# North America Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance

Prepared by ICF International for
The INGAA Foundation, Inc.

Support provided by America's Natural Gas Alliance

The INGAA Foundation, Inc.

## Detailed Study Methodology and Results

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# Disclaimer

# Contents (Grayed out sections are available upon request)

# Study Overview

# Study Objectives

- The objective of this study is to estimate future midstream infrastructure requirements, including natural gas, natural gas liquids, and oil infrastructure requirements through 2035.
  - Study is based on a detailed supply/demand outlook for North American energy markets.
  - In the context of this analysis, the midstream includes:
    - Natural gas gathering and lease equipment, processing, pipeline transportation and storage, and LNG export facilities.
    - Natural gas liquids (NGLs) pipeline transportation, fractionation, and NGL export facilities.
    - Crude oil gathering and lease equipment, pipeline transportation, and storage facilities.
  - A Low Growth Case is also considered.
  - Study provides an update to the INGAA Foundation's 2011 infrastructure study.
- Study also analyzes the impacts of midstream infrastructure investments on jobs and the economy.
- Study has been initiated to more fully consider recent trends and investigate the impacts of those trends, particularly robust shale gas and tight oil development, on future infrastructure requirements.

# Scope of Work

- This study projects natural gas and liquids infrastructure requirements, by:
  - Considering regional natural gas supply/demand projections that rely on the most current market trends.
  - Considering well completion and production information across major supply areas.
  - Considering gas processing requirements by region.
  - Considering how power plant gas use is likely to change in the future.
  - Reviewing underground natural gas storage requirements by region.
  - Completing an analysis of NGL and oil infrastructure requirements by applying well and production information across major supply areas.
  - Considering a number of new gas uses and additional types of infrastructure that were not considered in the 2011 study (discussed on the next slide)
- This study assesses the economic impacts of midstream infrastructure investments, by:
  - Completing a regional impact analysis that relies on IMPLAN.
  - Considering the direct, indirect, and induced impacts of the infrastructure development.
- This study considers new infrastructure needs. It does not investigate replacement of existing infrastructure, nor does it investigate operations and maintenance of existing infrastructure.

# Similarities to and Differences from the 2011 Study

- Even though this study projects a lower number of gas wells, versus the 2011 study, shale gas production growth is still robust and it continues to yield significant development of natural gas infrastructure.
  - But, the current slate of gas transportation projects generally require less miles of pipe and rely to a greater extent on using existing infrastructure in different ways - for example, adding compression to increase line capacity and reversing lines to accommodate growth from new production areas.
  - Even though less miles of pipe are required, investment in new gas pipelines is close to estimates from the prior study because line costs have continued to rise over the past few years.
- Oil and NGL production growth is projected to be much greater, leading to increased infrastructure needs for oil and NGL processing, transport, and storage.
  - This study considers repurposing of gas infrastructure for transport of oil and NGLs.
- Some production projections for various regions have increased, for example Marcellus gas production is much greater in this current study, leading to more pronounced midstream development within and from that area.
- Beyond differences mentioned above, this study also projects much greater investment and job impacts for new infrastructure because some types of activity that were overlooked in the 2011 study are now considered, including:
  - LNG exports, NGL fractionation, Mexican exports, compression in gas gathering systems, crude oil gathering line and pumping needs, oil storage, and lease equipment requirements.

# Study Methodology

- Study relies on ICF's December 2013 Base Case provided by ICForecast Subscription Service for market and supply projections.

- The case projects market changes over time, more specifically, the amount of gas used by sector and region at gas prices that are computed by ICF's Gas Market Model (GMM).
  - Changes in power generation gas use are computed, and an estimate for the number of new gas power plants is provided.
  - Changes in petrochemical gas use and LNG exports are also considered.

- The case also projects supply development and production growth that occurs at solved market prices.

- Gas production projections from the model are cross-checked with a vintage production analysis using ICF's Detailed Production Report (DPR).
  - ICF's DPR considers the number of wells, well recoveries, and representative decline curves to estimate production trends for almost 60 different supply areas.

- The GMM also projects the amount of gas transmission capacity that is likely to be developed based on the market and supply dynamics.

# Study Methodology (continued)

- From incremental gas production and well completions, the incremental amounts of gathering line and processing capacity have been computed.
  - Gathering line estimates have been derived based on the number of wells, the initial and average production from the wells and well spacing, and by assuming an average mileage of line per well (0.3 miles/well for gas wells and 0.25 miles/well for associated gas from oil wells).
  - Processing plant capacity is computed based on the average production of wells and the characteristics of the production stream.
    - Processing plants requirements are estimated by assuming average plant sizes that are area dependent.
    - The number of pipeline laterals needed and the associated pipeline mileage is derived for processing plants.
- Number of pipeline laterals and the associated pipeline mileage are derived for gas power plants.
- Horsepower requirements are derived separately for each transmission project.
- Storage capacity is added based on market and supply growth and by considering seasonal price spreads.
- Unit cost measures have been derived for pipeline and gathering ($/inch-mile), horsepower ($/HP), processing capacity ($/MMcfd), and storage ($/Bcf) based on historical expenditure information provided by various sources.
- Unit cost measures are applied to estimate total expenditures for midstream infrastructure.

# Study Methodology (continued)

- Crude oil and natural gas liquids (NGLs) production projections are computed in ICF's Detailed Production Report (DPR).

