

The Impacts of U.S. Crude Oil Exports on Domestic Crude Production, GDP, Employment, Trade, and Consumer Costs

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Key Findings on Economic Impacts of Crude Exports

\$5.8b

Estimated reduced
consumer fuel costs/yr
2015–2035

• U.S. weighted average petroleum product prices decline as much as 2.3 cents per gallon when U.S. crude exports are allowed. The greatest potential annual decline is up to 3.8 cents per gallon in 2017. These price decreases for gasoline, heating oil, and diesel could save American consumers up to \$5.8 billion per year, on average, over the 2015–2035 period.

\$70.2b

More investment by 2020

• An expansion of crude exports would result in \$15.2–\$70.2 billion in additional investment in U.S. exploration, development and production of crude oil between 2015 and 2020.

500,000

Barrels per day increase
in domestic crude oil
production by 2020

• With crude exports, U.S. oil production is expected to grow faster and could result in incremental U.S. oil production of between 110,000–500,000 barrels per day in 2020.

300,000

Potential job gains in
2020

• The U.S. economy could gain up to 300,000 jobs in 2020 when crude exports are allowed. Consumer products and services and hydrocarbon production sectors would see the largest gains.

\$38.1b

Projected GDP gain in
2020

• U.S. GDP is estimated to increase by \$38.1 billion in 2020 if expanded crude exports were allowed. GDP increases are led by increases in hydrocarbon production and greater consumer product spending (due to lower retail prices for gasoline and other petroleum products).

\$13.5b

Estimated government
revenues increase in
2020

• U.S. federal, state, and local tax receipts attributable to GDP increases from expanding crude oil exports could reach \$13.5 billion in 2020.

\$22.3b

Estimated reduction of
trade deficit in 2020

• Lifting crude oil export restrictions contributes to expanded U.S. exports. This could narrow the U.S. trade deficit by \$22.3 billion in 2020, assuming all else equal, through increased international trade of U.S. crude oil.

100,000

Barrels per day increase
in refinery throughput
2015–2035

• U.S. refinery throughput is expected to average 15.5 MMBPD without crude export restrictions, which is 100,000 barrels per day higher than with the restrictions. Refinery throughput is slightly higher with crude exports because refinery process bottlenecks (caused by mismatched crudes) are more effectively alleviated by the flexibility to exchange crudes in the world market.

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Glossary

Abbreviations

AEO	EIA Annual Energy Outlook
ANS	Alaska North Slope
Bcf/day (or Bcfd)	Billion cubic feet of natural gas per day
Btu	British thermal unit, used to measure fuels by their energy content.
CAFÉ	Corporate Average Fuel Economy standards to improve the fuel economy of U.S. vehicles first enacted in 1975 that are periodically updated
CAPP	Canadian Association of Petroleum Producers
DPR	Detailed Production Report, ICF's proprietary play-level natural gas, natural gas liquids (NGL), and oil production model
E&P	Exploration and production of oil and gas resources
EF	Eagle Ford crude oil, a light sweet oil produced in Texas
EIA	U.S. Energy Information Administration, a statistical and analytical agency within the U.S. Department of Energy
FOB	Free on Board
GDP	Gross Domestic Product
IEA	International Energy Agency
IMPLAN	Impact Analysis for Planning (IMPLAN) Model, an input-output economic model
KBPD	Thousand Barrels per Day
Mcf	Thousand cubic feet (volume measurement for natural gas)
MMcf	Million cubic feet (of natural gas)
MMBtu	Million British thermal units. Equivalent to approximately one thousand cubic feet of gas
MMBOE	Million Barrels of Oil Equivalent wherein each barrel contains 5.8 million Btus

MMbbl	Million barrels of oil or liquids
MMBPD	Million Barrels per Day
NAICS Codes	North American Industrial Classification System Codes
NGL	Natural Gas Liquids
OGIP	Original Gas in Place
OOIP	Original Oil in Place
Tcf	Trillion cubic feet of natural gas
WCS	Western Canadian Select crude oil, a heavy, sour crude blend produced in western Canada

Terms Used

Economic Terms

Direct Impacts – represent the immediate impacts (e.g., employment or output changes) in Sector A due to greater demand for and output from Sector A. These are the immediate impacts (e.g., employment or value added changes) in a sector due to an increase in output in that sector.

Indirect Impacts – represent the impacts outside of Sector A in those industries that supply or contribute to the production of intermediate goods and services to Sector A. These are impacts due to the industry inter-linkages caused by the iteration of industries purchasing from other industries, brought about by the changes in direct output.

Induced or “Multiplier Effect” Impacts – represent the cumulative impacts of spending of income earned in the direct and indirect sectors and subsequent spending of income in each successive round. Examples include a restaurant worker who takes a vacation to Florida, or a store owner who sends children to college, based on higher income that arises from the initial activity of crude oil exports. These are impacts on all local and national industries due to consumers’ consumption expenditures rising from the new household incomes that are generated by the direct and indirect effects flowing through to the general economy. The term is used in industry-level input-output modeling and is similar to the term Multiplier Effect used in macroeconomics.

Multiplier Effect – describes how an increase in an economic activity produces a cascading effect through the economy by producing “induced” economic activity. The multiplier is applied to the total of direct and indirect impacts to estimate the total impact on the economy. The term is used in macroeconomics and is similar to the term Induced Impacts as used in industry-level input-output modeling.

Oil and Gas Value Chain Terminology

Upstream Oil and Gas Activities – consist of all activities and expenditures relating to oil and gas extraction, including exploration, leasing, permitting, site preparation, drilling, completion, and long-term well operation.

Midstream Oil and Gas Activities – consist of activities and expenditures downstream of the wellhead, including gathering, gas and liquids processing, and pipeline transportation.

Downstream Oil and Gas Activities – activities and expenditures in the areas of refining, distribution, and retailing of oil and natural gas products.

Oil and Gas Resource and Refinery Terminology

Atmospheric Column (also known as Distillation Tower) – the primary process unit in every refinery and the gauge by which refinery capacity is stated. Separates the light, medium, and heavy hydrocarbons present in crude oil into “fractions” or “cuts” by boiling range, which are

then generally subjected to “secondary” processing aimed at increasing yields of higher value products and at improving product quality. In the distillation column, the heaviest “residual” petroleum products remain at the lower levels of the tower, while the lighter products (such as diesel, jet fuel, and naphtha/gasoline), which have shorter carbon chains, vaporize and then condense and are withdrawn at stages up the tower. The lightest products (ethane, propane, butane, and the lightest naphtha) exit at the top of the tower in gaseous form and are “condensed” to recover as much as possible as liquids. When the quality of crude input is altered appreciably from that what column was designed for, bottlenecks can result, which force throughput constraints and reductions. For instance, if a new crude is very light, it can contain so much of the light “overhead” streams that bottlenecks result in that part of the distillation unit, and throughput has to be cut.

Bitumen (also known as oil sands) – an extra heavy crude oil type characterized by high viscosity.

Crack spreads – a term used to estimate the refinery profit margin of a barrel of oil by “cracking” crude oil into petroleum products. There are a number of ways to estimate crack spreads, but a common measure is the 3-2-1 crack spread, which subtracts the cost of **three** barrels of crude oil from the wholesale value of **two** barrels of gasoline plus **one** barrel of distillate oil.

Dilbit – bitumen diluted with diluent to facilitate pipeline transportation of the bitumen.

Diluent – a diluting agent used to dilute the viscosity of bitumen to facilitate bitumen pipeline transportation. Typical diluents include lease condensate, pentanes plus from gas processing plants, butane, synthetic crude, and light crudes.

Conventional natural gas and oil resources – generally defined as those associated with higher permeability fields and reservoirs. Typically, such as reservoir is characterized by a water zone below the oil and gas. These resources are discrete accumulations, typified by a well-defined field outline. Permeability in geological terms is the degree to which a rock formation transmits fluids.

Economically recoverable resources – represent that part of technically recoverable resources that are expected to be economic, given a set of assumptions about current or future production technologies, prices, and market conditions.

Horizontal Drilling – the practice of drilling a section of a well (the lateral) in a horizontal direction (used primarily in a shale or tight oil well). Laterals are typically thousands of feet in length.

Lease Condensate – a light liquid hydrocarbon produced from non-associated natural gas wells. Lease condensate is typically added to the crude oil stream after extraction from natural gas streams.

Natural Gas Liquids – components of natural gas that are in gaseous form in the reservoir, but can be separated from the natural gas at the wellhead or in a gas processing plant in liquid form. NGLs include ethane, propane, butanes, and pentanes.

Original Oil-in-Place – industry term that specifies the amount of oil in a reservoir (including both recoverable and unrecoverable volumes) before any production takes place.

Petroleum Administration for Defense Districts (PADDs) – five PADDs were created during World War II to allocate fuels across the country. The map below shows the PADD-level divisions. Note that PADD 1 (East Coast) is divided up into three sub-regions.

Petroleum Administration for Defense Districts



Source: U.S. Energy Information Administration (EIA). "Today in Energy." EIA, 7 February 2012: Washington, D.C. Available at: <http://www.eia.gov/todayinenergy/detail.cfm?id=4890>

Pre-Flash Tower – a pre-flash tower is a distillation tower that can be added to an existing refinery to separate out the very light hydrocarbons (petroleum gases and light naphthas) from condensate or light crude oil so that the primary atmospheric distillation tower can process the heavy cuts (i.e., fractions or portions)¹ within the process limitations of the atmospheric tower.

Proven reserves – the quantities of oil and gas that are expected to be recoverable from the developed portions (defined by drilled wells) of known reservoirs under existing economic and operating conditions and with existing technology.

¹ For example, refiners refer to liquids that condense between 200 degree Fahrenheit to 250 degrees Fahrenheit as one "cut."

Railbit – similar to dilbit, diluent is added to bitumen to facilitate rail transportation (generally at a lower concentration than that needed for pipeline transport).

Technically recoverable resources – represent the fraction of gas in place that is expected to be recoverable from oil and gas wells without consideration of economics.

Unconventional gas resources – defined as those low permeability deposits that are more continuous across a broad area. The main categories are coalbed methane, tight gas, and shale gas, although other categories exist, including methane hydrates and coal gasification.

Shale gas and liquids – recoverable volumes of gas, condensate, and crude oil from development of shale plays. Tight oil plays include those shale plays that are dominated by oil and associated gas, such as the Bakken in North Dakota (also see: tight oil).

Coalbed methane (CBM) – recoverable volumes of gas from development of coal seams (also known as coal seam gas, or CSG).

Tight gas – recoverable volumes of gas and condensate from development of very low permeability sandstones.

Tight oil – tight oil is light crude oil or condensate contained in petroleum-bearing formations of low permeability, including shales, carbonates, sandstone and combinations of several lithologies. Economic production of tight oil typically involves the application of the same horizontal well and multi-stage hydraulic fracturing technologies that are used to produce shale gas. Although often produced from shales, tight oil should not be confused with oil shale, which is shale rich in kerogen (fossilized organic matter from which hydrocarbons may be generated under high heat and pressures).

Crude Oil Types

Light crude oil – low-viscosity crude oil that is sometimes defined as having an API gravity above 30 degrees (alternative breakpoints are also used). For exhibits in this report, light crude is defined as 35.1 degrees and higher to correspond with breakpoints of certain DOE/EIA historical data series.

Medium crude oil – medium-viscosity crude oil that is sometimes defined as having an API gravity starting somewhere between 22 degrees and 25 degrees and going up to the lower breakpoint of light crude. For exhibits in this report, medium crude is defined as ranging from 25.1 to 35.0 degrees to correspond with breakpoints of certain DOE/EIA historical data series.

Heavy crude oil – high-viscosity crude oil is defined as having an API gravity below the lower breakpoint of medium crude oil. For exhibits in this report, heavy crude is defined as 25.0 degrees and lower. The term “extra heavy oil” is defined as having API gravity below 10.0 degrees.

Sweet crude oil – crude oil that is defined as having a sulfur content of less than 0.5 percent.

Sour crude oil – crude oil defined as having a sulfur content of 0.5 percent or more.

Conversion Factors

Energy Content of Crude Oil

1 barrel = 5.8 MMBtu = 1 BOE

1 MMBOE = 1 million barrels of crude oil equivalent

Energy Content of Natural Gas (1 Mcf is one thousand cubic feet)

1 Mcf = 1.025 MMBtu

1 Mcf = 0.177 barrels of oil equivalent (BOE)

1 BOE = 5.8 MMBtu = 5.65 Mcf of gas

Volume of Natural Gas

1 Tcf = 1,000 Bcf

1 Bcf = 1,000 MMcf

1 MMcf = 1,000 Mcf

Energy Content of Other Liquids

Condensate

1 barrel = 5.3 MMBtu = 0.91 BOE

Natural Gas Plant Liquids

1 barrel = 4.0 MMBtu = 0.69 BOE (actual value varies based on component proportions)

1 Executive Summary

1.1 Background

API asked ICF International (in cooperation with EnSys Energy) to conduct a study of the economic impacts of changing U.S. government policies that prohibit most export of U.S. crude oils. This study provides an analysis of the impacts of a liberalized crude export policy.

The United States government restricted the export of most domestically produced crude oil starting in 1973, a time when U.S. oil production was in decline.² In recent years, the oil and gas industry reversed the downward crude oil production trajectory through a technological revolution. Horizontal well drilling and multi-stage hydraulic fracturing are now utilized to access oil and gas resources that were previously either technically impossible or uneconomic to produce. Between 2009 and 2013, U.S. crude oil production³ has increased by 2.1 million barrels per day (MMBPD) (39 percent)⁴ and is projected to increase another 3.2–3.3 MMBPD through 2020, according to ICF/EnSys estimates. Forecasts of substantial near-term production increases have also been made by the U.S. Energy Information Administration (1.8 MMBPD increase from 2013 to 2020) and other forecasts cited later in this report.⁵ This production revolution has fundamentally altered the domestic flow of crude oil, with states such as North Dakota and

Key Points

- *The U.S. may become the world's leading crude oil producer over the next decade, largely through production of lighter crude oil.*
- *Current restrictions on the export of crude oil, developed at a time when U.S. oil production was in decline, limit the U.S.' ability to efficiently use crude oil supplies.*
- *U.S. refineries are mostly designed to accommodate heavy (rather than light) crudes.*
- *Refineries are expected to continue to make adjustments to accommodate lighter crudes, but may have a difficult time keeping up with growing U.S. light crude and condensate production.*
- *The U.S. crude oil supply glut is apparent in the discount seen in recent months in U.S. light crude oil prices, relative to international benchmarks.*
- *Because the U.S. allows import and export of petroleum products, such as gasoline and diesel, U.S. petroleum product prices follow international market dynamics, regardless of the differentials between U.S. and international crude oils.*
- *Expanding flexibility to export crude oil would allow refiners to operate more efficiently, running heavy crude oil, while export of light crude oil is expected to modestly reduce international oil prices, and, by extension, U.S. gasoline and diesel prices.*
- *Expanding crude oil exports is expected to increase U.S. crude oil production, leading to net gains in employment, GDP, and government revenues.*

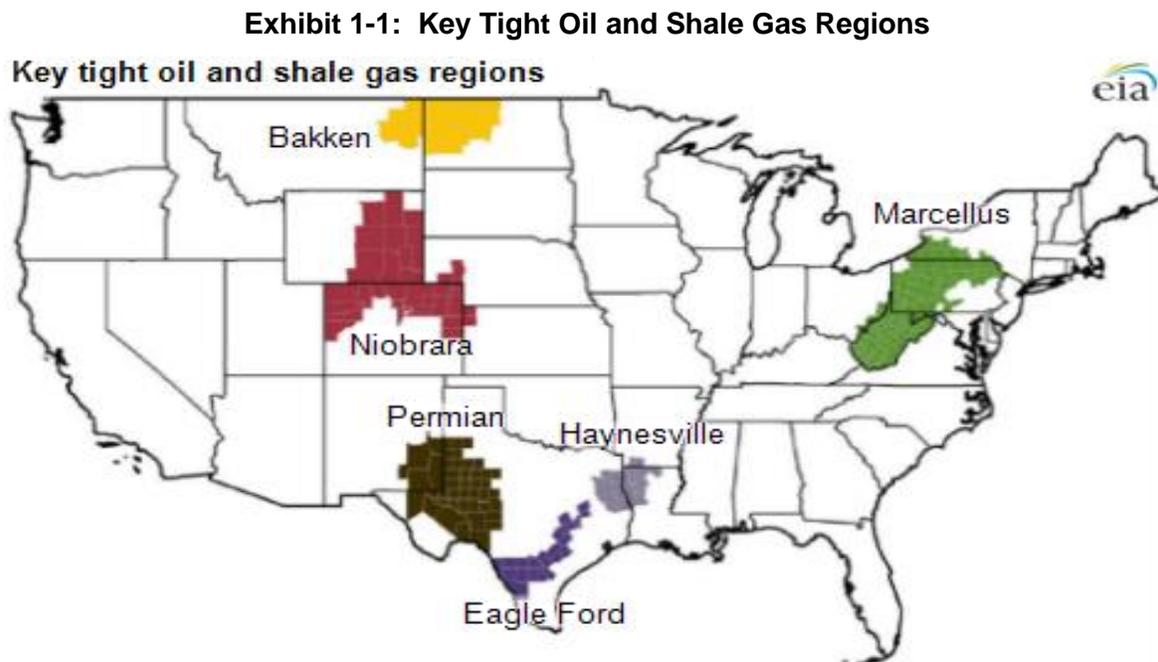
² The United States currently allows export of domestic crude oil in a few cases, such as the following: 1) from oil produced in Alaska's North Slope and Cook Inlet, 2) up to 25,000 BPD in production from California's heavy oil fields, and 3) crude exports to Canada if the crude supplies remain in Canada or are re-exported to the United States. Other options are also permitted (e.g., exports of oil in exchange for strategic petroleum reserve volume) under defined conditions.

