resulting from the base case are summarized as follows:

- The projected investment of $641 billion for midstream infrastructure yields an annual average of roughly 432,000 jobs across the United States and Canada throughout the projection period.[11,12]
- The cumulative 2014 through 2035 midstream investments are estimated to create $588 billion in labor income (including wages and benefits) at an average of roughly $61,800 per job across all affected industries.[13]
- The cumulative 2014 through 2035 midstream investments across the United States and Canada are estimated to contribute roughly $885 billion in value added. Value added for a firm is its sales revenue less the costs of goods and services purchased. The sum of the value added in all industries is the gross domestic product (GDP), or the total value of all final goods and services produced in the nation.
- From 2014 through 2035, total state/provincial and local taxes generated from midstream development will be roughly $146 billion, and total federal tax revenues will be roughly $156 billion across the United States and Canada.

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[11] The annual average job figures used in this study are calculated as the total job-years created during the study period as determined by IMPLAN, divided by the years in the study period. IMPLAN's glossary of terms defines a job as the annual average of monthly jobs in that industry, but also points out that this can be one job lasting 12 months, two jobs lasting 6 months each, or three jobs lasting 4 months each, and also explains that a job can be either full time or part time. The totals represent all jobs calculated by IMPLAN, including direct, indirect, and induced jobs.

[12] The jobs discussed here include those necessary to manufacture and construct infrastructure, and the indirect and induced jobs linked to that process. They do not include jobs that would be necessary to operate and maintain the new infrastructure because O&M costs were not considered in the infrastructure analysis discussed earlier.

[13] Labor income includes all forms of employment income, including employee compensation (wages and benefits) and proprietor income.

Economic Effects of Midstream Infrastructure Development in the Base Case: Employment, Wages, Value Added, and Taxes for the United States and Canada

Type of Effect	Employment (Jobs per Year)	Annual Wages and Benefits (2012$ per Job)	Labor Income (Billions of 2012$)	Value Added (Billions of 2012$)	State/Provincial and Local Tax Revenues (Billions of 2012$)	Federal Tax Revenues (Billions of 2012$)
United States						
Direct	112,423	$75,366	$186.4	$227.6		
Indirect	91,778	$64,114	$129.5	$208.0		
Induced	133,495	$48,875	$143.5	$256.6		
Total	**337,695**	**$61,836**	**$459.4**	**$692.2**	**$108.5**	**$132.9**
Canada						
Direct	31,603	$74,878	$52.1	$63.2		
Indirect	25,521	$63,909	$35.9	$57.6		
Induced	37,663	$48,731	$40.4	$72.2		
Total	**94,787**	**$61,535**	**$128.3**	**$193.0**	**$37.8**	**$23.3**
United States and Canada						
Direct	144,026	$75,259	$238.5	$290.7		
Indirect	117,298	$64,070	$165.3	$265.6		
Induced	171,158	$48,844	$183.9	$328.8		
Total	**432,482**	**$61,770**	**$587.7**	**$885.2**	**$146.3**	**$156.2**

Even the low-growth case projects significant economic benefits for the United States and Canada. The benefits created in the case are in line with the level of investment that, as discussed earlier, is 27 percent below the base case level of investment. The economic impact analysis for the low-growth case projects that an average of roughly 312,000 jobs will be needed to complete midstream infrastructure development, and the level of development will yield roughly $640 billion in value added for the United States and Canada over the projection period. Federal, state/provincial, and local taxes for the low-growth case total almost $220 billion over the projection period versus the base case total of more than $300 billion. While each of these measures are 20 percent to 30 percent below base case values, they are still very significant, showing the importance of midstream infrastructure development for the U.S. and Canadian economies, even in the lower growth environment that is depicted in this scenario.