- The crude oil and NGL pipeline transmission capacity projection is determined by using ICF's Crude Oil Transport Model and ICF's NGL Transport Model, respectively.
  - The Crude Oil Transport Model considers pipeline, rail, truck, and tanker transport of crude oil between 32 regions and over 240 network links in the U.S. and Canada.
  - NGL Transport Model considers pipeline, rail, and truck transport of raw and purity NGLs between 27 regions and over 200 network links in the U.S. and Canada.
  - Pipeline capacity is added based on potential supply and market growth and considering export assumptions.

# Study Methodology (continued)

- Additional information added in the current study (not considered in the 2011 analysis):
  - Compression for gas gathering lines
  - Compression for gas storage fields
  - Crude oil gathering lines
  - Crude oil storage and related pipeline laterals
  - NGL fractionation capacity
  - NGL export facilities
  - Oil and gas lease equipment
  - LNG export facilities

- Compression for gas gathering lines:
  - Compression requirements for gas gathering lines are computed based on a historical average (141 HP/MMcfd), obtained from various sources, and considering gas production growth by region.

- Compression for gas storage fields:
  - Compression requirements for gas storage fields are computed based on a historical average by storage type obtained from various sources. The compression requirements are 1,880 HP/Bcf for salt cavern storage, 610 HP/Bcf for depleted reservoir storage, and 1,200 HP/Bcf for aquifer reservoir storage.

# Study Methodology (continued)

- Crude oil gathering lines:
  - Oil gathering line connections are considered for high productivity oil wells.
    - A minimum initial production cutoff (20 barrels per day of production) is assumed to differentiate high productivity wells from low productivity wells.
    - Low productivity wells do not require gathering line as oil production is handled by using local storage and trucks.
    - Expenditures for new trucks are not considered.
  - Oil gathering line estimates have been derived based on the number of oil wells assuming an average mileage of line per well (0.25 miles/well).

- Crude oil storage and related pipeline laterals:
  - Crude oil storage capacity is added based on production growth.
    - Number of crude oil tanks is computed based on storage capacity and assuming an average tank size of 5,000 barrels.
    - Number of tank farms is computed based on an average of 750 tanks per farm in the U.S. and 500 tanks per farm in Canada.
  - The number of laterals needed for the new oil storage capacity and the associated pipeline mileage is based on average miles of laterals per tank farm (20 miles per tank farm).

- NGL fractionation capacity:
  - NGL fractionation capacity is added based on NGL production growth.
  - Capacity cost is computed by applying an average unit cost ($/BOE) based on historical expenditure information provided by various sources.

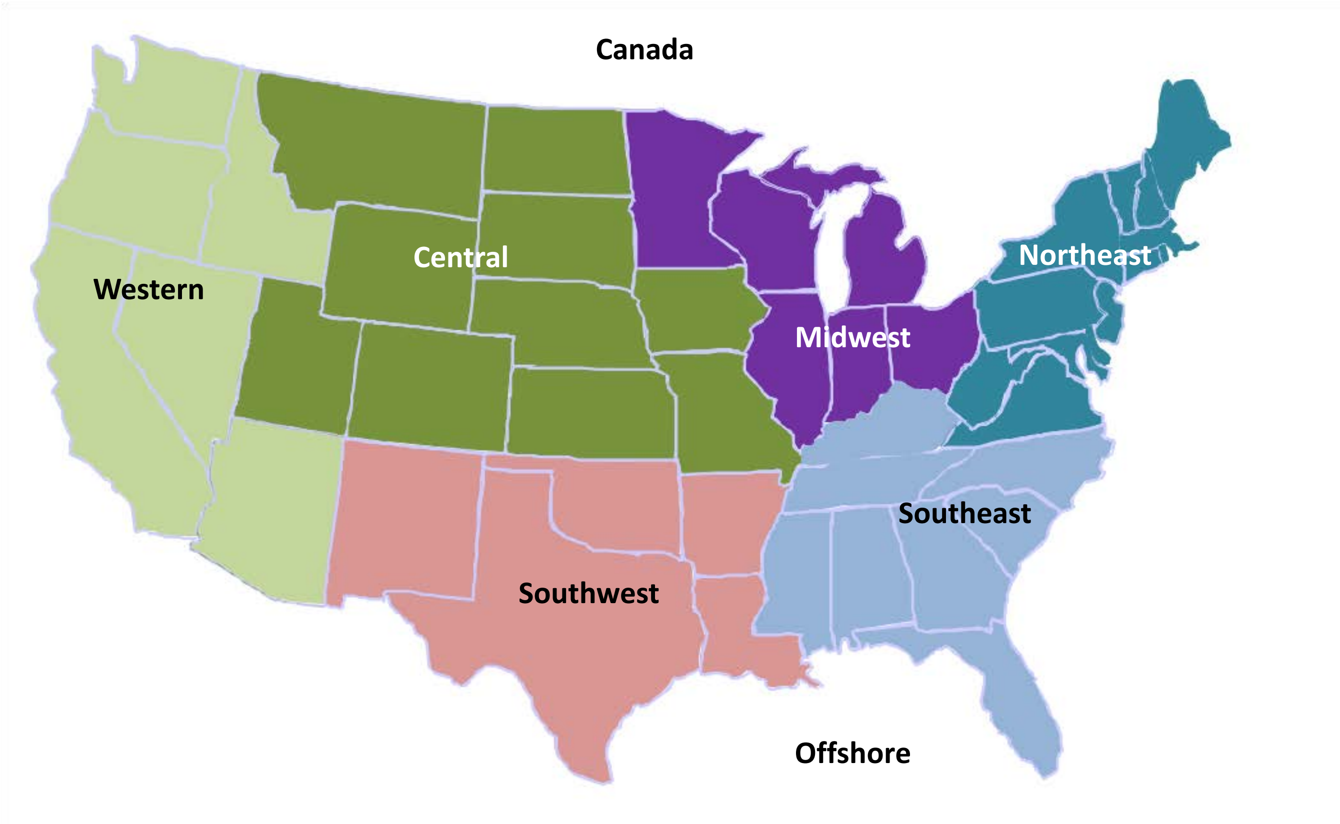
# Study Methodology (continued)