³ Including lease condensate

⁴ U.S. Energy Information Administration (EIA). "Crude Oil Production." EIA, September 2013: Washington, D.C. Available at: http://www.eia.gov/dnav/pet/pet_crd_crdpn_adc_mbbbl_a.htm

⁵ U.S. Energy Information Administration (EIA). "Annual Energy Outlook 2014 Early Release." EIA, 16 December 2013. Available at: <http://www.eia.gov/forecasts/aeo/er/index.cfm>

Texas now producing substantial volumes of tight oil.⁶ The new oil supplies, made up primarily of light sweet crude oil and lease condensate, are concentrated in the Bakken (MT, ND), Niobrara (CO, WY), Permian (NM, TX), and Eagle Ford (TX) shale plays, as shown in the exhibit below.^{7,8}



Source: U.S. Energy Information Administration (EIA). "Today in Energy." EIA, 22 October 2013: Washington, D.C. Available at: <http://www.eia.gov/todayinenergy/detail.cfm?id=13471>

Construction of new pipeline infrastructure to connect new tight oil plays to traditional demand markets (i.e., refineries) has lagged behind production growth. This has created significant transportation bottlenecks as new supply from sources such as North Dakota could not be shipped to demand areas elsewhere around the country. Over the past several decades, U.S. oil pipeline infrastructure was geared to transport domestic and foreign oil from locations such as the Gulf Coast north to demand markets. However, growing North Dakota tight oil production led to a southward shift in movements of crude to refineries in the midcontinent region. Until very recently, these additional domestic supplies and Canadian crude imports became bottlenecked at Cushing, a large supply hub in Oklahoma, as there was not sufficient pipeline infrastructure to move the crude south from Cushing to the major Gulf Coast refining center.

As shown in the exhibit below, the rapid tight oil production growth coupled with the lack of infrastructure connecting new supply sources to demand markets became apparent in the late

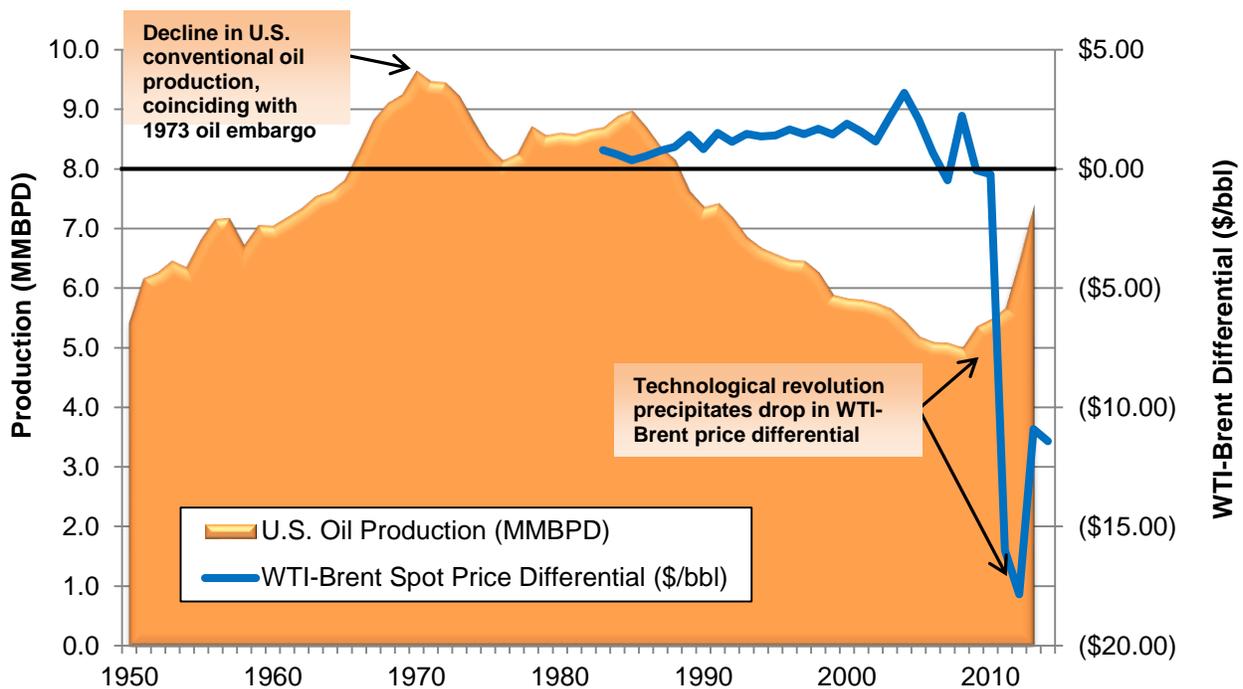
⁶ Tight oil is light crude oil or condensate contained in petroleum-bearing formations of low permeability, including shales, carbonates, sandstone and combinations of several lithologies. Economic production of tight oil typically involves the application of the same horizontal well and multi-stage hydraulic fracturing technologies that are used to produce shale gas.

⁷ To correspond with breakpoints of certain DOE/EIA historical data series, this study defines light crude as having API gravity of 35.1 degrees and higher, medium crude ranging from 25.1 to 35.0 degrees, and heavy crude as 25.0 degrees and lower.

⁸ Sweet crude oil is defined as having a sulfur content of less than 0.5 percent, while sour crude oil is defined as having a sulfur content of 0.5 percent or more.

2000s as evidenced by the drop in U.S. West Texas Intermediate (WTI) Cushing benchmark crude oil price relative to the international comparable benchmark crude. The exhibit shows the historical price spread between WTI—the U.S. oil price benchmark for light sweet crude—and the North Sea Brent price—considered the international oil price benchmark. WTI prices historically were at a slight premium relative to Brent. The WTI-Brent price spread averaged positive \$1.30 per barrel between 1983 (the earliest year for which data is available) and 2008. The differential became more volatile starting with the financial crisis and commodity price collapse in 2008, before plunging to a discount of \$17.00/bbl in 2011 and 2012 due to the Cushing bottleneck as tight oil production continued to grow.

Exhibit 1-2: Historical U.S. Oil Production and WTI-Brent Spot Price Spreads



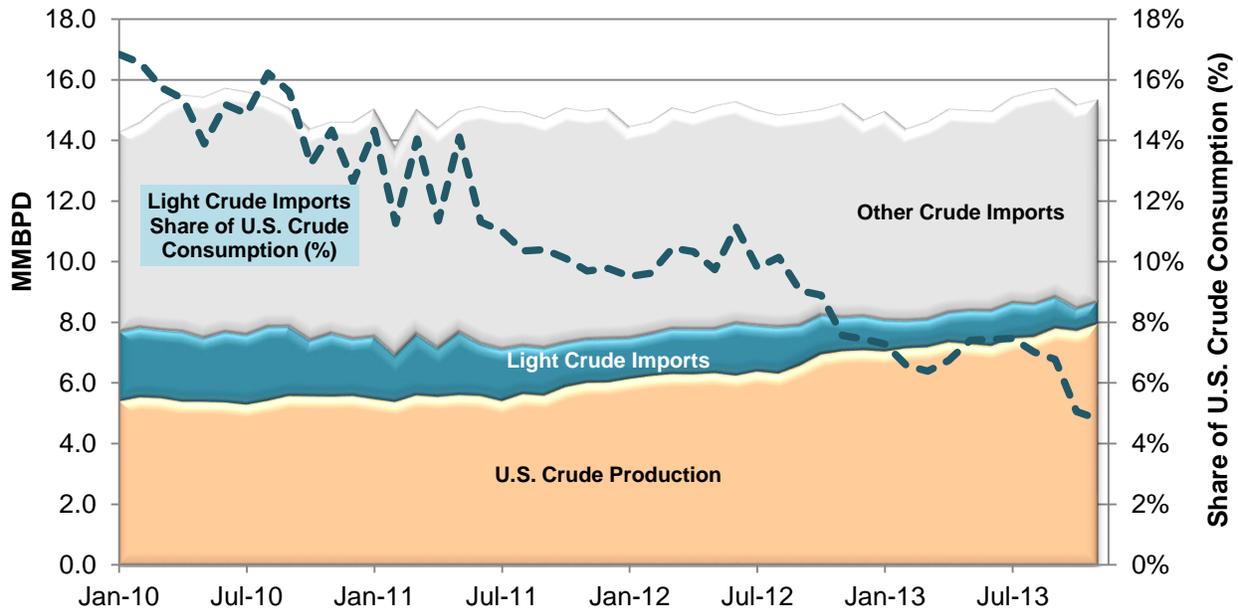
Sources: EIA – oil production; Bloomberg – WTI and Brent spot FOB prices.

Additional pipeline capacity has been added and is under construction to alleviate this bottleneck. Capacity from Cushing to the Gulf Coast, as well as from the Permian region into the Houston refining center has increased. The ongoing development of this infrastructure has opened the pathways for light crude to reach the Gulf Coast, and provided producers higher prices while allowing Gulf Coast refiners access to the discounted light crude. At the same time, East and West Coast refiners do not have access to new tight oil by pipeline, and have been developing rail capabilities to access domestic crudes, such as from the Bakken in North Dakota, allowing them to reduce imports of light sweet, globally-priced crude oils.

Tight oil production, which is characterized as light sweet crude oil and lease condensate, is expected to continue to fuel the bulk of future U.S. oil production growth. As shown below, this production growth is replacing light oil imports, mostly African crude oil, at an increasing clip. Between January 2010 and January 2014, the light oil imports dropped by nearly two-thirds to

790,000 barrels per day (BPD) for the U.S. In the Gulf Coast (PADD 3), light oil imports are currently only about 245,000 BPD, and a portion of these are for lubricant oil manufacturing (requiring a specific crude oil quality).⁹

Exhibit 1-3: Historical U.S. Oil Production and Light Crude Imports



Sources: U.S. Energy Information Administration (EIA). "Crude Oil Production." EIA, 27 February 2014: Washington, D.C. Available at: http://www.eia.gov/dnav/pet/pet_crd_crdpn_adc_mbbbl_m.htm. U.S. Energy Information Administration (EIA). "Refinery Net Input." EIA, 27 February 2014, Washington, D.C. Available at: http://www.eia.gov/dnav/pet/pet_pnp_inpt2_a_epc0_Y1Y_mbbbl_m.htm

Note: The light crude imports include crude oil imports with API gravity of 35 degrees and above.

There is a fundamental mismatch between U.S. refinery capabilities, configured for heavier oils, and the country's newfound supply, comprised of lighter oils. Although the initial (physical) bottleneck at the Cushing, OK hub that caused the discount of U.S. oil prices has been alleviated for the most part, the prices for U.S. light crudes and condensates have experienced a persistent differential with comparable but higher priced world crude such as Brent since August 2013. Analysts have attributed this differential to U.S. refiners encountering constraints that prevent them from processing all of the growing U.S. light crude and condensate volumes. Refiners are planning investments to increase the ability to process lighter oils, but it is uncertain whether these investments can keep up with growing U.S. light crude and condensate production. There is a high probability that this differential between U.S. and comparable international crudes will persist over the medium term. In addition, given the global nature of petroleum product prices (such as gasoline and diesel), lower crude prices in one region do not necessarily translate to lower product prices.

⁹ Based on the 2013 average for PADD 3 (as PADD for crude processing) crude oil imports with API gravity of 35 degrees and above. U.S. Energy Information Administration (EIA). "Company-level Imports" EIA, 27 February 2014: Washington, D.C. Available at: <http://www.eia.gov/petroleum/imports/companylevel/>

With U.S. light oil imports at less than 800,000 barrels per day (BPD) and additional growth of production of 3.4 million barrels per day by 2020 anticipated, the “Cushing bottleneck” will soon become a “national” bottleneck. As producers extend pipeline and rail infrastructure, U.S. refiners will gain access to an increasing supply of tight oil crudes and condensates. Refiners will then have to reconfigure to run the new lighter crudes. The Cushing bottleneck foretells a similar outlook for producers as refining capacity becomes the limiting factor on processing the new domestic crude.

This outlook is expected to have ramifications for the U.S. economy as tight oil production grows and options to domestically process the light crudes and condensate become constrained. Historically, many U.S. refineries were adapted to process heavier crude oil. However, the new and growing U.S. production is primarily light crude oil and lease condensate. After backing out all light oil imports, the U.S. is still expected to have a net surplus of light oil production. Due to a combination of flat or declining domestic petroleum product demand, refinery capacity limits to process light oil feedstocks, and continued refinery demand for heavy oils (due to both refinery configuration and long-term import contractual obligations), the U.S. surplus of light oil is expected to increase.

Questions This Study Addressed:

- **How “binding” will the crude export constraint be in the coming years and how much of a price depression will result between U.S. crude prices and prices for comparable global crudes?**
- **How would U.S. production and trade in crudes be affected by lifting the export constraints?**
- **How would refinery throughputs be affected if crude exports were allowed?**
- **What would be the impacts on prices of U.S. and global crudes and U.S. petroleum product prices if crude exports were allowed?**
- **What would be the economic impacts of allowing crude exports in terms of GDP, jobs, and balance of trade?**

1.2 Energy and Pricing Impacts of Crude Oil Exports

This study focused on assessing the impact of lifting the crude oil export restrictions on the U.S. crude oil supply-demand balance and the international supply-demand balance, both in terms of volumetric and pricing changes. The study compared supply-demand trends in a world with continued crude oil export restrictions to a scenario in which the restrictions are lifted. A key focus throughout this report is on differential impacts between the export-restricted and non-restricted cases. Because of the uncertainty in several factors that could affect near- and

medium-term crude prices, ICF created two market scenarios within which export policy could be examined:

- **A Low WTI-Brent Price Differential Market Scenario (Low-Differential Scenario)** – Assumed relatively rapid accommodation of light crudes and condensate, notably that the following would occur by 2015, leading to a narrowing in WTI-Brent differentials:
 - Continued swift buildout and availability of rail capacity to take Bakken and Niobrara crudes out to the U.S. East and West, as well as Gulf coasts.
 - Similar buildup in capacity to ship Eagle Ford crude and condensate via marine terminals at Corpus Christi, enabling expanded movements by sea to refineries in eastern Canada and the U.S. Northeast.
 - No constraints on fully backing out all light sweet crude imports into the Gulf, East and West coasts.
 - Similarly, a degree of flexibility in backing out medium sour crudes imported into the U.S., notably into the Gulf Coast.
 - Announced refinery projects to enable running light crudes all come on-stream by 2015 (but no further adaptations made by then).
- **A High WTI-Brent Price Differential Market Scenario (High-Differential Scenario)** – Assumed that inertial factors and delays would slow the adaptations to changing crude slate that were assumed in the Low-Differential Scenario, with the result that WTI-Brent differentials would remain wide, at least for several years. While some refiners have invested to process more light crude, others may be reluctant to risk significant capital on higher-cost refinery investments to accommodate lighter crude slates due in part to the uncertainty around crude export policies and the outlook for tight oil production growth. In addition, permitting requirements can adversely affect project timing and delay implementation. These could prevent announced refinery projects from coming on-stream until after 2015. Equally, there could be delays in the implementation of the extensive list of announced projects for crude-by-rail capacity. Crude supply contracts in place and equity ownership stakes in refineries could slow the displacement of imported crudes by domestic grades. These factors would contribute to the wider WTI-Brent price differentials assumed in the High-Differential Scenario, thus prolonging U.S. crude price discounting relative to global prices.