Economic Effects of Midstream Infrastructure Development in the Low-Growth Case: Employment, Wages, Value Added, and Taxes for the United States and Canada

Type of Effect	Employment (Jobs per Year)	Annual Wages and Benefits (2012$ per Job)	Labor Income (Billions of 2012$)	Value Added (Billions of 2012$)	State/Provincial and Local Tax Revenues (Billions of 2012$)	Federal Tax Revenues (Billions of 2012$)
United States						
Direct	82,076	$75,559	$136.4	$166.9		
Indirect	67,315	$64,146	$95.0	$152.6		
Induced	97,172	$48,947	$104.6	$187.1		
Total	**246,563**	**$61,955**	**$336.1**	**$506.5**	**$79.3**	**$97.1**
Canada						
Direct	21,732	$75,442	$36.1	$43.9		
Indirect	17,762	$64,080	$25.0	$40.2		
Induced	25,736	$48,913	$27.7	$49.5		
Total	**65,230**	**$61,882**	**$88.8**	**$133.6**	**$26.2**	**$16.1**
United States and Canada						
Direct	103,808	$75,534	$172.5	$210.7		
Indirect	85,077	$64,132	$120.0	$192.8		
Induced	122,908	$48,940	$132.3	$236.6		
Total	**311,793**	**$61,940**	**$424.9**	**$640.1**	**$105.5**	**$113.2**

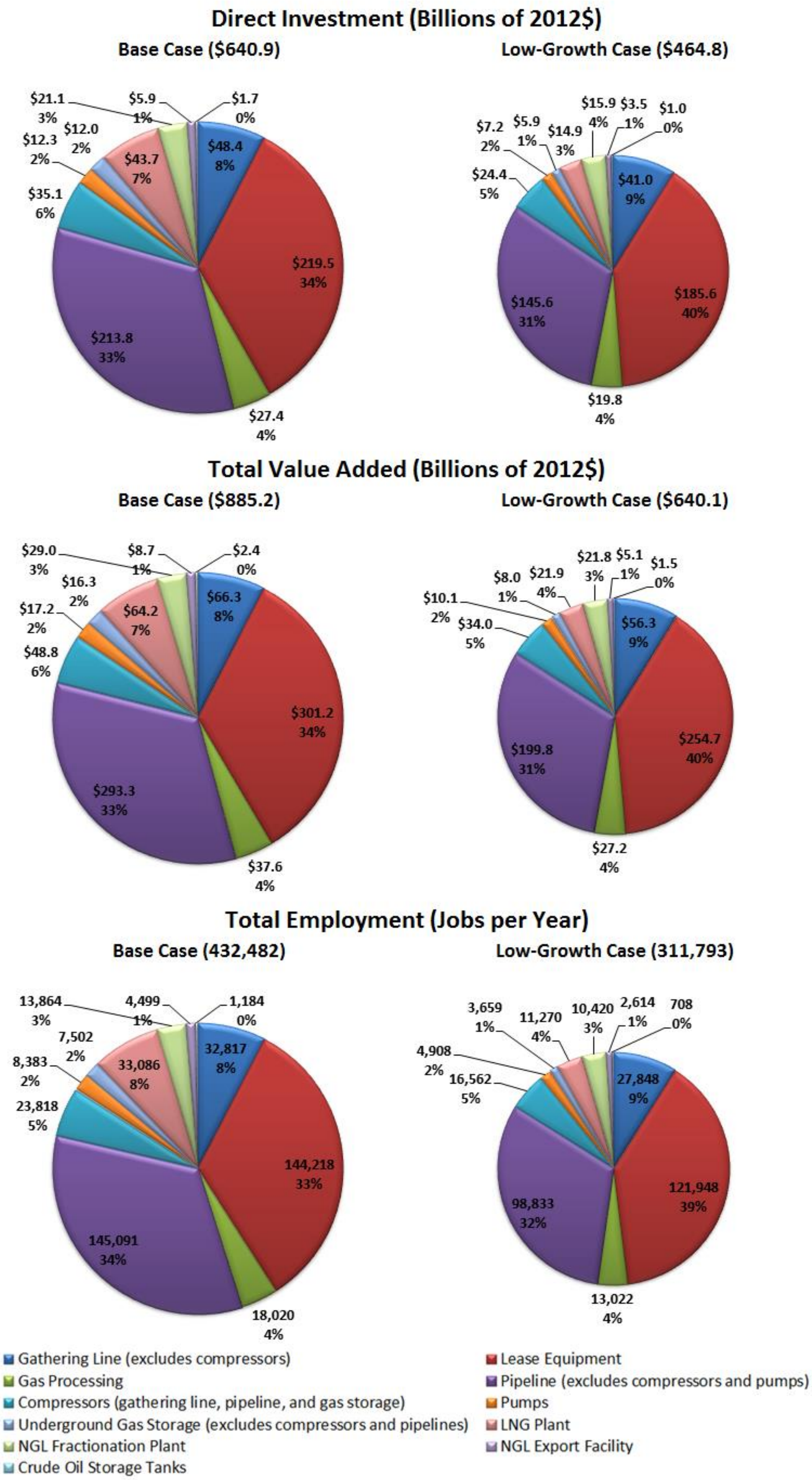
By infrastructure category, investment and employment levels will be most significant for development of lease equipment and pipelines, with roughly two-thirds of the total investment and employment concentrated in these two categories in both the base case and the low-growth case. In each of the cases, the jobs associated with constructing and deploying lease equipment hold a slight edge over the jobs associated with manufacturing and building pipelines. However, the total jobs in each of these categories are not much different, making the two categories almost equally important in the projection. Outside of these categories, employment in other categories is proportionate to the investment levels projected in the cases and, collectively, there are thousands of jobs and value added spread across the range of infrastructure that is developed in the projections.