- NGL export facilities:
  - Capacity cost is computed by applying an average unit cost ($/BOE) based on historical expenditure information provided by various sources.
- LNG export facilities:
  - Capacity and costs of LNG export facilities have been obtained from DOE export applications and public sources.
    - The Base Case assumes a total of 9.3 Bcfd of LNG exports from the U.S. and Canada. Current export applications, however, are much greater.
- Oil and gas lease equipment:
  - Lease equipment for oil wells includes accessory equipment, the disposal system, electrification, flowlines, free water knockout units, heater treaters, LACT units, manifolds, producing separators, production pumping equipment, production pumps, production valves and mandrels, storage tanks, and test separators.
  - Lease equipment for gas wells includes dehydrators, disposal pumps, electrification, flowlines and connections, the production package, production pumping equipment, production pumps, and storage tanks.
  - Lease equipment cost estimates have been derived based on cost per well ($/well) that is area/play dependent, derived from EIA Oil and Gas Lease Equipment and Operating Costs data.
  - The oil and gas lease equipment is assumed to have a life span of 20 years.

# Categories of Pipeline Characterized in Study

- Natural Gas Mainline Pipe
  - New Line – New Greenfield
  - New Line - Extensions
  - Expansion - Looping & Compression
  - Expansion - Compression Only
  - Expansion - Reversal or Repurposing
- Lateral Pipe
  - Power Plant Laterals
  - Gas Storage Field and Oil Storage Tank Laterals
  - Gas Processing Plant Laterals
  - Fractionation Plant Laterals
  - Other Laterals (delivery or receipt area laterals)
- Gathering Pipe for Oil and Gas Wells
- Natural Gas Liquids (NGL) Mainline Pipe
- Oil Mainline Pipe

# Study Regions




Includes EIA's pipeline regions with regions added for Offshore Gulf of Mexico, Canada, and Arctic (Alaska and NWT). This is the same regional format as used in the INGAA 2009 and 2011 Infrastructure Studies.

# Modeling and Cost Assumptions

# Assumptions for the Base Case

- U.S. GDP assumed to grow at 2.6% per year, Canadian GDP grows at 2.5% per year, and population grows at approximately 1% per year after 2014.

- Roughly 4,000 trillion cubic feet (Tcf) of recoverable gas resource. Abundant and cost effective tight oil supplies spread across the U.S. and Canada, and vast amount of oil sands resource in Western Canada.

- Oil prices of $100 per barrel in Base Case continues to drive "oil-gas price arbitrage" investments. LNG exports, and petrochemical activities, including ammonia production, ethylene production, and propylene production fair well in this environment.
  - U.S. and Canada LNG exports approach 9 billion cubic feet per day (Bcfd) by 2022.

- Relatively high oil price continues to spur oil and NGL focused production activities.

- Electric load growth averages 1.3% per year and coal plant retirements of roughly 60 Gigawatts (GW) in the U.S. and Canada drive interest in gas-fired power generation.

- Midstream infrastructure development driven by supply and demand trends, and assumed to not be a constraining or limiting factor on market development.
  - Projects under construction are completed, and projects planned for development are implemented in response to market needs.

# The North American Natural Gas Resource Base Could Support Current Levels of Gas Use for About 150 Years

- In total, the U.S. and Canada have over 4,000 Tcf of resource that can be economically developed using current exploration and production (E&P) technologies.
  - At current levels of consumption, this is enough resource for about 150 years.
  - As technologies improve and new discoveries are made, the total gas resource is likely to grow.
- Over 50% of the assumed resource is shale gas.