Both the Low-Differential and High-Differential scenarios include two policy cases:

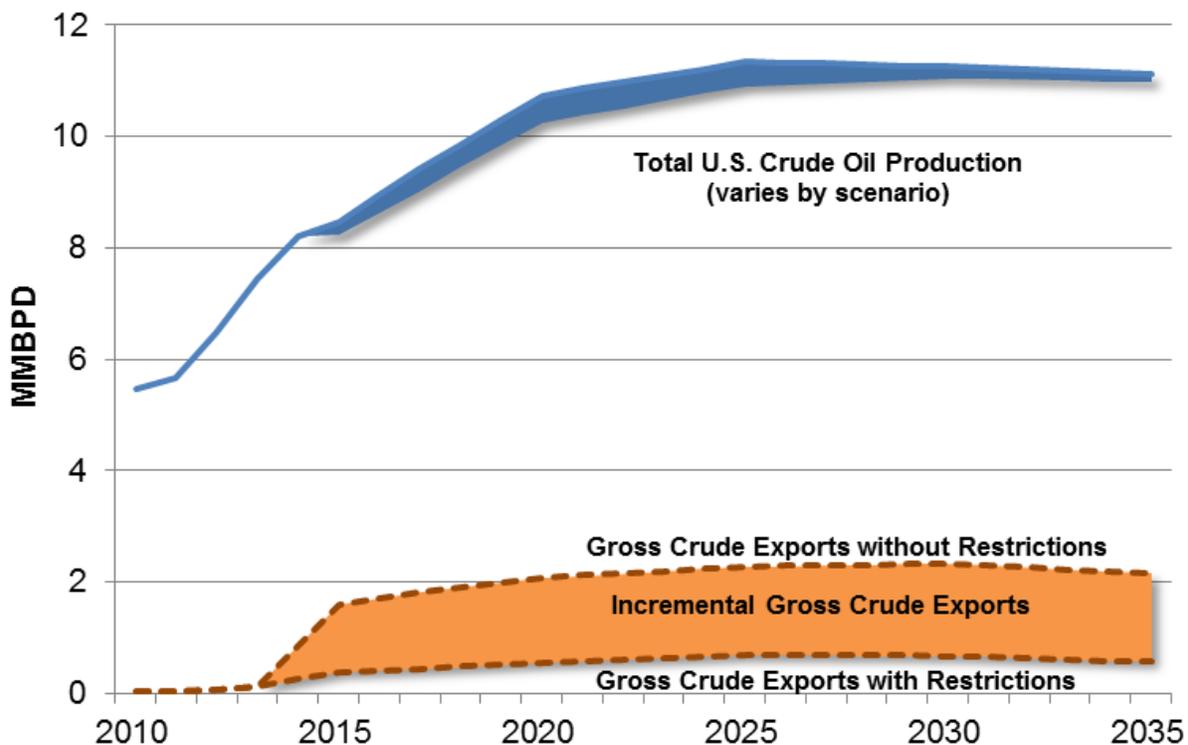
- **Base Case (No Exports Policy Case)** – Results based on the assumption that existing restrictions on crude exports remains in place.¹⁰

¹⁰ This case assumed a continuation of current crude export policy in which the United States permits export of crude oil in a few cases such as the following: 1) from oil produced in Alaska's North Slope and Cook Inlet, 2) up to 25,000 BPD in production from California's heavy oil fields, and 3) crude exports to Canada if the crude supplies remain in Canada or are re-exported to the United States. Other options are also permitted (e.g., exports of oil in exchange for strategic petroleum reserve volume) under defined conditions.

- With Exports Policy Case – Results based on the assumption that all restrictions on crude exports are lifted.

This study found that the U.S. petroleum industry would, based on global markets and transportation costs, have a strong incentive to export lower priced domestic crude to global markets where prices for similar quality crudes are higher. This “arbitrage” will drive higher exports, as a free market export policy will cause producers to seek higher prices for their domestic crude oil. The study found that based on global markets, a free market export policy would drive an average of 2.1 MMBPD crude oil exports between 2015 and 2035. Under the current export policy, crude oil exports would average about 580,000 BPD and result in lower crude oil production and fewer long-term economic benefits to U.S. consumers.

Exhibit 1-4: Gross Crude Exports and Share of U.S. Crude Production

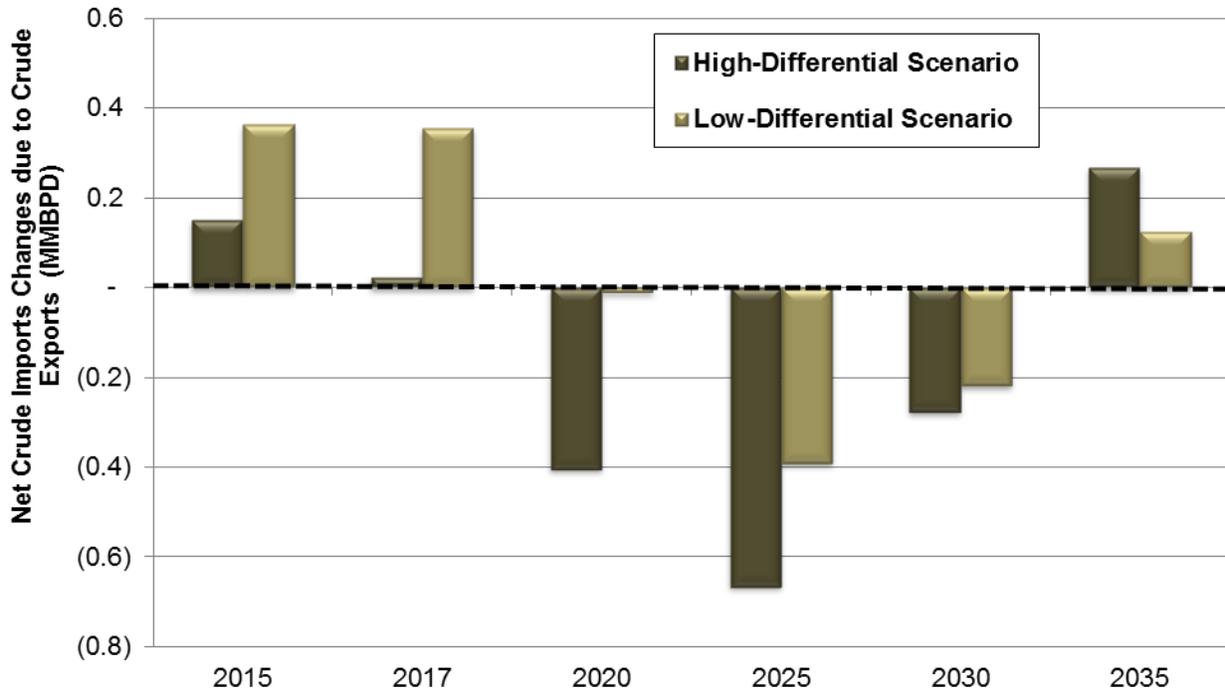


Sources: EIA – historical; ICF International and EnSys Energy – projections

The U.S. is projected to remain a net crude importer through 2035 in the cases examined in this study. Average net imports of crude are approximately equal in all cases with and without exports (within 30,000 BPD on average between 2015 and 2035). As exports of light crude oil are allowed, imports of heavier crudes increase to better align with existing refinery configurations leaving net imports little changed as shown in Exhibit 1-5. Heavier crudes are expected to comprise an increasing share of imports as U.S. tight oil and condensate production back out light imports. For historical reference, net crude imports averaged 9.0 MMBPD in 2000 and dropped to 7.6 MMBPD by 2013. Net crude imports are projected to be between 4.5 and

4.8 MMBPD by 2035 with or without restrictions. The exhibit below shows net crude import changes due to crude exports.

Exhibit 1-5: Net Crude Imports do not Change Considerably due to Crude Exports



Sources: EnSys WORLD Model and ICF analysis

Note: In all cases, crude exports to Canada are allowed.

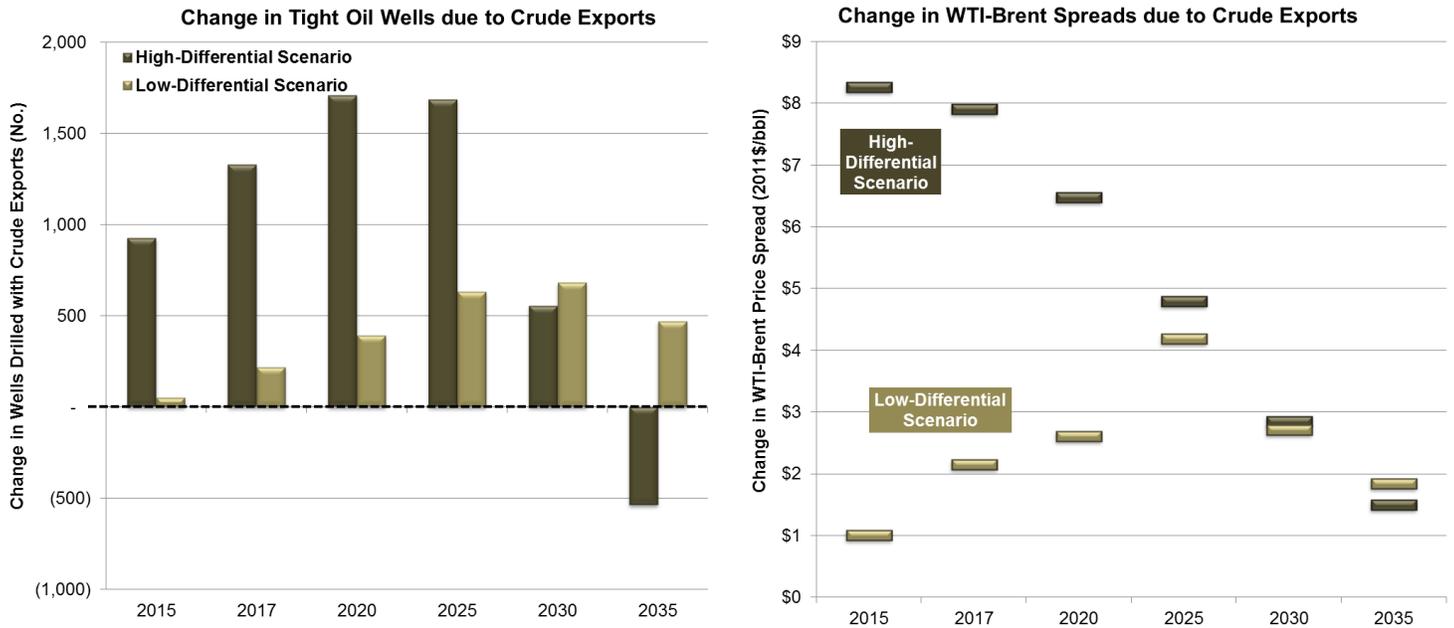
When exports are restricted, U.S. crudes are bottlenecked, which results in their pricing being discounted. With crude exports, U.S. and international crudes are in direct competition, and will move WTI prices closer to comparable global oil prices. In addition, the Brent price drops when U.S. crude exports are allowed, as U.S. incremental crude production increases overall global supply. WTI prices are projected to average \$2.25–\$4.00/bbl higher over the 2015–2035 period relative to the no export case, depending on the scenario, while global oil prices are approximately \$0.35–\$0.75/bbl lower over the same time period.¹¹ WTI-Brent price differentials narrow with crude exports from \$7.50/bbl in the Low-Differential Scenario, or \$9.60/bbl in the

¹¹ All projected prices for 2015-2035 in this report are in 2011 dollars, unless otherwise specified.

High-Differential Scenario when exports are constrained, to a differential of \$4.85/bbl when export restrictions are relieved in both the Low- and High-Differential Scenario.

The High-Differential Scenario results in much larger drilling activity and production in the early years in comparison to the Low-Differential Scenario. This is because the WTI price adjustment is much larger in the early years in the High-Differential Scenario vs the Low-Differential Scenario when exports are allowed. In the longer term the WTI price adjustments in both study cases converge, and so, the impacts on drilling levels and production are similar.

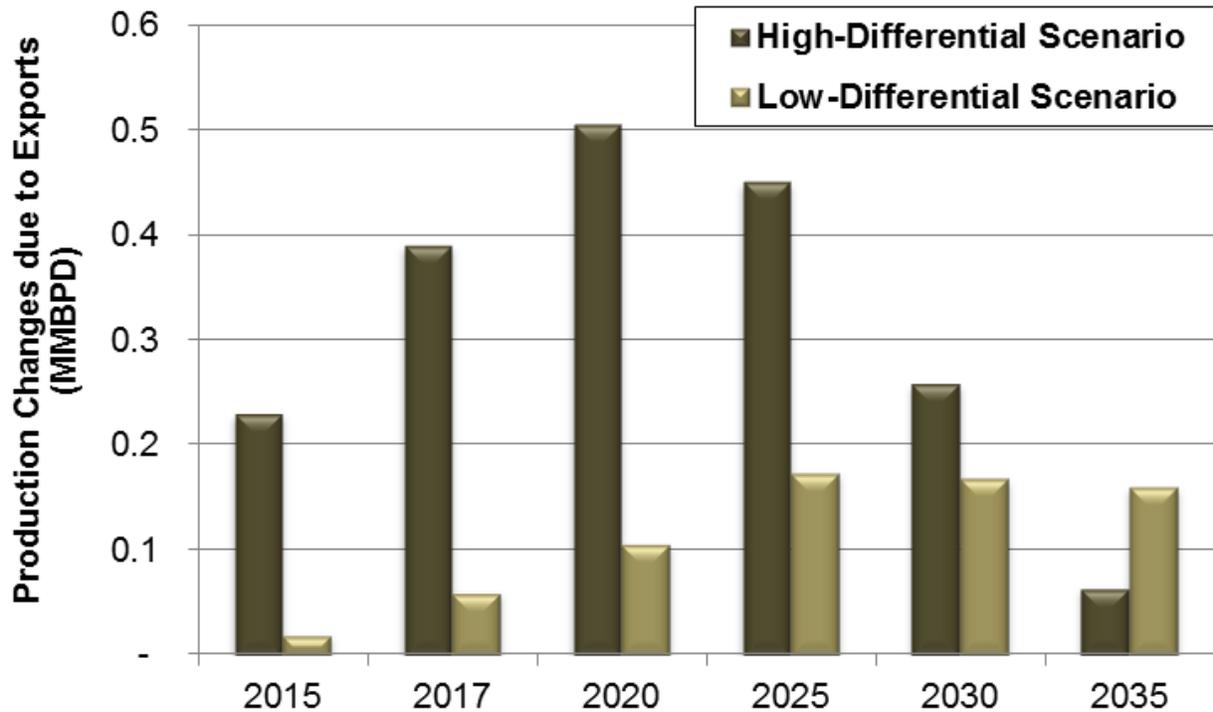
Exhibit 1-6: Allowing Crude Exports Increases Tight Oil Wells Drilled



Sources: EnSys WORLD Model and ICF analysis – projections; EIA pricing forecasts adjusted by EnSys WORLD Model and ICF analysis for case scenarios

Historically, U.S. crude production grew from an annual average of 5.8 MMBPD in 2000 to 7.4 MMBPD in 2013. This study projected that U.S. crude production will average 10.7 MMBPD between 2015 and 2035 with crude exports. Lifting crude export restrictions is projected to increase U.S. crude oil production by approximately 110,000 to 500,000 BPD by 2020, depending on the scenario. This additional crude production would come about through \$15.2–\$70.2 billion in additional investment between 2015 and 2020.