By major industry, more than half of the jobs associated with midstream infrastructure development will occur in the services and other category. This is a consistent finding across each of the cases. This category includes a significant number of induced jobs in services outside of the energy business, including hotels, restaurants, and merchandise providers. However, companies directly involved in the development of midstream infrastructure also will see a significant number of jobs because the number of jobs concentrated in manufacturing and construction of the infrastructure and in oil, gas, and mining operations that are directly associated with developing the assets is significant. There are more than 140,000 jobs directly involved in the development of the infrastructure in the base case, and the majority of those jobs are in construction and manufacturing. The low-growth case shows a similar result. The data, while showing a heavy concentration of labor and value directly attributed to development of the assets, also shows that the economic benefits of midstream infrastructure development are widespread across all industries.

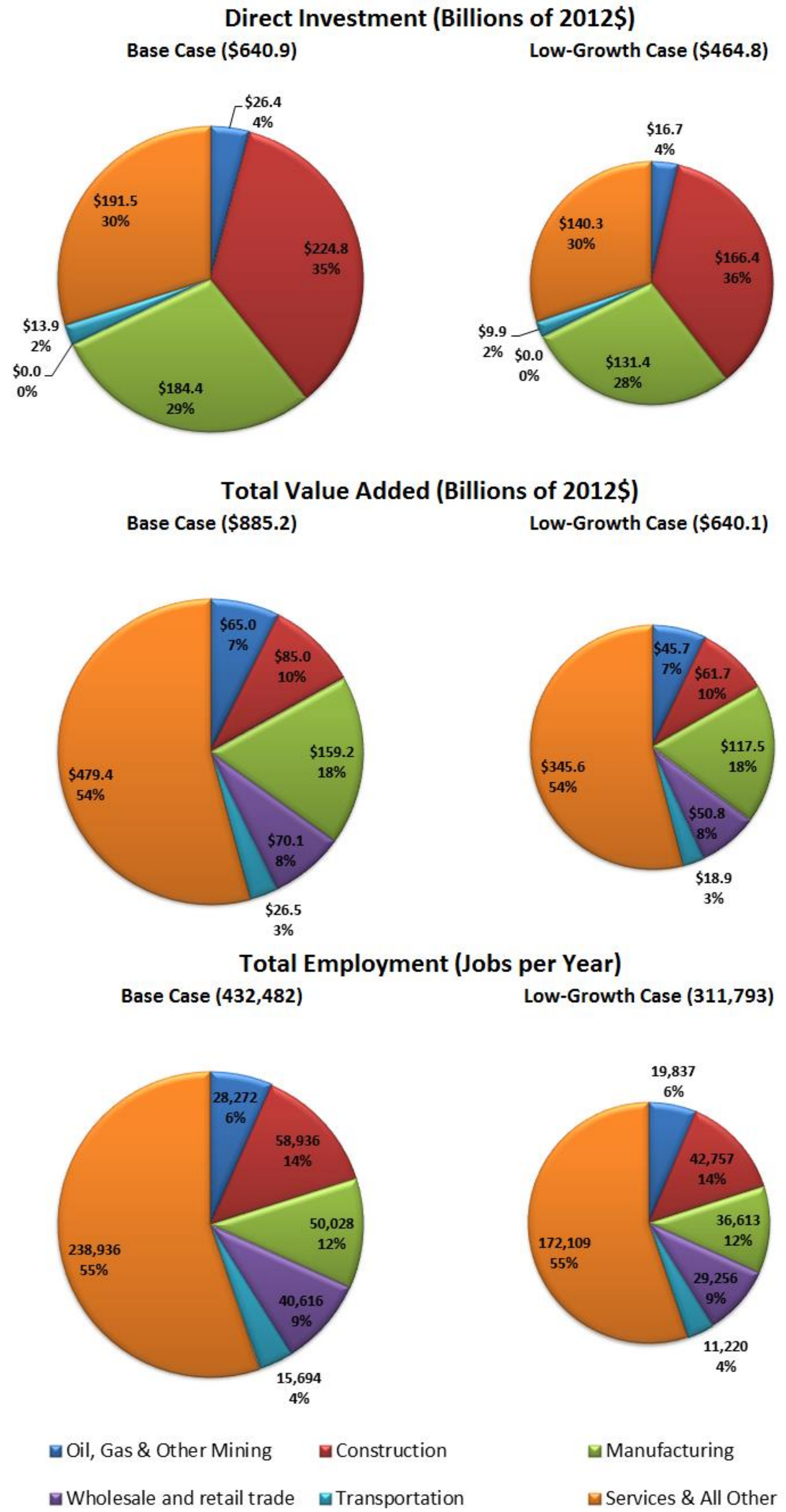
Almost half of the jobs associated with midstream development are concentrated in the southwestern United States and in Canada. There are more than 200,000 jobs concentrated in these areas in the base case, compared with almost 150,000 jobs in these areas in the low-growth case. These areas have been home to significant midstream development historically, so it is not a surprise that the areas account for many of the jobs needed for the development of new infrastructure in the future. The northeastern United States, home to Marcellus and Utica development, ranks third in total employment associated with midstream development. Thus, the economic benefits of midstream infrastructure development are geographically widespread and not necessarily concentrated in any single area of the United States and Canada. In part, this is because there are many induced jobs, just over 170,000 jobs in the base case and 120,000 in the low-growth case that are somewhat related to population distribution across the United States and Canada. Regional value added is proportionate to both the level of investment in infrastructure and jobs, so the three measures are a direct function of where the investment is geographically concentrated over time.