## U.S. and Canada Natural Gas Resource Base[1]

**(Tcf of Economically Recoverable Resource, Assuming Current E&P Technologies)**

| | Proven Reserves | Unproved Plus Discovered Undeveloped | Total Remaining Resource | Shale Resource[2] |
|---|---|---|---|---|
| Alaska | 9.4 | 153.6 | 163.0 | 0.0 |
| West Coast Onshore | 2.9 | 24.6 | 27.5 | 0.3 |
| Rockies & Great Basin | 81.8 | 388.3 | 470.1 | 37.9 |
| West Texas | 20.4 | 47.7 | 68.1 | 17.5 |
| Gulf Coast Onshore | 97.6 | 684.7 | 782.3 | 476.9 |
| Mid-continent | 65.3 | 205.0 | 270.3 | 133.9 |
| Eastern Interior [3,4] | 45.2 | 1,053.7 | 1,098.9 | 986.1 |
| Gulf of Mexico | 10.7 | 238.6 | 249.3 | 0.0 |
| U.S. Atlantic Offshore | 0.0 | 32.8 | 32.8 | 0.0 |
| U.S. Pacific Offshore | 0.8 | 31.7 | 32.5 | 0.0 |
| WCSB | 68.8 | 664.0 | 732.8 | 508.8 |
| Arctic Canada | 0.0 | 45.0 | 45.0 | 0.0 |
| Eastern Canada Onshore | 0.8 | 15.9 | 16.7 | 10.3 |
| Eastern Canada Offshore | 0.3 | 71.8 | 72.1 | 0.0 |
| Western British Columbia | 0.5 | 10.9 | 11.4 | 0.0 |
| US Total | 334.1 | 2,860.6 | 3,194.7 | 1,652.5 |
| Canada Total | 70.4 | 807.6 | 878.0 | 519.1 |
| US and Canada Total | 404.5 | 3,668.1 | 4,072.6 | 2,171.6 |

1. ICF updated its gas resource assessment in December 2011; while these regional totals may not fully reflect the current assessment, the U.S./Canada economically recoverable resource is similar.
2. Shale Resource is a subset of Total Remaining Resource
3. Eastern Interior includes Marcellus, Huron, Utica, and Antrim shale.
4. Base Case assumes drilling levels are constant at today's level over time, reflecting restricted access to the full resource development.

# Midstream Infrastructure Cost Assumptions in 2012$

- Unit costs assumed for midstream infrastructure development remain constant in real terms throughout the projection.
- Average pipeline costs are $155,000 per inch-mile, varying regionally.
  - The average cost was $94,000 per inch-mile in the 2011 Study.
- Costs for gathering lines vary by diameter.
- Compression and pumping costs are $2,600 per horsepower (HP).
- Costs for lease equipment are $88,000 per gas well and $210,000 per oil well.
- Gas processing costs (not including compression) are about $520,000 per million cubic feet per day (MMcfd).
- Costs for NGL fractionation facilities average $6,500 per barrel of oil equivalent (BOE) of NGL processed.
- Costs for NGL export facilities are purity dependent:
  - $6,200 per BOE of ethane processed,
  - $5,000 per BOE of propane processed, and
  - $5,000 per BOE of Butane processed.
- Costs for crude oil storage tanks average of $15 per barrel of oil.
- LNG export facility costs average $5-6 billion per Bcfd of export.

**Pipeline Cost Multipliers**

| Region | Regional Cost Factors |
|---|---|
| Canada | 0.80 |
| Central | 0.69 |
| Midwest | 0.85 |
| Northeast | 1.46 |
| Offshore | 1.00 |
| Southeast | 1.09 |
| Southwest | 0.68 |
| Western | 1.14 |

**Gathering Line Costs**

| Diameter (Inches) | Gathering Line Costs (2012$/inch-mile) |
|---|---|
| 1 | $46,228 |
| 2 | $34,671 |
| 4 | $28,892 |
| 6 | $24,164 |
| 8 | $25,215 |
| 10 | $39,398 |
| 12 | $68,291 |
| 14 | $110,316 |
| 16 | $122,135 |

**Compression and Pumping Multipliers**

| Region | Regional Cost Factors |
|---|---|
| Canada | 1.00 |
| Central | 1.06 |
| Midwest | 1.16 |
| Northeast | 1.24 |
| Offshore | 1.00 |
| Southeast | 1.00 |
| Southwest | 0.98 |
| Western | 1.07 |

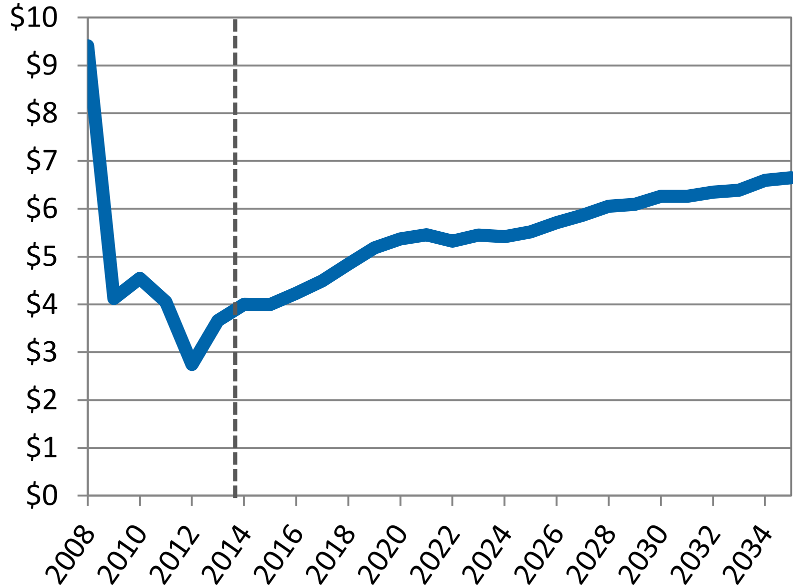
**Natural Gas Storage Costs (Millions of 2012$ per Bcf of Working Gas Capacity)**

| Field Type | Expansion | New |
|---|---|---|
| Salt Cavern | $26 | $31 |
| Depleted Reservoir | $15 | $18 |
| Aquifer | $30 | $37 |