Exhibit 1-7: U.S. Crude Production Will Be Higher if Exports Are Allowed

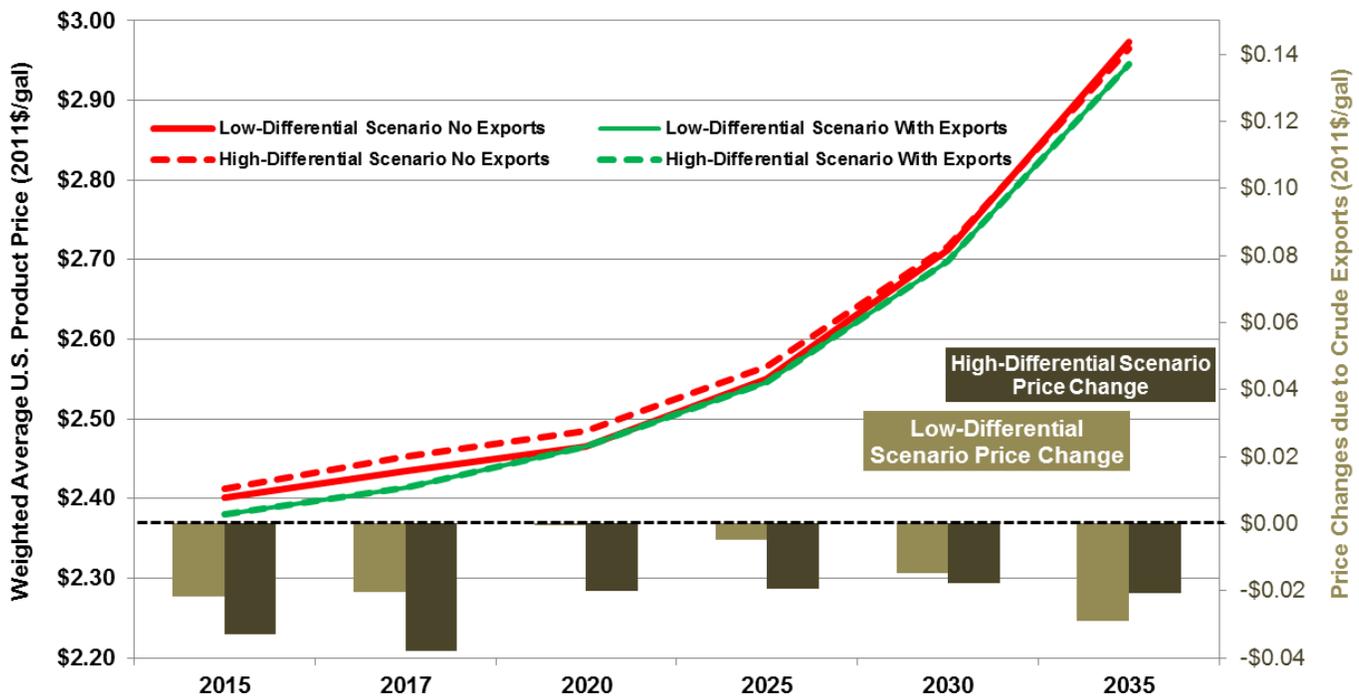


Sources: EnSys WORLD Model and ICF analysis

1.3 Refined Product Pricing Impacts of Crude Oil Exports and Consumer Fuel Savings

This study found that average U.S. wholesale product prices, weighted by product type volumes, decline an average of 1.4–2.3 cents per gallon between 2015 and 2035 due to crude oil exports, with wholesale prices averaging about \$2.60 per gallon over 2015 to 2035 with crude exports. This price decline could save American consumers up to \$5.8 billion per year, on average, over the 2015–2035 period. Price declines due to crude exports are largest in 2017 in the High-Differential Scenario, with U.S. wholesale product prices dropping 3.8 cents, translating to consumer fuel savings of \$9.7 billion. This price decline is similar in magnitude to another study of crude exports and impacts on U.S. pricing.¹²

Exhibit 1-8: Weighted Average U.S. Wholesale Product Price Impacts



Sources: EnSys WORLD Model and ICF analysis

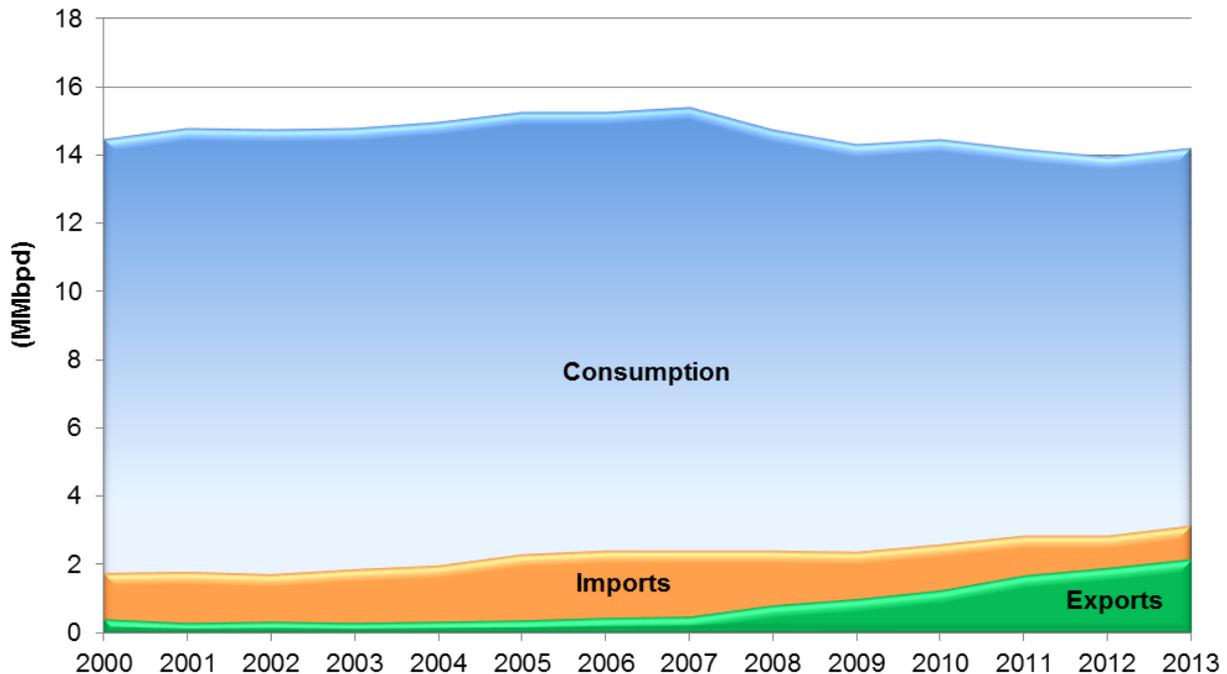
The United States has long participated in the international trade in refined petroleum products. Between 2000 and 2013, U.S. trade in major refined petroleum products (gasoline, distillates such as diesel and heating oil, jet fuel, kerosene, and propane) increased from 1.8 MMBPD in 2000 to 3.1 MMBPD in 2013, as shown in the exhibit below. Over the period, product imports have trended down slightly, while exports have increased from 0.4 MMBPD to 2.2 MMBPD. Product imports and exports now comprise 22 percent of consumption, up from 12 percent in 2000. This trend illustrates that discretionary U.S. product supply has either been imported into

¹² A recent Resources for the Future (RFF) study found that lifting the U.S. crude oil export restrictions would result in a decrease in the wholesale price of gasoline by 1.7 to 4.5 cents per gallon.

Brown, Stephen P.A.; Charles Mason; Alan Krupnick; and Jan Mares. "Crude Behavior: How Lifting the Export Ban Reduces Gasoline Prices in the United States." Resources for the Future (RFF), February 2014: Washington, D.C. Available at: <http://www.rff.org/RFF/Documents/RFF-IB-14-03-REV.pdf>

or exported from the global markets. The exhibit below shows U.S. trade in petroleum products has trended upward historically (shown by imports and exports), while exports' share of this trade has risen considerably since 2009.

Exhibit 1-9: Consumption and Trade of Selected U.S. Petroleum Products*



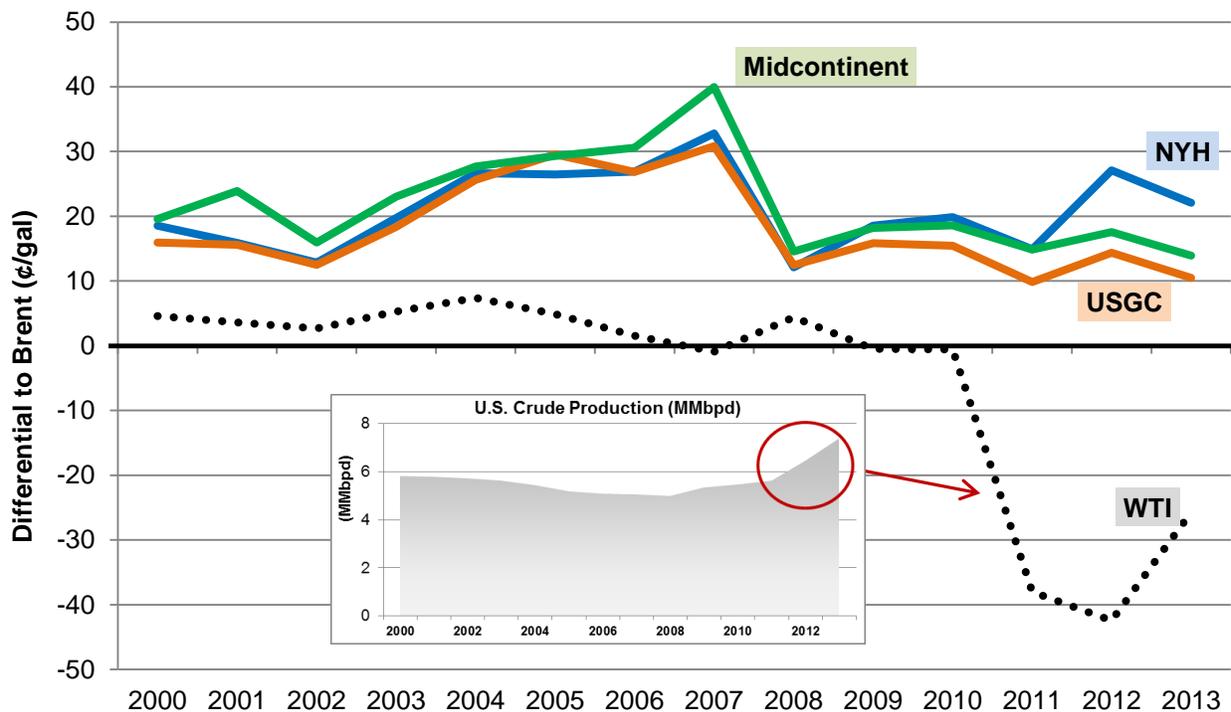
Source: U.S. Energy Information Administration (EIA). "Prime Supplier Sales Volumes." EIA, 25 February 2014: Washington, D.C. Available at: http://www.eia.gov/dnav/pet/pet_cons_prim_dc_nus_m.htm U.S. Energy Information Administration (EIA). "Petroleum and Other Liquids: Exports." EIA, 25 February 2014: Washington, D.C. Available at: http://www.eia.gov/dnav/pet/pet_move_exp_dc_nus-z00_mbbld_m.htm U.S. Energy Information Administration (EIA). "Petroleum and Other Liquids: Imports." EIA, 14 March 2014: Washington, D.C. Available at: http://www.eia.gov/dnav/pet/pet_move_imp_dc_nus-z00_mbbld_a.htm

* Includes gasoline and gasoline blendstocks, distillates, jet fuel, kerosene, and propane

The cost of delivered crude oil and the value of the primary products from refining influence the operating strategy of the U.S. refining sector. U.S. refiners are competing with global suppliers (traders and foreign refiners) who have the ability to bring product into the U.S. market or purchase product in the U.S. market to export. U.S. refiners supply both domestic and international demand, and also receive product from international sources. Because of these strong market connections, U.S. product prices are set by world prices rather than U.S. crude prices. In recent years U.S. refiners have benefitted from relatively lower domestic crude and natural gas prices to sustain or increase crude runs (despite lower domestic demand) and export gasoline, diesel, and propane to global markets at prices that support processing the crude oil. In addition, as pointed out above, the refinery margins through 2035 are projected to trend somewhat higher from levels seen over the past few years, either with a continuation of current crude export policy or with an expansion of crude exports.

As shown in the exhibit below, the discount in WTI prices after 2010, relative to international benchmarks such as Brent crude, did not translate to lower U.S. refined product prices. This was the case even in the midcontinent, where WTI is physically bought and sold. The midcontinent region is short of refinery capacity to meet its own demands and imports product from the Gulf Coast at Gulf Coast product price levels to balance supply and demand.

Exhibit 1-10: U.S. Petroleum Product Prices Linked to Global Crude Prices



Source: Prices – Bloomberg. Crude production – U.S. Energy Information Administration (EIA). “U.S. Field Production of Crude Oil.” EIA, February 2014; Washington, D.C. Available at: <http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPUS2&f=M>

Note: Group 3 refers to Midcontinent 87 octane gasoline prices (Bloomberg ticker: G3OR87PC Index), NYH refers to New York Harbor (NYH) 87 octane gasoline prices (Bloomberg ticker: MOINY87P Index), USGC refers to U.S. Gulf Coast (USGC) 87 octane gasoline prices (Bloomberg ticker: MOINY87P Index). WTI refers to West Texas Intermediate (WTI) crude oil spot price (Bloomberg ticker: U.S.CRWTIC Index). Brent refers to Brent crude oil spot price (Bloomberg ticker: EUCRBRDT Index). Prices on graph show the differential to Brent prices.

The U.S. refining sector comprised roughly 22 percent of global refining throughput processed between 2000 and 2010, with U.S. refined products exports making up an average of six percent of global exports.¹³ A differential in refined product cost between U.S. and international markets creates opportunities for arbitrage for both traders and refiners. Much of the gasoline supply for the U.S. Northeast is from imports of gasoline and gasoline blendstocks

The fact that the U.S. refinery sector participates in international product trade means that U.S. refined product prices follow international markets.

¹³ U.S. Energy Information Administration (EIA). “International Energy Statistics.” EIA, 2014; Washington, D.C. Available at: <http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=5&pid=alltypes&aid=1&cid=ww.US.&syid=2008&eyid=2000&unit=TBPD>

from Europe by traders and blenders, while at the same time U.S. refiners are exporting gasoline and diesel from the Gulf Coast to Latin America and other countries. These facts indicate that the U.S. product supply is being optimized in a global market, based on prices in global markets. The larger discounts in domestic crude oil prices due to crude export restrictions improve U.S. refinery margins but do not reduce gasoline or diesel prices, as refiners will have the ability to export these products at global market prices.

This study projects only relatively small differences in U.S. refinery throughputs between cases with and without export restrictions. The model runs show that when export restrictions are lifted, the U.S. exchanges exports of light crudes and condensates for additional imports of medium and heavy crudes, while leaving refinery throughput at similar levels. U.S. refinery throughput was 15.2 MMBPD in 2013. Refinery throughput is expected to increase to a 2015–2035 average of 15.5 MMBPD if the crude export restrictions are lifted, which is 100,000 BPD or 0.6 percent higher than would exist if the restrictions were kept in place. Refinery throughput is slightly higher in the Exports Case because refinery process bottlenecks caused by mismatched crudes are more effectively alleviated by the flexibility to exchange crudes.

U.S. refinery gross margins¹⁴, the difference between the cost of the refinery feedstock (primarily crude) and outputs (such as gasoline and other refined petroleum products) are projected to decline with increased crude oil exports. This is due to a combination of higher domestic U.S. crude prices and slightly lower refined product prices. Per-barrel refinery margins average \$12.75/bbl over the period to 2035 when crude exports are allowed, roughly \$1.50/bbl lower than when exports are restricted in the Low-Differential Scenario, or \$2.85/bbl lower in the High-Differential Scenario with export restrictions. Average gross refinery margins reached as high as \$14.23/bbl in 2005, they dropped to an annual average of \$6.54/bbl in 2013. Refinery margins are projected to trend higher with or without export restrictions due to global trends toward lighter and higher quality products, such as diesel fuel and jet fuel, at the expense of residual oil products.

Refined petroleum product net exports are roughly the same with and without the crude export restrictions; this is because U.S. refining throughputs and product demand varied little between the Exports and No Exports cases.

1.4 Employment and Economic Impacts of Crude Oil Exports

The study found that lifting the restrictions on crude exports results in economic gains stemming, in large measure, from increasing U.S. crude oil production. This change in production stimulates indirect activities such as the manufacture of drilling equipment, increasing demand for steel pipe, and cement, as well as other materials, equipment, and services. These direct and indirect effects have an upward impact on the economy, which is quantified below. In addition, there are induced or “multiplier effect” impacts, which represent

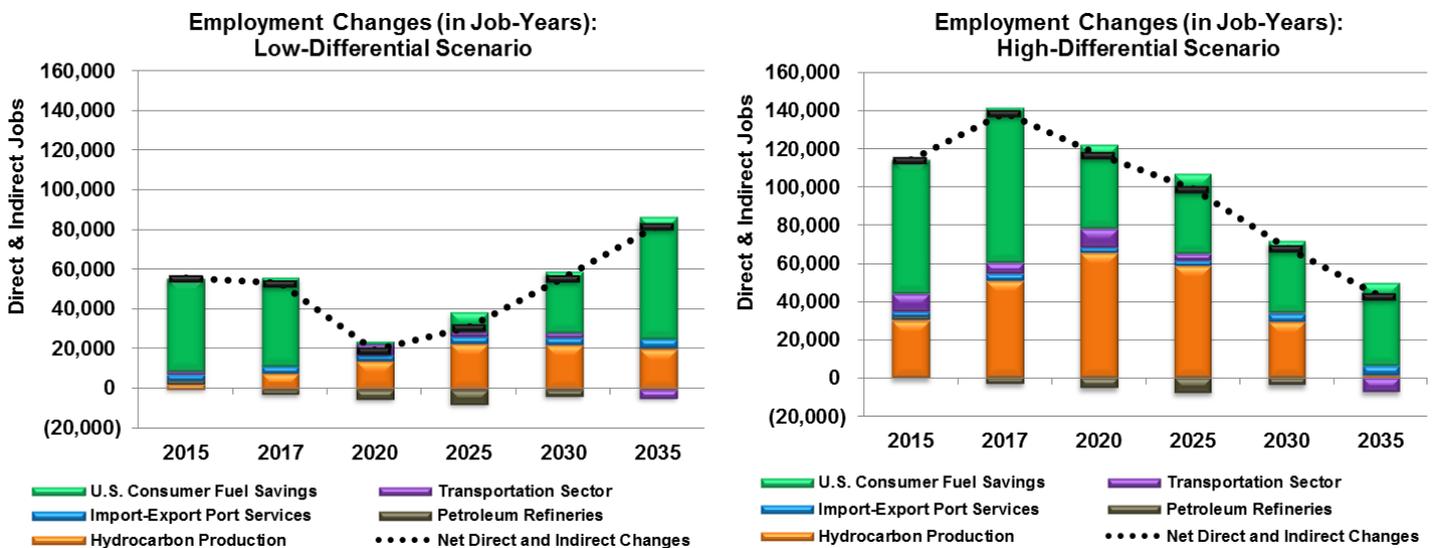
¹⁴ As used in this study, gross refinery margin equals total value of products from refinery (yield times price for each product) minus crude cost (fraction of each crude in feedstock times its price). PADD-level average gross margins were first computed and then weight averaged by PADD-level refinery throughputs to arrive at a national average gross margin.

the additional impacts of income earned by employees in the direct and indirect sectors. Given the uncertainty surrounding multiplier effects, this study applied ranges, which are described in more detail in Section 3.