The bottom line of the economic impact analysis is that the substantial midstream infrastructure development that is projected in the cases creates significant economic benefits for the United States and Canada over time. In practical terms, every $100 million in investment in new infrastructure creates an average of about 67 jobs over the projection period and adds roughly $138 million in value to the U.S. and Canadian economies. Furthermore, as sector and geographic results show, job impacts and value added cross all parts of the economy and are geographically widespread.

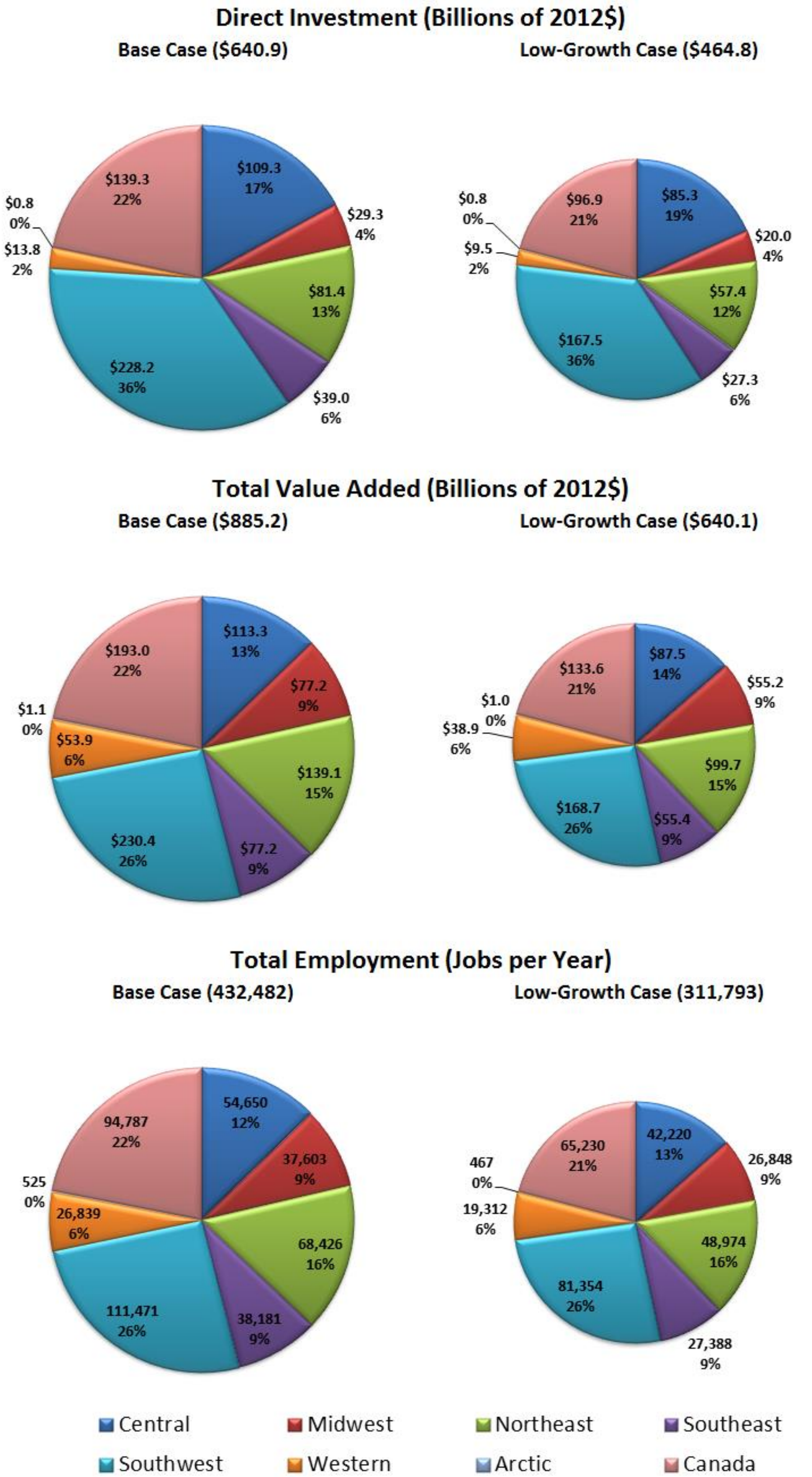
Economic Effects by Infrastructure Category, Base Case versus Low-Growth Case, 2014-2035



Economic Effects by Industry Sector, Base Case versus Low-Growth Case, 2014-2035



Economic Effects by Region, Base Case versus Low-Growth Case, 2014-2035



Conclusions

The main conclusions in this study are summarized below:

- Significant infrastructure will be needed to support growing gas use. The base case, which assumes $100 per barrel of oil and shows gas prices rising from $4 per MMBtu to an average of $6 per MMBtu in the longer term, and is considered a middle-of-the-road scenario.
- The base case projects significant supply development and growth in gas production, primarily from shale resources. Producers are likely to develop shale plays with large quantities of oil and NGL, which also have significant needs for new pipeline infrastructure.