# Summary of Base Case Trends

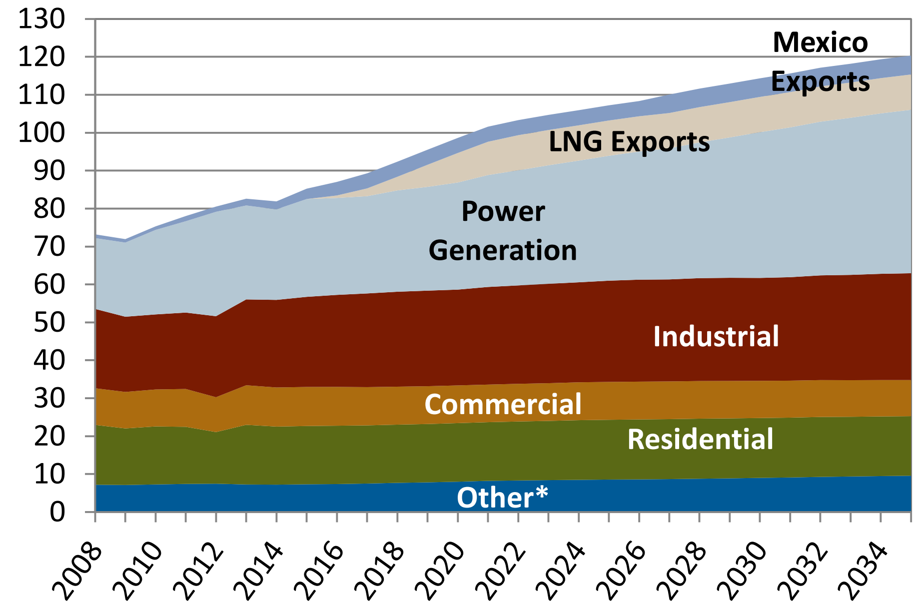
# Projected Natural Gas Price and Demand in the Base Case

**Average Annual Natural Gas Prices at Henry Hub (2012$/MMBtu)**




- Projected Henry Hub gas prices are likely to average between $5 and $6 per million British thermal unit (MMBtu) in the longer term.
- Projected gas prices are high enough to support projected supply development, but not so high as to adversely impact market growth.

**U.S. and Canadian Gas Consumption Average Annual Billion Cubic Feet per Day (Bcfd)**

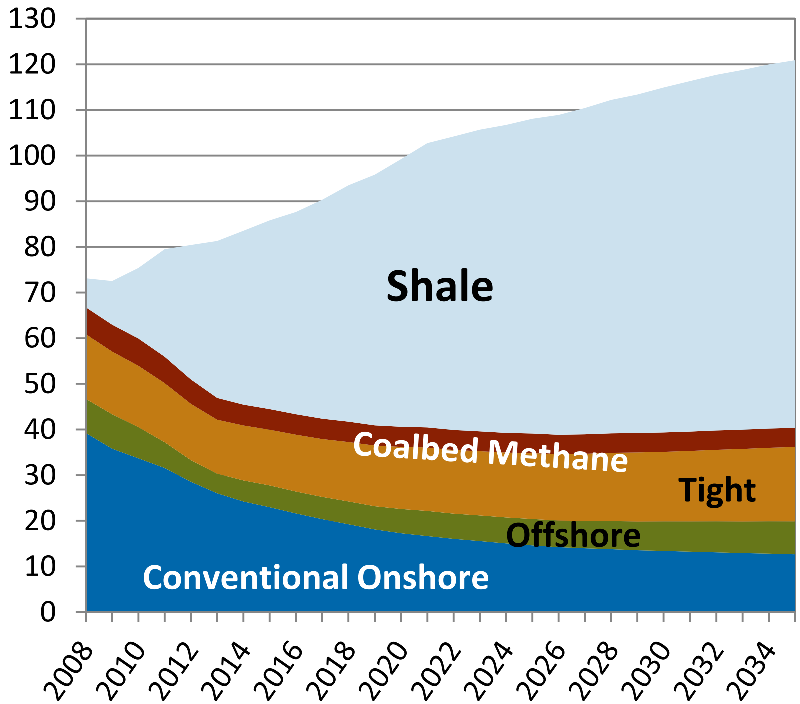



**Other includes lease, plant, and pipeline fuel gas use.*

- Total gas consumption (including exports from the U.S. and Canada) is projected to increase at a rate of 1.8% per year
  - By 2035, total gas consumption in the U.S. and Canada is projected to reach an average of almost 120 Bcfd.