The ICF methodology calculated direct and indirect employment impacts (relative to the base case trend of no exports) by multiplying the change in production in a given sector (measured in dollars or physical units) times the labor needed per unit of production. Crude exports result in net direct and indirect employment gains in the Low-Differential and High-Differential scenarios, which average between 48,000 and 91,000 jobs annually over the forecast period, respectively. Direct and indirect job gains are concentrated in consumer-related and hydrocarbon production activities. The exhibit below shows the direct and indirect employment changes associated with lifting the crude export restrictions. Employment changes in the Low-Differential Scenario are lower than in the High-Differential Scenario because the High-Differential Scenario has a wider WTI-Brent price spread that results in larger economic impacts when the export constraints are lifted and WTI prices rise to come closer to world crude price levels.

The impacts of lifting the crude export restrictions on the U.S. economy are larger in the High-Differential Scenario than the Low-Differential Scenario. Refinery and transportation infrastructure investments that are needed to better accommodate lighter domestic crudes are slower in the High-Differential Scenario when crude export restrictions remain in place, thus prolonging the depression in U.S. crude prices relative to international prices.

Exhibit 1-11: Direct and Indirect Employment Increases due to Crude Exports



Source: ICF analysis

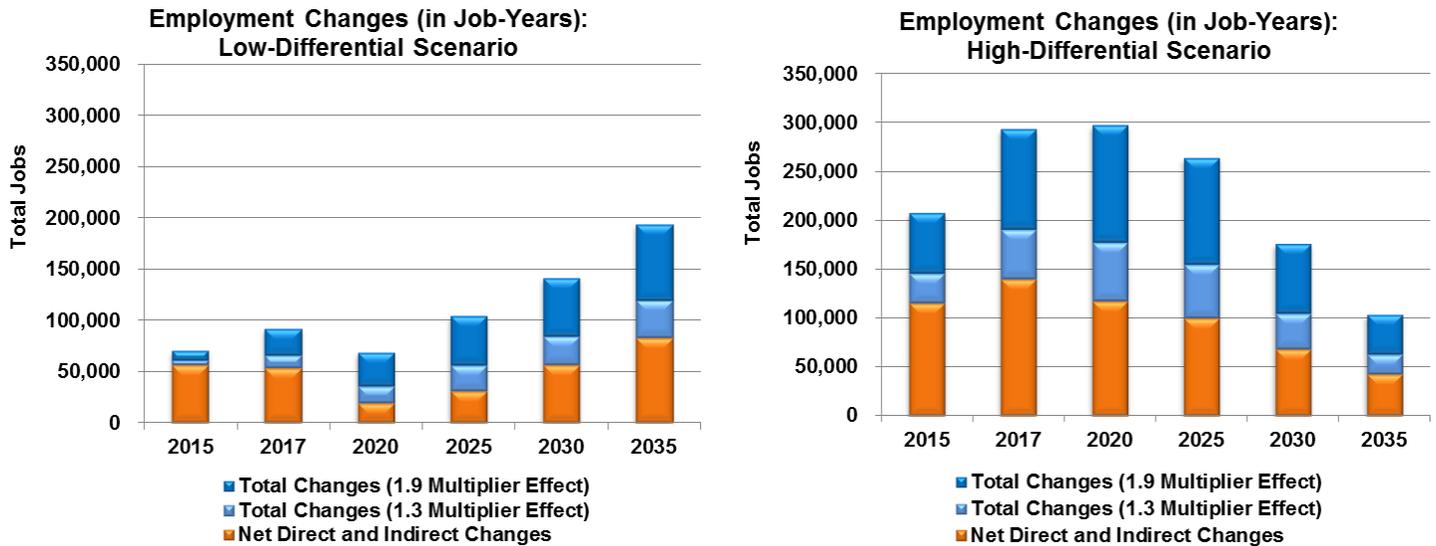
Note 1: Excludes multiplier effect (or induced) employment impacts.

Note 2: A job-year represents a single job occurring over 12 months or equivalent amounts of employment, such as two jobs occurring for six months each.

The exhibit below shows the total employment changes due to lifting the export restrictions. This includes the direct and indirect jobs, as well as the induced employment generated by the

additional consumer spending resulting from the direct and indirect jobs. Lifting the crude export restrictions results in a net employment gain of up to 118,000–220,000 annual jobs over the forecast period.¹⁵ The U.S. economy could gain as many as 300,000 jobs in 2020.¹⁶ As with GDP changes, employment changes between the Low-Differential and High-Differential scenarios are influenced greatly by the WTI-Brent price spread changes.

Exhibit 1-12: Total Employment Goes up when Crude Exports Are Expanded



Source: ICF analysis

Note 1: Multiplier effects can be higher when there is slack in the economy (not at full employment) and less when the economy is running near capacity. Hence, the estimated total employment impacts are shown as a range.

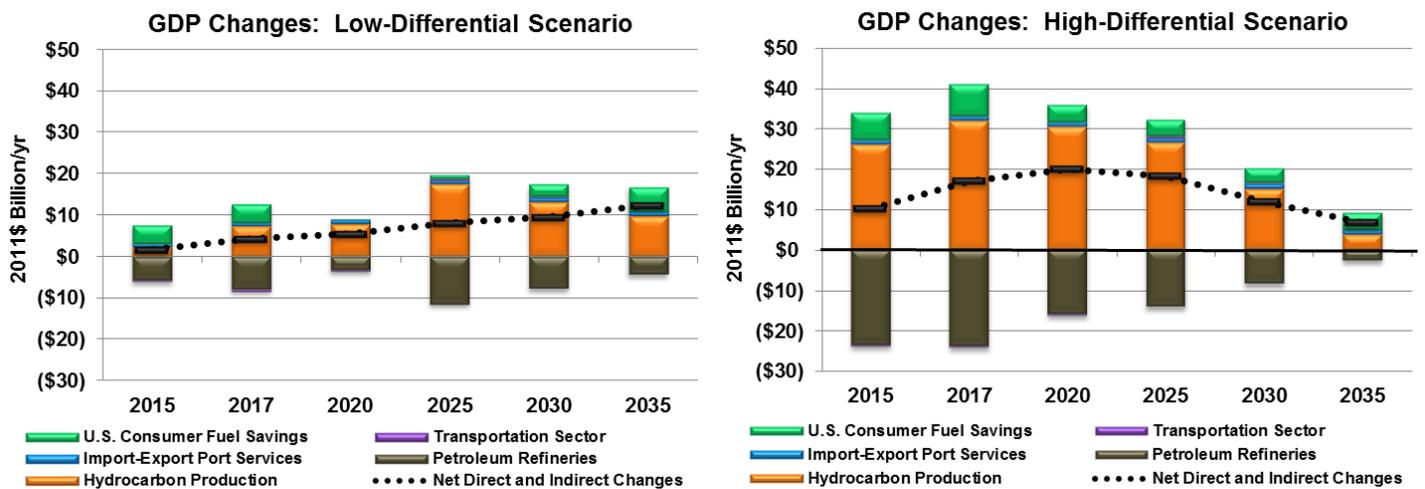
Note 2: A job-year represents a single job occurring over 12 months or equivalent amounts of employment, such as two jobs occurring for six months each.

¹⁵ Based on the 1.9 multiplier effect.

¹⁶ *Ibid.*

Crude exports cause GDP to increase an additional \$7.8 billion annually on average over the forecast period in the Low-Differential Scenario (direct and indirect), or \$14.3 billion annually in the High-Differential Scenario. The majority of direct and indirect GDP gains are in hydrocarbon production and consumer spending (due to lower domestic gasoline and other petroleum product prices). Included in the hydrocarbon production sector GDP changes are increased benefits to mineral-rights owners. Incremental impacts are due to both a projected increase in volume and a projected relative increase in price. Additional hydrocarbon production royalties average between \$2.0 and \$4.0 billion annually between 2015 and 2035, depending on scenario.

Exhibit 1-13: Allowing Crude Exports Adds to GDP (Direct and Indirect)



Source: ICF analysis

Note: Excludes multiplier effect (or induced) GDP impacts.

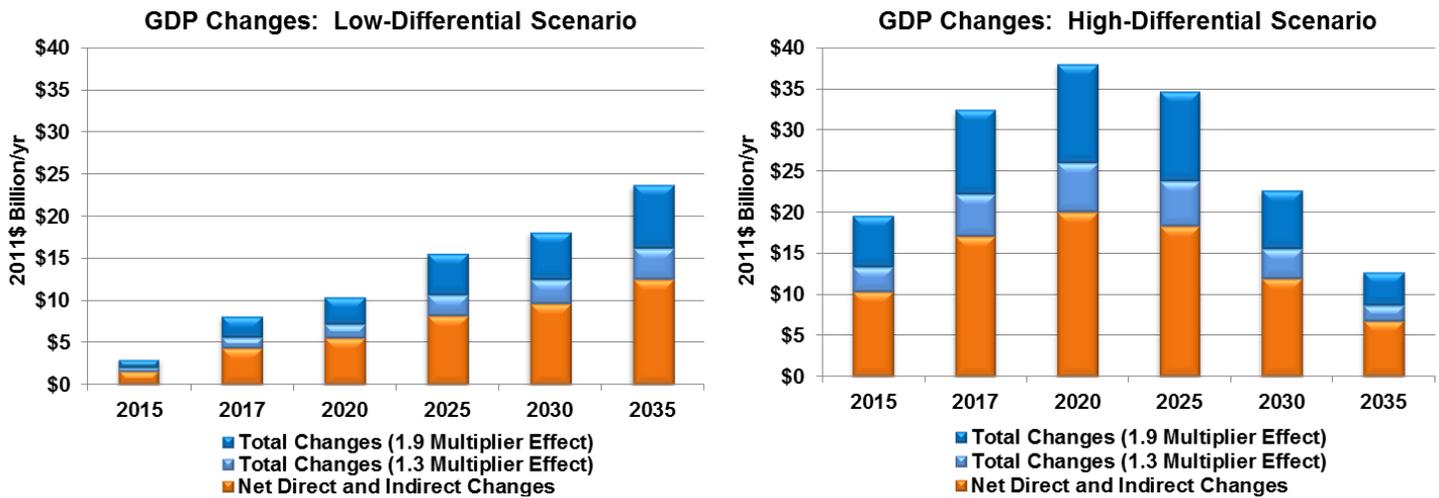
The main GDP offsets stem from the reduction in the calculated contribution to GDP from the petroleum refining sector. Higher domestic crude costs, coupled with slightly lower U.S. and global petroleum product prices result in lower refiner margins. It is important to note that the volume of refined product produced is similar in all cases. Therefore refinery operations, including employment, are not projected to be significantly affected due to crude oil exports. In fact, refinery throughput is projected to increase from current levels in all scenarios, with and without additional crude oil exports.

Total economic impacts include the direct and indirect GDP changes addressed above, as well as the induced impacts through the multiplier effect. The multiplier effect is due to additional consumer spending throughout the economy resulting from extra income from direct and indirect jobs and owners' income. Total (direct, indirect, and induced) GDP changes caused by the change in crude exports average up to \$14.8 billion annually in the Low-Differential Scenario and \$27.1 billion annually in the High-Differential Scenario over the 2015-2035 forecast period.¹⁷ Annual U.S. GDP is estimated to increase by as much as \$38.1 billion in 2020 if expanded

¹⁷Ibid.

crude exports are allowed.¹⁸ As explained above, the High-Differential Scenario has the largest WTI-Brent differentials in the early years when exports are restricted; thus, the GDP impacts of releasing crude exports are highest during the early years. The difference in GDP changes for the Low-Differential and High-Differential scenarios are determined by the WTI-Brent price differentials as discussed earlier.

Exhibit 1-14: Total GDP Increases when Crude Export Restrictions Are Lifted



Source: ICF analysis

Note: Multiplier effects can be higher when there is slack in the economy (not at full employment) and less when the economy is running near capacity. Hence, the estimated total GDP impacts are shown as a range.

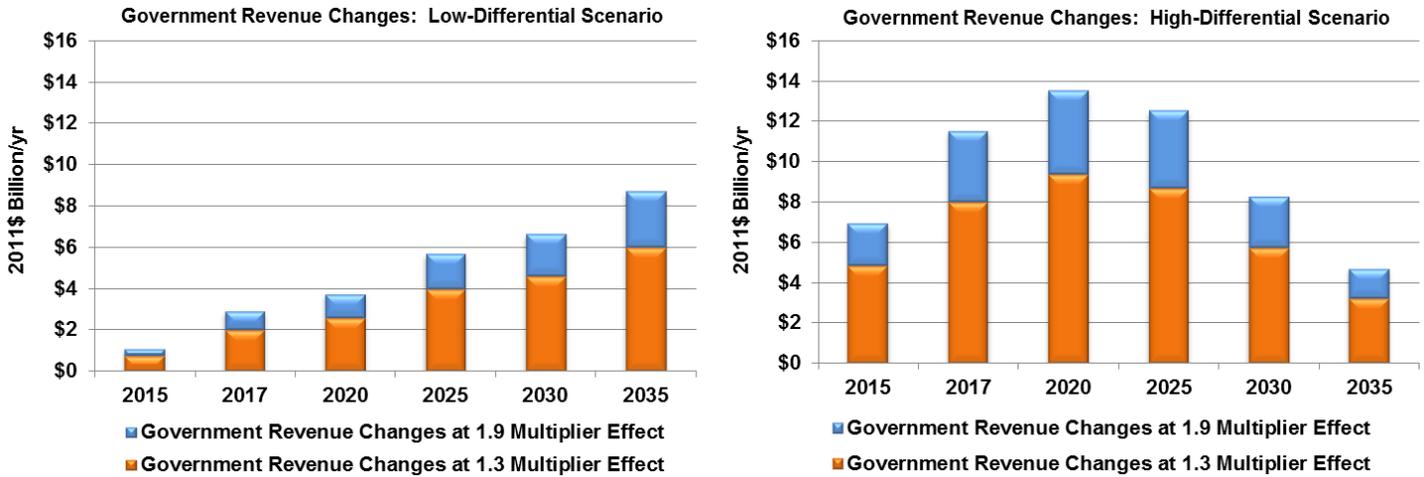
The exhibit below shows total government revenues from an expansion of crude oil exports. Government revenue increases include federal, state, and local tax receipts on the additional GDP generated, as well as from royalties on federal lands for additional crude oil drilling. Government revenue increases could reach \$13.5 billion in 2020 in the High-Differential Scenario, or up to \$3.7 billion in the Low-Differential Scenario.¹⁹ Government revenue

¹⁸ Ibid.

¹⁹ Based on the 1.9 multiplier effect.

increases average over \$5.4 billion annually over the forecast period in the Low-Differential Scenario, and near \$9.7 billion annually in the High-Differential Scenario.²⁰

Exhibit 1-15: Total Government Revenues Increase when Crude Export Restrictions Are Lifted



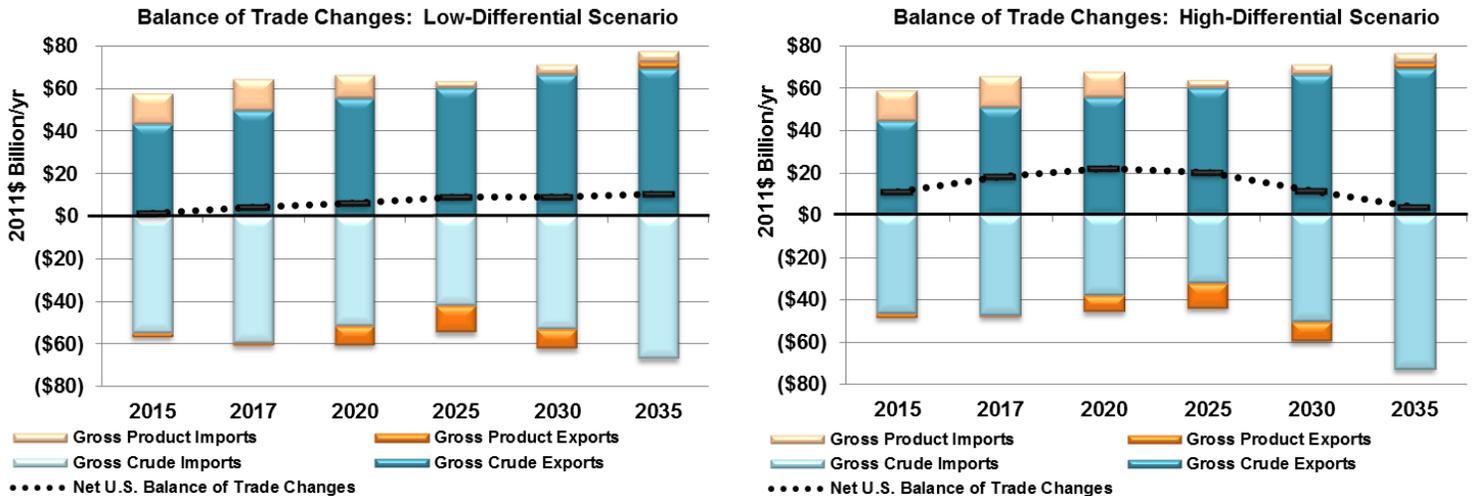
Source: ICF analysis

Note: Multiplier effects can be higher when there is slack in the economy (not at full employment) and less when the economy is running near capacity. Hence, the estimated total employment impacts are shown as a range.