- The base case projects substantial NGL production growth, especially from the Marcellus and Utica shale plays in the northeastern United States and also from other liquid-rich plays in the United States and Canada. A significant number of gas processing, pipeline, and fractionation facilities are required to accommodate growing NGL production.
    - NGL produced in the northeastern United States from Marcellus and Utica shale seek established petrochemical markets along the Gulf Coast.
    - Alberta oil sands have an increasing need for pentanes-plus NGL to dilute bitumen, aiding the transport of it through oil pipelines.
    - Bakken and Central Rockies NGL flow to the Gulf Coast through West Texas. Flows of raw NGL from West Texas to the Gulf Coast are projected to double by 2035.
    - The base case also projects significant growth of NGL exports from the Gulf Coast and Western Canada.
- The base case projects robust growth of crude oil and condensate production, mostly from Alberta oil sands and tight/shale oil plays, driven by relatively high oil prices. A significant number of pipeline expansions and new pipelines are under development, and incremental transport capability is needed to accommodate growing crude oil and condensate production.
    - Alberta oil sands production is projected to nearly triple by 2035. Bakken shale crude oil production will double by 2020 to almost 1.8 million BPD and increase to 2.1 million BPD by 2035. Significant crude production growth is also expected from West Texas and Gulf Coast tight/shale plays.
    - Exports off of the West Coast of Canada will increase by more than 2 million BPD from 2020 through 2035.