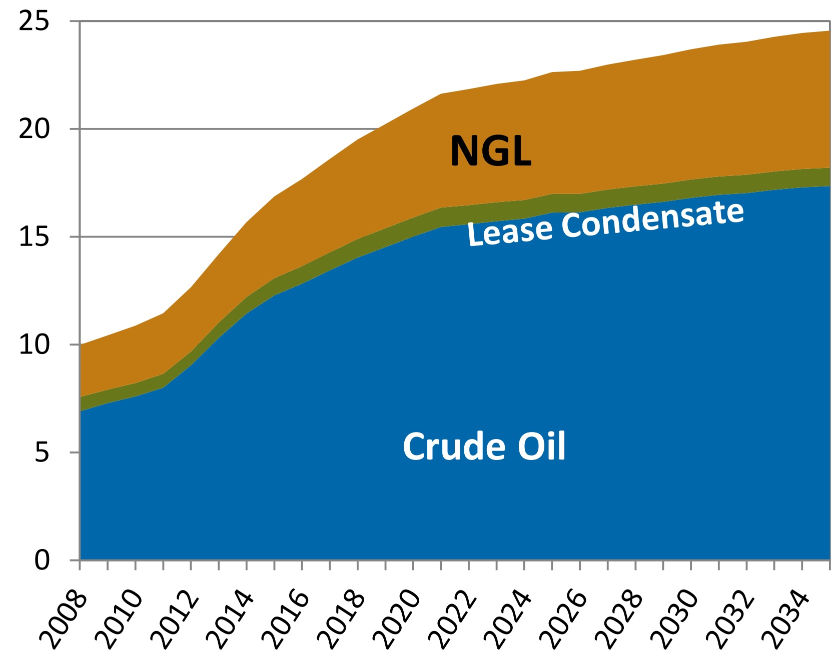
# Natural Gas, Oil, and NGL Production in the Base Case

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




- Total gas production increases by 1.8% per year, rising to over 120 Bcfd by 2035.
- Shale gas grows to two-thirds of the total production by 2035, while conventional gas production declines significantly.

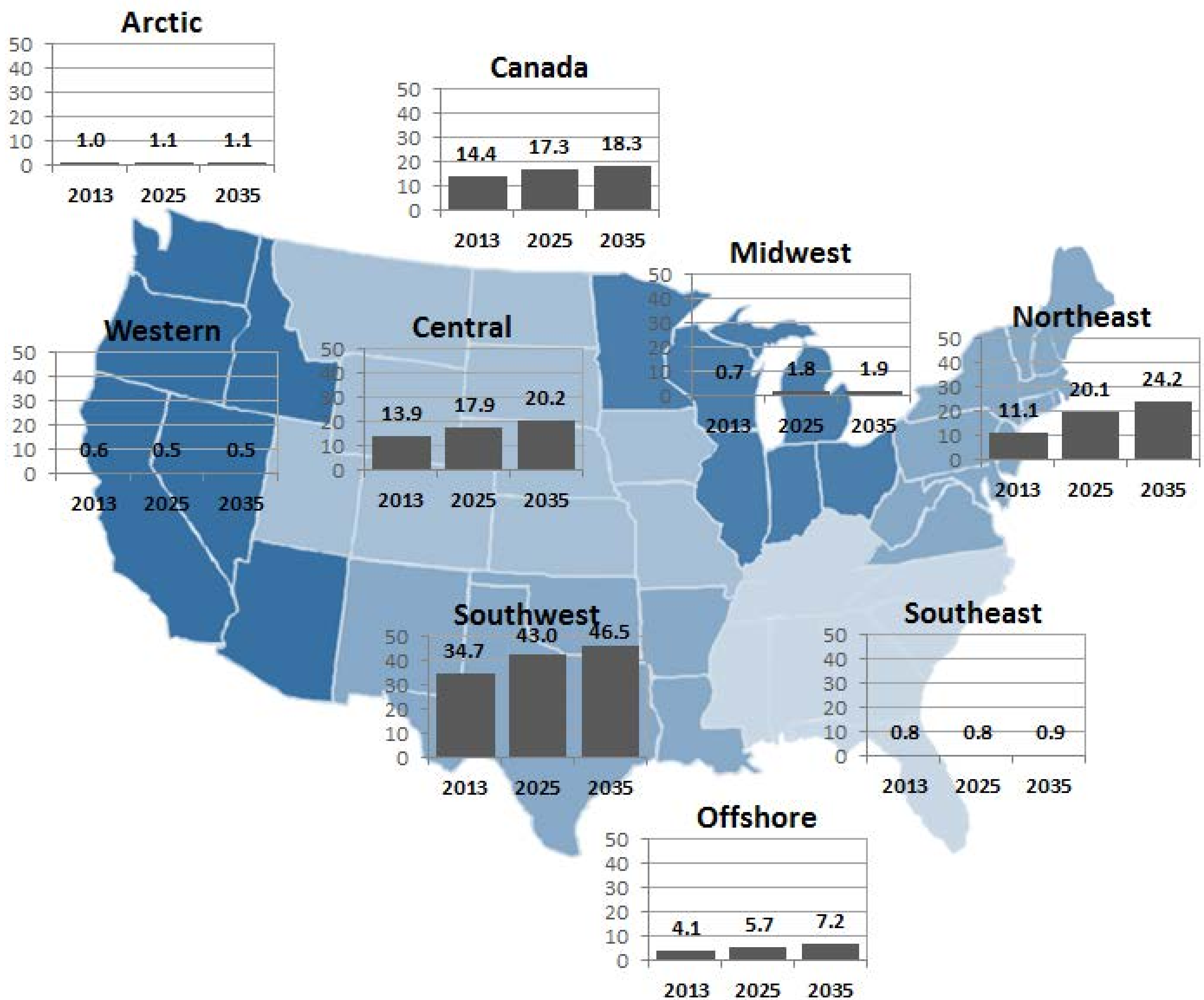
**U.S. and Canadian Liquid Production Average Annual Million Barrels per Day (MMBPD)**




- Robust crude oil and condensate production growth in the U.S. and Canada driven by relatively high oil price.
  - Oil and condensate production grows to 18.2 million barrels per day (MMBPD) or by 2.3% per year through 2035
  - Incremental production comes from Western Canada oil sands and tight oil supplies.
- NGL production in the U.S. and Canada grows by 3.2% per year, rising to roughly 6 MMBPD by 2035.