²⁰ Ibid.

Lifting crude oil export restrictions contributes to expanded U.S. exports. Assuming all else equal, this could narrow the U.S. trade deficit by \$22.3 billion in 2020 through increased international trade of U.S. crude oil. The change in net exports of crude oil and petroleum products is expected to average \$7.6 billion in the Low-Differential Scenario and \$14.6 billion in the High-Differential Scenario over the period 2015 to 2035. The contribution to the U.S. trade balance from an expansion of crude exports is led by gross crude exports and an increase in net product exports.

Exhibit 1-16: Balance of Trade Changes due to Lifting Restrictions on Crude Exports



Source: ICF analysis

Note: Increases in gross import values shown as negative values, due to the negative impact on the U.S. balance of trade. This means that an increase in the gross import value (increasing the U.S. international trade deficit) is shown as negative, whereas a decrease in gross import value (decreasing the U.S. international trade deficit) is shown as positive.

1.5 Methodology

The fundamental purpose of this study was to assess the impacts of allowing crude oil exports on the U.S. economy and consumers. A first key step, therefore, was to quantify the volume of crude oil that could be exported economically from the United States if restrictions were lifted. The study simultaneously quantified the pricing impacts on domestic and international crude and petroleum product prices. These oil market projections were then used to assess the economic impacts to the U.S. economy of lifting the export restrictions. Because of the uncertainty in several factors that could affect near- and medium-term crude prices, ICF created a Low WTI-Brent Price Differential Scenario and a High WTI-Brent Price Differential Scenario. The High-Differential Scenario assumed that wider WTI-Brent price differentials are near recent levels for a longer period, relative to that assumed in the Low-Differential Scenario.

All commodity price projections are based on EIA's Annual Energy Outlook 2013 with adjustments due to ICF estimates on changes of supply and demand in each scenario.

In both scenarios, the study assumed that Keystone XL pipeline and the planned Enbridge cross-border expansion would be built, as well as three other major pipelines that export

western Canadian crude directly to the Canadian west and east coasts. Other assumptions regarding oil market conditions were primarily based on the 2013 U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) as adjusted by ICF forecasts for higher U.S. tight oil production and Canadian oil sands production. The results from this study were completed before the release of the EIA's AEO 2014 Early Release, although many parts of our forecast are consistent or of similar magnitude to the AEO 2014 Early Release, such as U.S. tight oil production forecast trajectories. In addition, the AEO 2013 High Resource Case is similar to the AEO 2014 Early Release Reference Case in terms of supply outlook.

The primary model used to perform the analysis of refinery operations and international trade in crude oils and petroleum products was the EnSys WORLD refining and logistics model. The WORLD Model projects international pricing across markets (based on an assumed world oil price) and employs freight costs between markets to effectively model global pricing and arbitrages in forecasting refinery operations. The study also employed ICF's proprietary models to estimate North American crude oil production as a function of oil prices and the effect of changes in crude oil production volumes on world crude oil marker prices and consumption of products.

As part of the analysis, ICF developed four cases (two market scenarios times two policy cases) of the global and regional mix of production and consumption of liquid fuels and for the world crude oil marker price (represented in the WORLD Model as Saudi Light crude). ICF used the international and U.S. national tables (Table 11 and 21) from the EIA 2013 Annual Energy Outlook (AEO) as the basis for these scenarios, combined with the conventional and unconventional production outlook from ICF's Detailed Production Report (DPR) model.²¹

The methodology ICF employed to estimate the economic consequences of lifting constraints on U.S. crude oil exports was similar to the methodologies used in our prior work investigating national and state-level economic impacts of liquefied natural gas (LNG) exports and increasing access to federal lands for oil and gas exploration and development. All these studies used an input-output model of the U.S. economy to determine how changes in outputs in certain sectors of the economy ripple through the U.S. economy to affect total GDP and employment.

²¹ See Appendix A for an overview of ICF's DPR.

2 Introduction

The U.S. Congress has limited crude oil exports since the mid-1970s.²² This was done to provide a measure of petroleum supply assurance in the face of declining domestic production, increasing demands for fuel, and growing dependence on foreign crude imports. Through the better part of the next 35 years, this Congressional action aligned with the economics of operating refineries to meet U.S. petroleum product demands and optimize return on refinery investment. U.S. refiners processed domestic crudes and modified refineries to turn cheaper grades of imported crude oil into clean products to meet domestic demand for petroleum products.

In recent years however, this situation has begun to change. U.S. demand for petroleum products stabilized at a lower level since the 2009 recession. Refiners maintained throughput by exporting excess refined product, most notably diesel fuel, to a growing global market. Increased domestic light crude supply in the midcontinent, increasing crude and condensate production in South and West Texas, and higher Canadian production created a crude surplus and depressed crude prices versus global markets particularly in Petroleum Allocation Defense District (PADD) 2²³ from 2011 onward. Imports are increasingly being backed out as more infrastructure is built to move crude and condensate to the Gulf Coast and to the East and West Coasts.

As these factors continue to evolve, the inability to export crude oil and condensate will likely begin to affect both producers' and refiners' ability to optimize their business. The U.S. refining system is geared to process much heavier crude than the rest of the world, and in particular to process heavier crudes than refineries in the markets that are most "reachable" from U.S. ports (e.g., Europe, Latin countries). Allowing crude oil exports may provide the United States the opportunity to export higher-valued light sweet crude oil while continuing to import heavier crude oils, including growing Canadian volumes, to fit the refinery system and at the same time potentially reducing the U.S. trade deficit.

The pace of crude oil and condensate production growth in the U.S. has been remarkable, and is transforming the crude transportation infrastructure and the conditions that impact the investment and operating strategies of producers, refiners, and midstream players. Refiners are doing everything to secure crude oil that is discounted in the market because of logistics constraints, with some refiners in the midcontinent reaping exceptional margins and coastal refiners struggling with rail economics to get some value from the cheaper domestic crude.

Producers are developing new and held-by-production (HBP) tight oil and condensate-rich leases quickly with new hydraulic fracturing techniques. Producers face challenges in delivering

²² The United States currently allows export of domestic crude oil in a few cases, such as the following: 1) from oil produced in Alaska's North Slope and Cook Inlet, 2) up to 25,000 barrels per day (BPD) in production from California's heavy oil fields, and 3) crude exports to Canada if the crude supplies remain in Canada or are re-exported to the United States. Other options are also permitted (e.g., exports of oil in exchange for strategic petroleum reserve volume) under defined conditions.

²³ PADD 2 consists of states mainly in the Central Plains and the Midwest including: Oklahoma, Kansas, Nebraska, South Dakota, North Dakota, Minnesota, Iowa, Missouri, Wisconsin, Illinois, Michigan, Indiana, Ohio, Kentucky, and Tennessee.

the crude to market at an adequate price to generate a return commensurate with needed investments and expenses. Midstream players have been moving to provide services to both producers and refiners. These services include rail facilities to load and unload crude, new terminals and pipelines to get crude to market, and facilities to export more and more products to foreign markets. In addition, the parallel growth in shale gas supply is providing U.S. refiners with an international advantage based on low cost natural gas for fuel and hydrogen feedstocks for refiners.

These changes are transforming the petroleum and petrochemical industries in the U.S., and at the same time, stimulating the economy by driving investments, jobs, and GDP growth at all points along the petroleum supply chain. Coupled with higher Canadian production of oil, domestic oil and condensate production growth have greatly reduced dependence on oil from outside North America.

Despite all these events, development of new tight oil/condensate production and completion of announced pipelines to move crude oil into the Cushing, Oklahoma hub and the U.S. Gulf Coast market increasingly indicate a significant overhang of light crude oil and condensate in the U.S. Gulf Coast region. This situation has a profound impact on both domestic and international markets, but is affected by a number of issues:

1. The pace of production growth in tight oil and condensate in various U.S. and Canadian plays, coupled with the rate of development in western Canadian oil sands. These, in turn, are affected by the resource endowment, technology improvements and exploration and production (E&P) economics. Private forecasters (including ICF) see U.S. crude and condensate production growing from 7.5 million barrels in 2013²⁴ to near 9 to 12 million barrels of oil per day (MMBPD) circa 2025. The EIA AEO forecast remains below these levels, but an alternative High Oil and Gas Resource Case reaches 10 MMBPD by about 2025 and remains near there through the last forecast year of 2040.²⁵
2. The alignment of crude production growth and new pipeline and rail capacity, particularly to coastal markets.
3. The level of refinery margins and possible investment requirements for refiners to process domestic crude oil/condensate and export products.
4. The impact of these changes on light and heavy crude oil spreads and refining optimization drivers.
5. The trends in U.S. demands for petroleum products in the face of Corporate Average Fuel Economy (CAFÉ) standards, Renewable Fuel Standard 2 (RFS2) obligations, and conservation efforts.

²⁴ U.S. Energy Information Administration (EIA). "Crude Oil Production." EIA, 13 March 2014: Washington, D.C. Available at: http://www.eia.gov/dnav/pet/pet_crd_crdpn_adc_mbbldpd_m.htm

²⁵ U.S. Energy Information Administration (EIA). "Annual Energy Outlook (AEO) 2013." EIA, April 2013: Washington, D.C. Available at: <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=0-AEO2013&table=19-AEO2013®ion=0-0&cases=ref2013-d102312a>

6. The impact of existing joint venture arrangements at Gulf Coast refineries with Mexico, Venezuela, and Saudi Arabia, which coupled with some other “puts” on foreign crude imports (mostly for lube oil production), create a “floor” for foreign imports. This is a critical assumption which may vary over the study period.
7. The sustained penetration of rail movements from various areas due to lack of alternative logistics and/or pipeline project delays, which make rail more viable. However, the rail economics are fluid and rely heavily on significant discounts from WTI and LLS to compete with waterborne light imports or even Eagle Ford movements to the East Coast. Today’s rail value to East and West Coast markets is far less than a year ago.
8. Finally, the ability, or continued lack of ability, to legally export any crude oil other than Alaska North Slope or limited amounts of heavy California crudes to markets other than Canada.

The analysis of all of these interrelated factors is complex. However, at the heart of the matter is the management of the volumes of crude that can be produced at various market prices. If world oil prices support continued hydraulic fracturing—and in Canada, continued oil sands development—crude supply possibly may outpace the midstream and refining sector’s ability to get it to market and process it. This could drive lower U.S. crude prices (but not lower product prices) and potentially a pull-back in production investment. The ability to export crude would allow producers to market crude to parties in other countries and could lead to higher netbacks for producers.

API has commissioned ICF International (in cooperation with EnSys Energy) to conduct a study of the economic impacts of changing U.S. government policies that prohibit most export of U.S. crude oils. This study provides the framework and sound economic analysis on the impacts of a liberalized crude export policy.

This report is organized into the following sections:

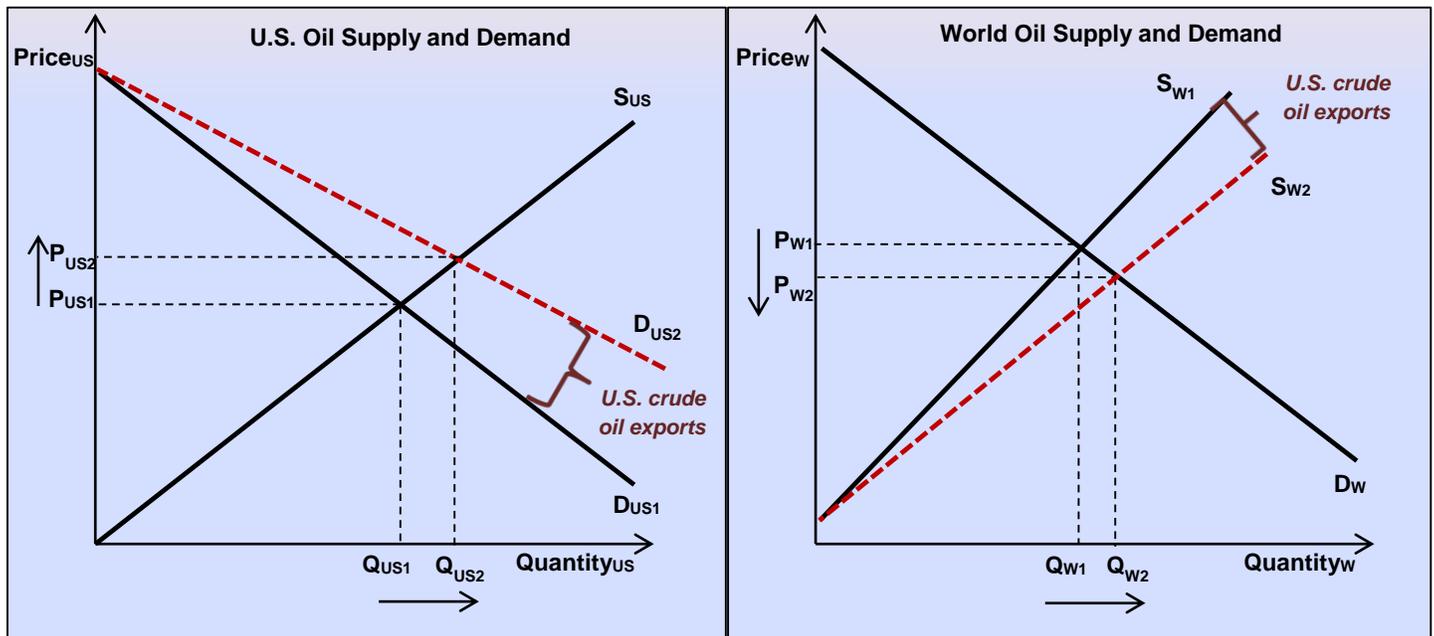
- Section 1: Executive Summary
- Section 2: Introduction
- Section 3: Study Methodology and Assumptions
- Section 4: Energy Impacts of Crude Oil Exports
- Section 5: Economic and Employment Impacts of Crude Oil Exports on the U.S. Economy
- Section 6: Bibliography
- Section 7: Appendices

3 Study Methodology and Assumptions

The fundamental purpose of this study was to assess the impacts on the U.S. economy and consumers of allowing crude oil exports, relative to a continuation of the restrictions on crude oil exports. A first key step was, therefore, to quantify the volume of crude oil that could be exported economically from the United States if restrictions were lifted and to simultaneously quantify the pricing impacts on domestic and international crude and petroleum product prices. These oil market projections were then used to assess the economic impacts to the U.S. economy of lifting the export restrictions.

The exhibit below illustrates the theoretical impact of lifting the crude export restrictions on U.S. crude oil supply and demand volumes and price changes (left-hand chart), as well as U.S. crude exports on global crude oil supply and demand volumes and pricing (right-hand chart). As shown in the left-hand chart, lifting the crude export restrictions increases demand for U.S. crude (i.e., expands demand for U.S. crude oil to include international trade demands). This shift in demand increases the U.S. crude oil price (from P_{US1} to P_{US2}), thus inducing an increase in U.S. crude oil production (from Q_{US1} to Q_{US2}). The right-hand chart illustrates the impact of additional U.S. crude production on the global crude oil market. The additional U.S. crude exports expand global crude oil supplies (from Q_{W1} to Q_{W2}). This supply increase causes global crude oil and petroleum product prices to decline (from P_{W1} to P_{W2}).

Exhibit 3-1: Conceptualization of Oil Supply and Demand Impacts of Removing Crude Export Restrictions
(Allowing Exports Increases Demand and Prices for Domestic Crude) *(Additional U.S. Crude Production Increases World Supply)*



3.1 Study Steps

In order to assess the energy, pricing, and economic impacts of expanding crude oil exports from the United States, this study used a number of models and assumptions that are discussed below. This study assessed the impact of lifting the crude oil export restrictions on U.S. crude oil supply-demand balance and the international supply-demand balance, both in terms of volumetric and pricing changes. The study compared supply-demand trends in a world with continued crude oil export restrictions to a policy case in which the restrictions are lifted. Because of the uncertainty in several factors that could affect near- and medium-term crude prices, ICF created two market scenarios:

Non-public Information

- A primary source of non-public data for this study was the WORLD refinery and petroleum logistics model built and maintained by EnSys Energy. WORLD contains proprietary data including information on refinery capacity by process, process performance characteristics, crude oil assays and refinery costs.
- The U.S. and Canadian oil production forecasts are based on proprietary ICF data for U.S. and Canadian tight oil play geologic descriptions, well performance characteristics and resource economics.
- Adjustments to AEO projections of world crude prices, demand and supplies were made by ICF to account for North American production volume differences with the AEO and difference among the scenarios presented here. These adjustments were made using proprietary ICF data, algorithms, and models.