From 2011 through 2035, the following approximate amounts of new infrastructure are required:

Natural gas infrastructure:

- Approximately 43 Bcfd in new gas transmission capability
- About 850 miles per year in new gas transmission mainline
- Over 800 miles per year in new laterals to/from power plants, processing facilities, and storage fields

- Almost 14,000 miles per year in new gas gathering lines
- Approximately 35 Bcfd of new gas processing capability
- About 37 Bcf per year in new working gas storage capacity
- More than 580,000 horsepower per year for pipeline and gathering compression
- About 9 Bcfd of new LNG export capacity

NGL infrastructure:

- About 3.6 MMBPD in new NGL transmission capacity
- Almost 700 miles per year in new NGL transmission line
- About 30,000 horsepower per year for pumping requirement for pipeline
- Approximately 151 MBOE/d in new NGL fractionation capacity is added each year
- Almost 64 MBOE/d in new NGL export capacity is added each year.

Oil infrastructure:

- More than 10 MMBPD in new oil transmission capacity
- Over 730 miles per year in new oil transmission line
- About 35 miles per year in new laterals for crude oil storage
- Approximately 7,800 miles per year in new oil gathering lines
- Over 6 MMBbl per year in new crude oil storage capacity

Expenditures for the incremental infrastructure projected here are significant:

- More than $640 billion or about $30 billion per year, in total capital expenditures are required over the next 22 years for the combined natural gas and liquids outlook.
- $10 billion per year, or 34 percent of this amount, is required for new oil and gas lease equipment.
- Almost $9 billion, or 29 percent, is for new or expanded gas and liquids mainline capacity.
- More than $3 billion per year, or 11 percent, is needed for new oil and gas gathering lines.
- More than $2 billion per year, or 8 percent, is required for new laterals.
- Roughly $2.0 billion per year, or 7 percent, is required for new LNG export facilities.
- More than $1 billion per year, or 4 percent, is required for new processing plants.
- Roughly $1.0 billion per year, or 3 percent, is required for new NGL fractionation plants.
- The remainder, almost $1 billion per year, is for underground gas storage, crude oil storage, and NGL export facilities.

This study includes additional new facilities that were not included in the 2011 study:

- These facilities include compression for gas gathering lines, crude oil gathering lines, crude oil storage and laterals, NGL fractionation, NGL export facilities, oil and gas lease equipment, and LNG export facilities.
- These additional facilities account for almost $300 billion, or more than 45 percent of the total expenditure.

Even the low-growth case shows substantial need of new midstream infrastructure:

- Total midstream expenditures projected in the low-growth case are $465 billion, 27 percent lower than the reference case.
    - Even with lower projected oil prices and lower economic growth in the low-growth case, the expenditures for midstream infrastructure requirements are still very significant.
    - Reductions in expenditures are generally similar on a percentage basis across many of the infrastructure categories.

The economic benefits of midstream infrastructure development are significant:

- Based on IMPLAN analysis, the base case projects that an average of roughly 432,000 jobs will be needed to accomplish the levels of infrastructure development that occur in the case. The development of the infrastructure will yield a value added of roughly $885 billion to the U.S. and Canadian economies, and federal, state/provincial, and local taxes totaling roughly $300 billion.
- As a practical example of this, every $100 million of investment in new infrastructure creates an average of about 67 jobs over the projection period and adds roughly $138 million in value to the U.S. and Canadian economies.
- The low-growth case, while yielding values that are between 20 percent and 30 percent below the base case values, still provides substantial economic benefits to the U.S. and Canadian economies over time.
- While many of the economic benefits accrue directly to companies active in midstream development, there are many indirect and induced benefits that occur in many other industries, and a substantial number of service sector jobs are created as a result of the midstream development.
- Although many of the economic benefits are concentrated in areas where midstream development has been historically prevalent, the benefits are geographically widespread. All sectors and regions of North America benefit from the infrastructure development.