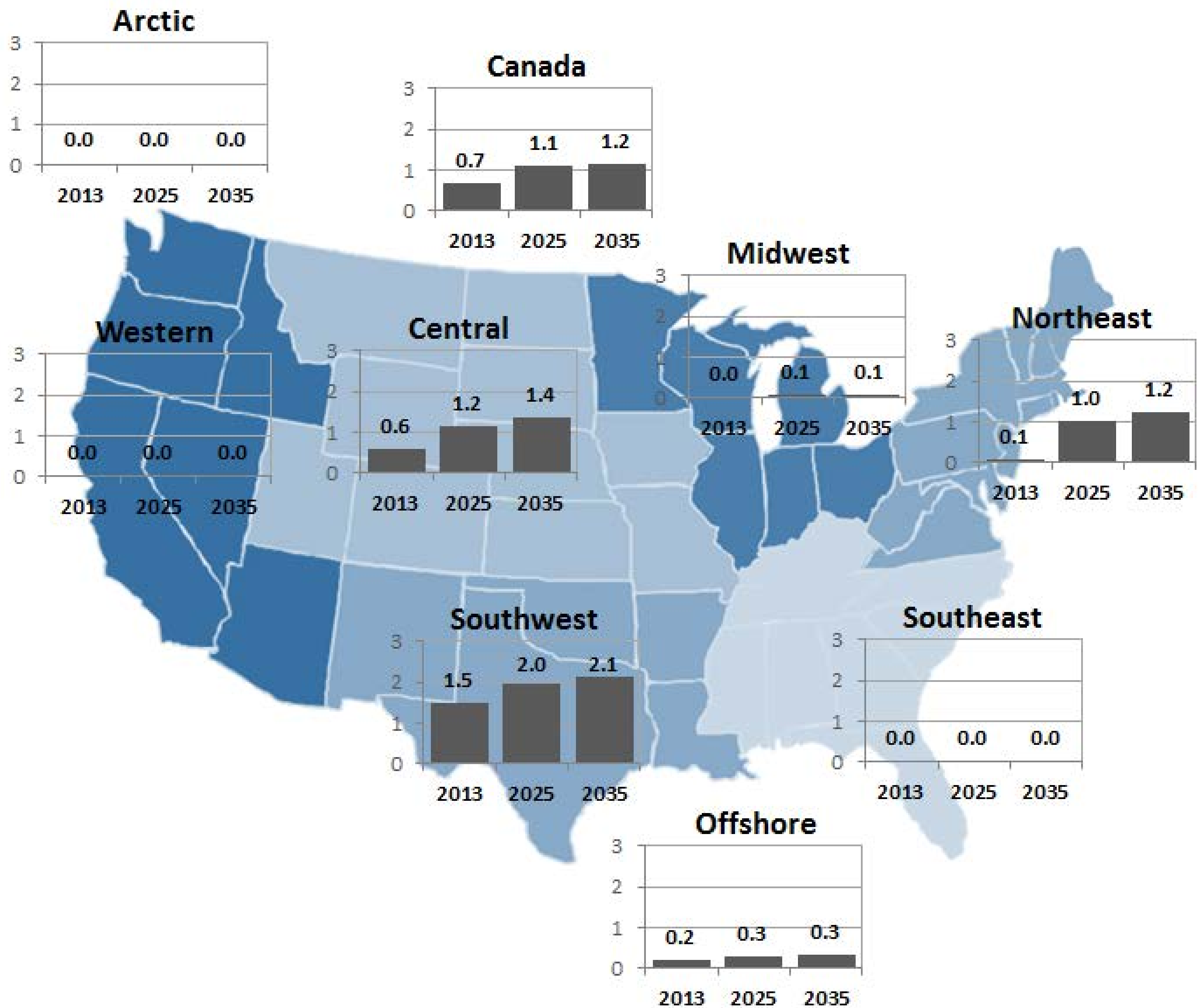
# Regional Natural Gas Production (Bcfd)

- Substantial gas production growth mostly from shale plays in the Northeast, Southwest, and Canada.
  - Northeast growth is mostly from the Marcellus Shale.
  - Growth in the Southwest is driven by production from the Haynesville and Eagle Ford shale plays.
  - Canada production growth is mostly from Horn River and Montney shale plays in British Columbia.
- Production growth in the Central region is mainly from the Rocky Mountain tight gas production and also from the Niobrara shale gas production.