- A Low WTI-Brent Price Differential Market Scenario (Low-Differential Scenario) – Assumed relatively rapid accommodation of light crudes and condensate, notably that the following would occur by 2015, leading to a narrowing in WTI-Brent differentials:
 - Continued swift buildout and availability of rail capacity to take Bakken and Niobrara crudes out to the U.S. East and West, as well as Gulf coasts.
 - Similar buildup in capacity to ship Eagle Ford crude and condensate via marine terminals at Corpus Christi, enabling expanded movements by sea to refineries in eastern Canada and the U.S. Northeast.
 - No constraints on fully backing out all light sweet crude imports into the Gulf, East and West coasts.
 - Similarly, a degree of flexibility in backing out medium sour crudes imported into the U.S., notably into the Gulf Coast.
 - Announced refinery projects to enable running light crudes all come on-stream by 2015 (but no further adaptations made by then).
- A High WTI-Brent Price Differential Market Scenario (High-Differential Scenario) – Assumed that inertial factors and delays would slow the adaptations to changing crude slate that were assumed in the Low-Differential Scenario, with the result that WTI-Brent differentials would remain wide, at least for several years. While some refiners have invested to process more light crude, others may be reluctant to risk significant capital on higher-cost refinery investments to accommodate lighter crude slates due in part to the uncertainty around crude export policies and the outlook for tight oil production growth. In addition, permitting requirements can adversely affect project timing and delay

implementation. These could prevent announced refinery projects from coming on-stream until after 2015. Equally, there could be delays in the implementation of the extensive list of announced projects for crude-by-rail capacity. Crude supply contracts in place and equity ownership stakes in refineries could slow the displacement of imported crudes by domestic grades. These factors would contribute to the wider WTI-Brent price differentials assumed in the High-Differential Scenario, thus prolonging U.S. crude price discounting relative to global prices.

Both the Low-Differential and High-Differential scenarios include two policy cases:

- Base Case (No Exports Policy Case) – Results based on the assumption that existing restrictions on crude exports remains in place.²⁶
- With Exports Policy Case – Results based on the assumption that all restrictions on crude exports are lifted.

The wider WTI-Brent price differential in the High-Differential Scenario assumes that refiners are slower to reconfigure refineries and change crude supplies to accommodate growing light oil supplies, thus prolonging the U.S. crude pricing discounting to global prices. While some refiners have invested in pre-flash towers²⁷ to process more light crude, many may be reluctant to risk significant capital on higher-cost refinery investments to accommodate lighter crude slates due in part due to the uncertainty around crude export policies and the outlook for tight oil production growth. In addition, permitting requirements are likely to adversely affect project timing and delay implementation. With crude exports, refiners do not have to make these refinery adjustments, so the Low-Differential and High-Differential with Exports cases are the same. A key focus throughout this report is on differential impacts between the export-restricted and non-restricted cases.

For all cases, this study assumes that the Keystone XL pipeline and the planned Enbridge cross-border expansion are built, as well as three other major pipelines that export western Canadian crude directly to Canadian west and east coasts. Other assumptions regarding oil market conditions are primarily based on the 2013 U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) as adjusted for higher U.S. tight oil production and Canadian oil sands production.

The primary model used to perform the analysis of refinery operations and international trade in crude oils and petroleum products was the EnSys WORLD refining and logistics model. Additional energy market impacts were derived from ICF databases and models used to estimate the U.S. tight oil and shale gas resource base size and economics, future tight oil

²⁶ This case assumed a continuation of current crude export policy in which the United States permits export of crude oil in a few cases such as the following: 1) from oil produced in Alaska's North Slope and Cook Inlet, 2) up to 25,000 BPD in production from California's heavy oil fields, and 3) crude exports to Canada if the crude supplies remain in Canada or are re-exported to the United States. Other options are also permitted (e.g., exports of oil in exchange for strategic petroleum reserve volume) under defined conditions.

²⁷ A pre-flash tower is a distillation tower that separates out the very light hydrocarbons from condensate or light crude oil so that the primary atmospheric distillation tower can process higher volumes of light oil without impacting condensing limitations.

production levels and North American crude oil logistics. A list of the key energy market and economic impacts estimated are listed in the exhibit below, along with the source or method of estimation.

Exhibit 3-2: Energy Market and Economic Impact Measures to Be Analyzed and Reported

Energy Market and Economic Impact Measures Analyzed and Reported	Source of Information
Base case world crude oil marker price (Brent, \$/bbl)	AEO 2013 oil price trajectory as adjusted downward for assumed higher levels of U.S. and Canadian oil production
World crude oil marker price for alternative cases (Brent, \$/bbl)	Reduction in world oil prices that is expected from allowing U.S. crude exports. This was estimated using supply-demand elasticity estimates derived from AEO sensitivity cases.
U.S. and Canadian crude oil supply costs (at various geographic points for various qualities, \$/bbl)	Product and crude supply costs were solved for within WORLD as differentials off of either base case or alternative marker crude price.
U.S. crude oil and condensate production by location and type	Taken from ICF Detailed Production Report (DPR). ICF has developed detailed crude/condensate resource base and cost estimates for major ongoing and emerging tight oil and liquids-rich gas shale plays. Volume of production will vary among model cases based on WORLD simulation results.
Crude oil and condensate assays	Assays for existing crudes from WORLD assay database.
Canadian oil sands crude oil production	Maximum oil sands production was based on Canadian Association of Petroleum Producers (CAPP) projection. Variation in production among cases due to oil price changes were based on logit-function investment logic whereby the probability of oil sands projects being made is reduced as Alberta bitumen prices fall.
Canadian conventional and tight oil crude oil production	Same as U.S. crude oil. That is, from ICF's DPR as adjusted by crude oil price changes.
Volume and value of U.S. exports of crude and condensate	Solved for within WORLD.
Volume and value of U.S. exports of petroleum products	Solved for within WORLD.
Capacity expansion and dollars investment in U.S. refinery throughput expansion	Solved for within WORLD.
Capacity expansion and dollars investment in U.S. refinery processing (condensate splitters, pre-flash distillation units, light naphtha isomerization units, heavy naphtha reformers, etc.) to accommodate more light crudes and condensates	Solved for within WORLD.
Investment in oil pipelines	Trade between PADDs solved for with WORLD. Canadian crude oil pipelines assumed to be constructed at fixed dates based on current schedules with some delays.
Investment in rail capacity	Based on WORLD results.
Investment in crude export capacity	Volume of exports from each PADD solved for in WORLD.
U.S. gasoline and other product supply costs	Solved for within WORLD. U.S. petroleum product imports and exports are not restricted and so costs are linked to world petroleum product costs.
U.S. petroleum product demand	Base case from EIA AEO 2013. ICF applied price elasticity to vary demand among cases.
World petroleum product demand	Base case from EIA AEO 2013. ICF applied price elasticity to vary demand among cases.
Consumer spending on non-petroleum products	Calculated as a function of product supply cost changes to petroleum products under assumption that money not spent on gasoline, diesel and home heating oil will be spent on other consumer goods and services.
U.S. refinery margin	Based on crude input costs and refined product prices calculated in WORLD.
GDP effects	Based on WORLD results, offline calculations and IMPLAN model. Calculate as value added in U.S. of final products whose output quantity has changed.
Employment effects	Based on IMPLAN model.
Government revenues	Based on IMPLAN model and offline calculations.
Balance of Trade Impacts	Calculated offline using WORLD results and other calculated values.
State-level GDP and employment estimates ²⁸	Calculated by allocating national-level results to states using allocation factors based on model results, announced plans, or historical activity by sector and state.

²⁸ State data is to be released as a separate supplement at a later date.

3.2 Overview of WORLD Model and Key Assumptions

The EnSys WORLD Model captures and simulates the total global “liquids” downstream system from crudes and non-crudes supply through refining, transport, and demand, and is used to address a wide range of strategic questions. The WORLD Model marries top down oil price/supply/demand outlooks, such as are developed by the U.S. Energy Information Administration (EIA), International Energy Agency (IEA), OPEC, and others, with bottom up detail. This detail includes approximately 200 crude oils; breakdown of non-crude supplies (natural gas liquids (NGLs); biofuels; gas-to-liquids and coal-to-liquids (GTLs/CTLs), etc.); data on every refinery worldwide with aggregation into regional or sub-regional groups; refining sector greenhouse gas (GHG) emissions factors; projects and investment costs; multiple product grades and quality specifications; and a detailed transport representation covering marine, pipeline and minor modes.

This formulation is used to model any current or future horizon out to 2035, simulating how the industry is likely to operate and react under any given scenario and capturing the interactions and competition inherent in the global downstream. WORLD is a “deterministic” model. This means that, within any one case, all projected supply and demand volumes are fixed essentially as inputs (except for the marker crude for which generally Saudi Light is used). Based on these and other inputs, WORLD in turn projects as outputs key industry parameters for the horizon being simulated, notably, global refining activities, investments and economics, crude and product pricing/differentials, trade flows, and logistics. Associated projections—such as for crack spreads (refinery margins), producer revenues and product regional supply costs—can readily be calculated. Across any case, the results are internally consistent: supply and demand must balance, crude exports must match imports and so on. The main version of the WORLD Model simulates the world broken into 22 regions with an emphasis on the U.S., which also includes more disaggregated refining groups than in other regions. In this study, the main focus in the WORLD Model cases was on U.S. crude oil exports, U.S. refining activity, and related market economics.

3.2.1 Import Floor Assumptions²⁹

The term “import floor” refers to the minimum quantity of imported crude oil that would be expected to take place due to joint venture arrangements, product quality requirement (primarily lubes), investment agreements and other factors that might limit or slow the price responsiveness of import volumes. This is represented in WORLD as minimum import levels that decline over time as these factors are expected to lessen in importance.

²⁹ All assumptions are based on publicly-available data either from company press releases or company presentations and ICF analysis of historical imports by refinery and volumes.

Exhibit 3-3 shows the decline in Gulf Coast (PADD 3) imports from 2012 through the first half of 2013 (H1). Not surprisingly the greatest decline has been in light crude (-50%) and medium crude (-13%). In comparison, heavy crude imports have declined about 8 percent.

Exhibit 3-3: PADD 3 Import by API Gravity Range

Crude Oil Type	Volume (KBPD)	
	2012	2013 H1
Heavy (≤ 25)	2,062	1,895
Medium (> 25 & < 35)	1,671	1,462
Light (≥ 35)	627	300
Total	4,360	3,657

Source: EIA and ICF analysis

The degree to which the light crude imports can be further reduced has a direct influence on the economic impacts of changing export crude policy. The higher the import floor is estimated to be, the faster and more severe will be the price-depressing effect of crude export restrictions and the greater will be the economic benefit to lifting those restrictions. The assumed crude import floors used in this study are described below.

PADD 1 (East Coast)

No floor was assumed given the degree of foreign light imports and lack of any substantive joint venture (JV) arrangements or crude commitments.

PADD 3 (Gulf Coast)

The confluence of domestic sweet crude into the Gulf Coast via Seaway and TransCanada Keystone (Cushing leg to Houston/Port Arthur), and volumes from Eagle Ford and the Permian via multiple new pipelines are assumed to continue the reductions in foreign imports into PADD 3. Canadian heavy will come into the market via Keystone XL/Enbridge projects based on construction scenario assumptions in the study for Canadian export pipelines. Alternatively, rail movements will take the place of dilbit, railbit, or bitumen (another important assumption).

There are currently several situations that support an argument for a floor on PADD 3 crude imports: 1) JV arrangements; 2) Lube Crude requirements and 3) investment links. The discussion below details all of these possible areas. The availability of light domestic crude and/or heavy Canadian should push the 2013 imports of 3.7 MMBPD lower as North American production growth backs out imports.

By the 2015 period, the production scenarios could drive PADD 3 imports down to a million barrels per day. However, the various issues discussed below could limit how far imports could be driven down. These issues include how Saudi Arabia reacts to U.S. markets, how other JV

arrangements push out imports or alter formulas to sustain imports, and how lube demands could be met. The exhibit below shows there already may be some “push out” of JV crudes. (Motiva Port Arthur import declines appear to be due to operational issues rather than price considerations.)

Exhibit 3-4: Import by Joint Venture Refinery

Joint Venture	Volume (KBPD)	
	2012	2013 H1
Motiva (Shell/Saudi JV)	331	301
Shell Deer Park (Pemex JV)	185	139
Citgo (Vz JV)	292	221
Chalmette (Vz JV)	63	42
Total	871	703

Source: EIA and ICF analysis

A floor of 2 MMBPD in PADD 3 by 2015, and 1 MMBPD by 2020 was assumed. The “buildup” to support these numbers was based on various companies’ press releases, investor presentations, and other public sources, along with ICF analysis of import trends from EIA, and is as follows:

- Three refineries have crude supply contracts with PEMEX for heavy crude (Maya) that were used to justify/finance new delayed cokers. It was assumed that these are netback deals wherein the refiner is protected from margin risk on the low side to offset some sort of minimum throughput commitment from the refiner to PEMEX. The three refineries are Valero at Port Arthur and Texas City, and ExxonMobil Baytown. It is assumed that 2013 volumes of PEMEX crude at these refineries will continue to be imported into the future.
- ExxonMobil and Citgo are known from EIA import data to import Mexican crude, primarily Olmeca, to produce solvent refined lubricant base stocks. For the short to medium term, it is assumed that these imports will continue. However, new WTI production from shale formations in the Permian Basin is increasing the volume of MCS-L (Midcontinent Sweet, Lube) components. As Permian Basin production increases, it is expected that the higher valued MCS-L components could be segregated and processed into lubricant basestocks, at the expense of Olmeca processing. The volume of Olmeca imported for lubricants is assumed in the study to decrease versus 2013 volumes by 25 KBPD in 2020 and 50 KBPD in 2025.
- Motiva (Shell/Saudi JV) would have been expected to increase imports of Saudi crude with completion of the Port Arthur expansion project. However, Motiva imports of Saudi crude have actually decreased between 2012 and 2013.
- Chevron Pascagoula has been importing Venezuelan heavy crudes such as Boscan for many years according to EIA data. Although Pascagoula is not directly connected to the

Houston area via pipeline, it is anticipated that barge volumes of dilbit and domestic sweet can substitute for a portion of the current import volume.

- Valero has publicly indicated that it is constructing crude topping units at its Houston and Corpus Christi refineries. This has the potential to decrease imports, especially to the Corpus Christi facility.
- Reversal of the Ho-Ho pipeline to allow crude oil movements from Houston to the Mississippi River refineries in Louisiana is expected to improve the logistics supporting the processing of sweet domestic crude in those refineries. Presumably, dilbit or other Canadian heavy crude oils can also be processed to maximize Coker loadings and gradually push down waterborne imported volumes
- Although Marathon has processed a significant volume of Saudi crude in the expanded Garyville, LA refinery, this plant is expected to be a major beneficiary of the reversed Ho-Ho line. Waterborne imports may have difficulty competing with the economics of a possible sweet domestic and dilbit blend as an alternative.
- Although the dissolution of the Phillips 66/PdVSA joint venture for the Sweeny refinery remains in arbitration, Phillips appears to be in control of the facility and decreasing Venezuelan imports based on EIA data. It is assumed that these volumes will continue to decrease as PdVSA withdraws support, further reducing the import floor.
- There have been no public reports of changes in the Deer Park JV between Shell and PEMEX; therefore, the imports of Mexican crude into Deer Park were assumed to be constant in the study.
- It is expected that Marathon Texas City will continue to decrease imports and rely more on domestic sweet crude.
- Citgo and Chalmette Refining joint ventures are not expected to change from an ownership perspective and therefore the waterborne imports to those plants were assumed to remain constant.
- Houston Refining was an early mover among U.S.G.C. refineries regarding processing Canadian heavy crude. It was assumed that heavy Canadian will continue to back out waterborne heavy crude imports, eventually to zero.

PADD 5 (West Coast)

Declining volumes of Alaska North Slope (ANS) and heavy California will likely require sustained imports. Potential key assumptions were:

- Minimum 200,000 for lubes at Richmond are assumed over the short term as an input in the model.
- Allow movement by rail of domestic (Bakken and WTI) as economic within known capacity investments (Tesoro/Savage, Puget refiners, Plains AA in CA, Valero Benicia, Shell Anacortes) plus limited further expansion.
- Movement of oil sands crude to California could be complicated by local opposition or a low-carbon fuel standard (LCFS) economic penalty and Assembly Bill (AB) 32. For

modeling purposes, we allowed oil sands by rail or marine (from Vancouver, British Columbia, or from Washington State).