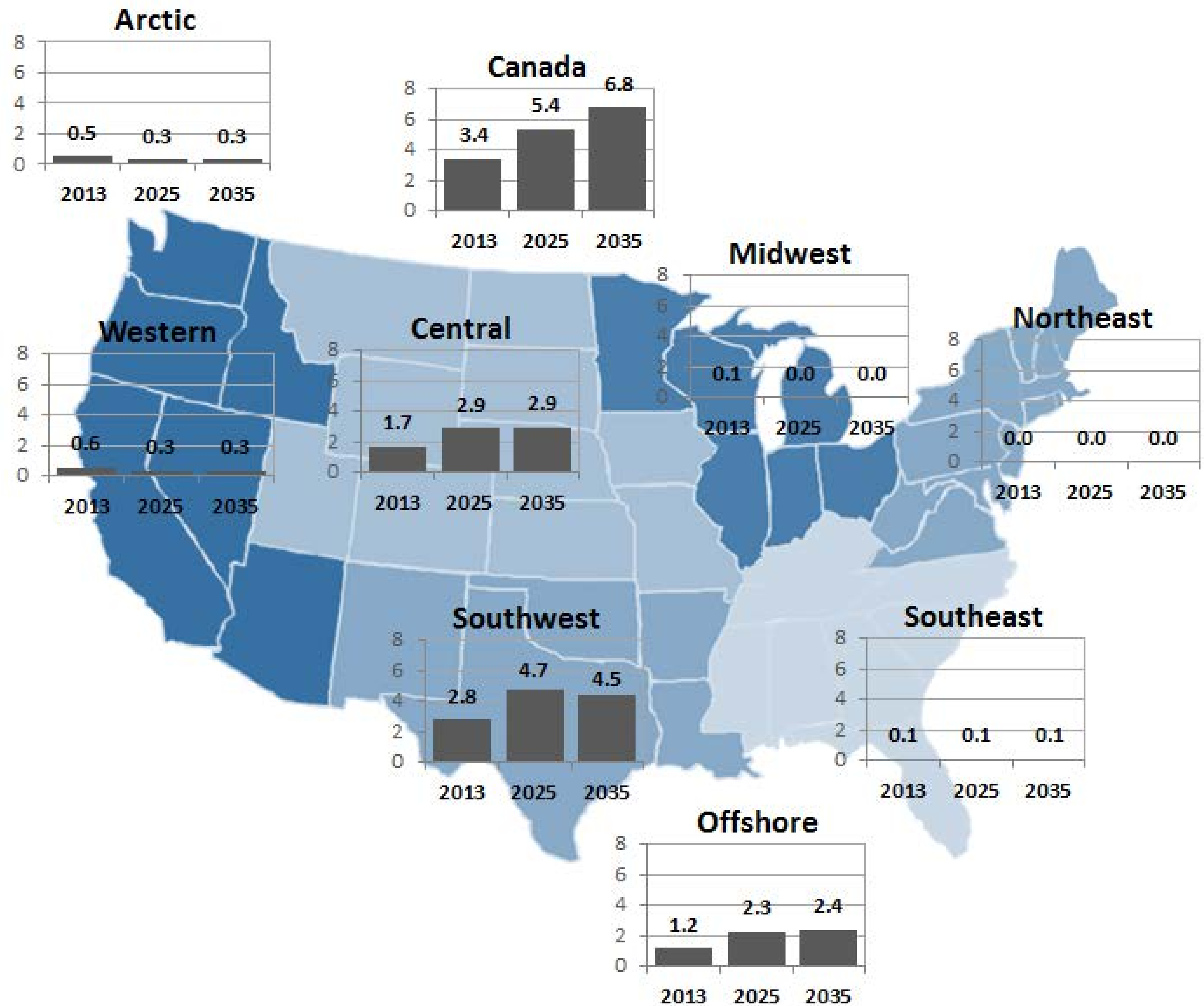
# Regional Natural Gas Liquids Production (MMBPD)

- Major NGL production growth regions include:
  - Marcellus and Utica Shales (Northeast).
  - Western Canada's Shales including the Montney, Horn River, and several smaller plays.
  - Eagle Ford Shale (Southwest).
  - Bakken Shale (Central).



# Regional Crude Oil and Lease Condensate Production (MMBPD)

- Largest production growth is from oil sands in Alberta.
- Significant production growth from shale/tight oil plays in the U.S.
  - Southwest shale/tight oil plays include the Eagle Ford and Permian basin's Wolfberry, Cline, Avalon & Bone Springs, and other smaller plays.
  - The Central region includes the Bakken, the largest single tight oil play in North America, and the Niobrara's in the Denver and Powder River basins.
- Production growth from the deepwater Gulf of Mexico is also significant.



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# Summary of Key Market Trends in Base Case (Tcf)

| U.S. and Canada | 2013 | 2025 | 2035 | % Change 2013 to 2025 | % Change 2013 to 2035 |
|---|---|---|---|---|---|
| Gas Consumption | 29.5 | 34.3 | 38.7 | 16% | 31% |
| Gas Use in Power Generation | 9.0 | 12.0 | 15.7 | 33% | 74% |
| Industrial Gas Use | 8.3 | 9.7 | 10.3 | 18% | 24% |
| Gas Production | 29.7 | 39.4 | 44.1 | 33% | 49% |
| Conventional Onshore Gas Production | 9.5 | 5.3 | 4.6 | -44% | -51% |
| Unconventional Onshore Gas Production | 18.6 | 32.0 | 36.9 | 72% | 98% |
| Shale Gas Production | 12.6 | 25.2 | 29.4 | 101% | 134% |
| Offshore Production | 1.6 | 2.1 | 2.6 | 35% | 68% |
| LNG Imports | 0.2 | 0.2 | 0.3 | 11% | 31% |
| LNG Exports | 0.0 | 3.4 | 3.4 | NA | NA |
| Net Exports to Mexico | 0.7 | 1.5 | 1.8 | 124% | 179% |

# Schedule Your Demonstration

**Schedule a 20 minute demonstration with one of our representatives to learn more about the data behind the report.**

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