3.2.2 Crude Oil Assay Assumptions

The crude oil assay refers to the chemical composition of a specific crude oil. Each type of crude has a specific combination of chemical characteristics that differentiate it from all other crudes. Assay analysis is used by refiners to assess the compatibility of certain crudes with the refinery specifications. Key factors include:

- API gravity – crude oil viscosity (lighter oils are less viscous than heavy oils)
- Sulfur content – sweet crudes have a sulfur content of less than 0.5 percent–1.0 percent, and sour crudes have a sulfur content above this range
- Boiling range fractionation – proportion of the crude oil that boils off at a specific temperature ranges.

Each refinery has a certain capacity for specific refinery products, with each boiling at a certain temperature. U.S. refineries are generally equipped to handle heavier crudes, which have more hydrocarbon chains that condense at higher temperatures (than do lighter oils).

Within an atmospheric column at a refinery, each petroleum product condenses at a certain temperature, with lighter products such as gasoline and diesel condensing at the top of the column, with heavier products such as residual and fuel oil condensing at the bottom. The atmospheric column is designed for a certain assay, with a specific capacity for heavy, medium, and light products. If the column is designed for medium/heavy oil, but light oil is used as the feedstock, there is not enough room at the top of the column for the light petroleum products to condense.

The crude oil slate refers to the proportion of oil that distills/condenses within a certain range. A specific slate will have an average API gravity. The U.S. production increases over the past five years have been primarily light oils, though U.S. refineries are configured to handle heavy oils. This means that the U.S. crude oil slate has become lighter, although refinery capacity to handle this lighter oil is limited. This study assumed that refiners can accommodate using lighter oils by up to one degree of API gravity without making refinery capacity adjustments.

3.2.3 Near-term U.S. Export Flexibility

For cases where exports are allowed in 2015, WORLD Model cases indicate total U.S. crude exports of up to 2 million b/d (MMBPD) may be economic. Exports are forecast to be sourced mainly from the Gulf Coast but also PADD 5 (split between Alaska; the Pacific Northwest; and Los Angeles, California) and PADD 1. Analysis of infrastructure in place and expected by 2015 indicates that these volumes should be logistically feasible. Discussion for each area is below:

PADD 1 (East Coast)

Crude is currently being exported from PADD 1 to Canada (Irving Oil) via railcars to Albany, New York and small tankers (300 MB) to St. John, Newfoundland and Labrador. Exports are roughly 0.1 MMBPD. There are several available sources for PADD 1 exports. Both the Global and Buckeye terminals in Albany receive railcars and outload crude oil—some to Irving but also to the Phillips66 refinery in Linden, New Jersey. Capability exists to increase these movements.

Moreover, Buckeye has purchased the former Chevron refinery site and terminal in Perth Amboy, New Jersey, which may be used to receive crude from Albany and load onto larger tankers for export. The former Yorktown, Virginia refinery is now owned by Plains All-American, and this facility has significant storage to receive railcars of crude and to export. The two operating Philadelphia refineries are expanding crude intake by rail and Enbridge Rail is starting a unit train facility to serve Philadelphia area refineries.

Overall, if the economics are right, PADD 1 has several pathways for crude exports. An export volume of 0.3 MMBPD in 2015 is judged to be reasonable with potential to expand beyond that in 2015 by perhaps another 0.10 MMBPD to 0.40 MMBPD if economically feasible.

PADD 3 (Gulf Coast)

There are several port locations in PADD 3 that are currently shipping crude oil (to U.S. and Canadian ports) or have the ability to do so.

Corpus Christi, Texas has emerged as the primary loading point for Eagle Ford crude oil and condensate onto marine transportation for 1) delivery to other U.S. Gulf Coast (USGC) and U.S. East Coast (USEC) refining centers or 2) export to refineries in eastern Canada. Jones Act vessels are required for domestic destinations whereas foreign flag vessels can be used for export to Canada. Numerous pipelines transport crude oil from the Eagle Ford production area to Corpus Christi for use by local refiners or for loading onto marine transportation. Our survey of publicly available information regarding terminals in Corpus Christi that handle crude oil yields an estimated export capacity of more than 0.8 MMBPD, assuming that domestic deliveries are decreased accordingly. The unfettered crude export scenario postulated by the WORLD Model anticipates roughly 0.8 MMBPD of Eagle Ford exports. (This is logical since Eagle Ford crudes are the lightest of the tight oil crudes and thus the least fitted to Gulf Coast refineries whose average historical crude intake has been close to 30 API.) Note that it is also possible to transport more Eagle Ford to Houston as an alternate location for Eagle Ford exports, so it is not believed that export volumes of 0.8 MMBPD are unreasonable given Corpus/Houston infrastructure.

Due to a flurry of pipeline and terminal construction activity the **Houston/Texas City/Freeport** area should be in a position to support export of significant volumes of crude oil. In addition to receipt of some Eagle Ford volumes, this region now serves as the terminus of the Seaway pipeline system which delivers WTI and other crude oils from Cushing, Oklahoma. When fully expanded, the Seaway system will be capable of delivering over 0.80 MMBPD of crude to two

separate dock locations for possible export. In addition, the Gulf Coast Pipeline (southern section of Keystone XL from Cushing) will be able to deliver crude oil to the Oil Tanking facility located on the Houston ship channel. This will require completion of the Houston lateral from the main Gulf Coast Pipeline and a short connector pipeline to the Oil Tanking facility, both of which are currently under construction. The Gulf Coast Pipeline is capable of delivering between 0.6 to 0.8 MMBPD of oil depending on the quality (domestic light versus Canadian heavy if the entire Keystone XL line is completed) via the Port Arthur line and the Houston lateral (in total).

Another prime exporting location is the Sun Logistics terminal in **Nederland, Texas**. This terminal is the terminus of the Keystone Gulf Coast line into Port Arthur. The terminal owner indicates that the facility has capacity to import up to 2.0 MMBPD of crude across five docks and to ship a similar volume of crude by pipeline, vessel or barge.³⁰ The ability to import 2.0 MMBPD by ship likely does not imply the ability to export a similar amount without some restrictions on import capability. Pipeline crude can be received into the Sun terminal from the TransCanada Gulf Coast pipeline, ExxonMobil's Pegasus pipeline, and the reversed Shell Houston to Houma line. Volumes delivered by Gulf Coast pipeline and Shell Ho-Ho to Sun Nederland may decrease volumes of crude oil available for export at other locations. Therefore, we have limited our estimate of Sun Nederland's current exporting capacity to 0.8 MMBPD.

The **Louisiana** terminals that would be suitable for crude oil exports in 2015 have limited capability due to the limited on-shore pipeline delivery capability to these terminals. Crude oil for export could be provided by the Shell Ho-Ho pipeline, but as with Sun Nederland, it would be at the expense of exports at other Texas locations. Pipelines to supply the Louisiana terminals with crude oil from the Midwest and from western Canada are in the discussion stage, but are not expected to be operational for the 2015 scenario (these could involve a Capline reversal or a Trunkline conversion³¹ from gas to oil).

The WORLD Model anticipates a total of about 1.2 MMBPD of exports in 2015 from PADD 3. We believe that there is sufficient capacity and optionality in the PADD 3 pipeline and terminal facilities to support this volume of exports. The capacity ICF/EnSys expects to be in place by 2015 is a combination of facilities currently in use, or under construction with completion dates prior to 1/1/2015.

PADD 5 (West Coast)

Current policy allows export of Alaska North Slope (ANS) crude.³² In addition to volumes from the North Slope, possible export sources on the West Coast in 2015 include Puget Sound, Port of Vancouver (Washington) and Los Angeles.

³⁰ Sunoco Logistics. "Nederland Terminal." Sunoco Logistics, 2014: Sinking Spring, PA Available at: <http://www.sunocologistics.com/Customers/Business-Lines/Terminal-Facilities/Nederland-Terminal/56/>

³¹ Thomson Reuters. "Energy Transfer Partners plans Bakken pipeline." Thomson Reuters, 7 March 2014: New York, NY. Available at: <http://www.reuters.com/article/2014/03/07/pipeline-projects-energy-transfer-idUSL1N0M41U320140307>

³² The current policy requires the crude to be exported on Jones Act vessels

Analysis of these options, based on information from various public sources, indicates the following:

- Exports from Puget Sound refinery locations are likely not feasible. The Magnuson Amendment would appear to preclude exports from Puget Sound, unless one of the refineries in the area should shut down.
- Tesoro and Savage are developing a project in Vancouver, Washington to receive railcars of domestic crude for transshipment by cargo to West Coast refineries. Assuming permits are granted, the intent is to have the capacity to load 0.36 MMBPD by late 2014. Vessel size may be limited to West Coast-sized vessels (300,000–400,000 barrels) due to draft restrictions and storage limits, but the facility would provide a viable export source if freight costs could be managed.
- Global Partners is currently receiving crude by rail at a former ethanol facility in Clatskanie, Oregon and then loading barges for delivery to West Coast refiners. The dock at this facility is capable of loading ocean going tankers and could be used for crude export if economic conditions warrant. There are also two small terminals in Tacoma, Washington that are currently receiving crude oil by rail for loading onto barges. These facilities also have the capability to load small tankers. The combined export capability for all three of these facilities is roughly 0.1 MMBPD, and the expected cargo sizes would be small.
- Exports from Los Angeles, California would require receipt of crude into Los Angeles via rail from Bakken, Niobrara, or West Texas markets. Plains All American owns a rail facility in the San Joaquin Valley to offload railcars and move crude down its pipelines into LA. This may have some capacity available due to declines in California crude production in recent years. However it is not clear how the crude may get to a vessel given relatively tight infrastructure in the ports of Long Beach and Los Angeles. The California Energy Commission is looking at other possible California obstacles that could impede exports.

In summary, export assumptions from PADD 5 in 2014 should include ANS as economically viable for export, plus an estimated 0.2 MMBPD from Vancouver, British Columbia; Portland, Oregon; and Tacoma, Washington sites that could double by 2025. Infrastructure may be developed in Los Angeles, or other locations such as Gray's Harbor in Washington State.

Overall

Export capacity in 2015—with existing and planned infrastructure for the United States—is estimated at about 3.6 MMBPD as shown in the exhibit below.

Exhibit 3-5: WORLD Forecasts of Exports and Estimated Export Capacity by PADD

Location	Volume (KBPd)		
	2015 Exports (No Exports Case)	2015 Exports (With Exports Case)	Estimated Export Capacity
PADD 1	55	55	400
PADD 3 Corpus Christi	134	862	900
PADD 3 Other	1	293	2,100
PADD 5*	–	200	200
U.S. Total	190	1,410	3,600

Source: EnSys Energy

* Designates that PADD 5 and U.S. totals and capacities do not reflect ANS exports from Valdez.

Note: The United States currently allows export of domestic crude oil in a few cases, such as the following: 1) from oil produced in Alaska's North Slope and Cook Inlet, 2) up to 25,000 BPD in production from California's heavy oil fields, and 3) crude exports to Canada if the crude supplies remain in Canada or are re-exported to the United States. Other options are also permitted (e.g., exports of oil in exchange for strategic petroleum reserve volume) under defined conditions. The "No Exports Case" assumes a continuation of the current crude oil export policy.

Canadian Export via U.S.

The ability to export Canadian crude from U.S. ports requires the crude to be segregated and not commingled with domestic crudes. In addition, the exporter must obtain a license to export. The ability to get a license requires the exporter to demonstrate that the crude has remained segregated. Several Canadian producers have also indicated feasibility of shipping oil sands by rail to the U.S. for export.³³ However, oil transported by the Keystone XL pipeline and other pipelines that ship heavier crude to the U.S. Gulf Coast are not expected to be exported in the near- to mid-term, since that area currently imports heavy and medium crude oil.

3.3 Overview of the AEO Forecast Adjustments Methodology and Key Assumptions

As part of the analysis, ICF has developed four cases of the global and regional mix of production and consumption of liquid fuels and for the world crude marker price (represented in WORLD as Brent crude). These cases were developed through an iterative process in which results for crude price differentials from the WORLD Model were fed into ICF models to estimate U.S. crude production and revised world crude oil price and supply/demand conditions. Those revised price and supply/demand volumes were then put back into WORLD to create a new projection of refinery throughputs, crude oil and petroleum product logistics, crude price differentials, and product prices.

ICF used the international and U.S. national tables (Table 11 and 21) from the EIA 2013 Annual Energy Outlook (AEO) as the basis for these scenarios, combined with the conventional and

³³ Ewart, Stephen. "Canadian producers eye profits through U.S. ports". Calgary Herald, 17 March, 2014: Calgary, AB. Available at: <http://www.calgaryherald.com/business/energy-resources/Ewart+Canadian+producers+profits+through+ports/9620681/story.html>

unconventional production outlook from ICF's DPR model. First, ICF estimated the demand and supply price elasticities for crude and petroleum products from available U.S. data for the 2013 AEO High Resource and Reference Cases and then used these elasticities to estimate global responses to increasing U.S. production, as in the EIA High Resource Case, in a multi-step process. Next the estimated regional data for the EIA High Resource Case became the basis to derive market forecasts for production levels used in this analysis, which were taken from ICF's Detailed Production Report and the Canadian Association of Petroleum Producers (CAPP).³⁴ The price of the world crude marker (Brent) each year equilibrated the global markets through an iterative process, while the prices of West Texas Intermediate (WTI), Western Canadian Select (WCS) and Eagle Ford crudes were used in the estimation of U.S. and Canada petroleum production using ICF's proprietary detailed production report (DPR) model.³⁵

3.3.1 Regional Liquids Production and Consumption Adjustments

EIA produces a summary regional detail in Table 21 for liquid consumption and production and petroleum production as part of the International Energy Outlook (IEO).³⁶ ICF used EIA scenario results for the years 2010 to 2035 for the Reference Case and the High Resource Case. These results for the EIA Reference Case include crude prices (\$2011/bbl and nominal \$/bbl) for Brent and WTI and volumes (MMBPD) including liquid consumption by region, liquid production by region, liquid production by type, and petroleum production by region. For the EIA High Resource Case, the results include crude prices and volumes only for the United States.

First, ICF estimated the missing results for the Table 21 for the EIA High Resource Case along with demand and supply price elasticities using a multi-step process.

1. Used the U.S liquids consumption and Brent prices from the two cases to estimate the demand elasticity of -0.23.
2. Used this elasticity to estimate regional and global liquids production for the High Resource Case.
3. Estimated global liquids production from the Reference Case plus the change in global liquids consumption from the Reference Case to the estimate for the High Resource Case developed above.
4. Estimated global petroleum production assuming that the difference between liquids production and petroleum production stays constant except for the U.S. where we used the Table 11 data.

³⁴ Canadian Association of Petroleum Producers (CAPP). "Crude Oil Forecast, Markets, and Transportation." CAPP, 5 June 2013: Calgary, Alberta. Available at: <http://www.capp.ca/forecast/Pages/default.aspx>

³⁵ U.S. Energy Information Administration (EIA). "Annual Energy Outlook (AEO) 2013." EIA, April 2013: Washington, D.C. Available at: <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=0-AEO2013&table=19-AEO2013®ion=0-0&cases=ref2013-d102312a>

³⁶ U.S. Energy Information Administration (EIA). "International Energy Outlook (IEO) 2013." EIA, July 2013: Washington, D.C. Available at: <http://www.eia.gov/forecasts/ieo/>

5. Estimated the supply price elasticity of 0.281 using Non-U.S. petroleum production and Brent prices.
6. Estimated regional petroleum and liquids production using the Reference Case petroleum production and difference between liquids production and petroleum production. For the United States, the difference between petroleum production and liquids production comes from the Table 11 data.

The estimated regional data for the EIA High Resource Case became the basis for the alternative price-differential scenario (High-Differential Scenario) and export policy cases. For each of the four cases, ICF calculated the Brent price of crude each year that equilibrated the global markets through an iterative process as follows:

1. Estimated the West Texas Intermediate (WTI), the Western Canadian Select (WCS), and the Eagle Ford (EF) crude prices using the Brent price for each year (see below).
2. Using the Brent price and the liquids demand elasticity, estimated the regional and global demand for liquids.
3. Using the Brent price and the supply elasticity, estimated the regional production for all regions except for the U.S. and Canadian oil sands production.
4. Calculated the production for the Canadian oil sands, which is set to the Canadian Association of Petroleum Producers 2013 forecasts (CAPP13) on production for the With Exports cases, and used the increase in oil sands production from ICF's Oil Sands Production Model and added to the CAPP13 production.³⁷
5. Using the change in the WTI price from the With Exports Case, estimated production for U.S. conventional production using the supply elasticity and ICF's DPR Reference Case production estimates.
6. Using the change in the EF price and WTI price for the Reference Case (Low-Differential Scenario), estimated the U.S. tight oil production.
7. Determined the amount that the global supply and demand is out of balance.
8. If the supply/demand balance was within an acceptable range, then the process was stopped; otherwise, ICF adjusted the prices and repeated.

3.3.2 Tight Oil Resource Base Assumptions

In recent years, the tight oil resource base in North America has emerged as a world-scale resource that has the potential to impact world oil markets, while generating thousands of high quality jobs in the United States and Canada. Because of activity in these plays, U.S. oil production is increasing rapidly, greatly reducing the need for imported oil and altering North American oil production and transport patterns and infrastructure development.

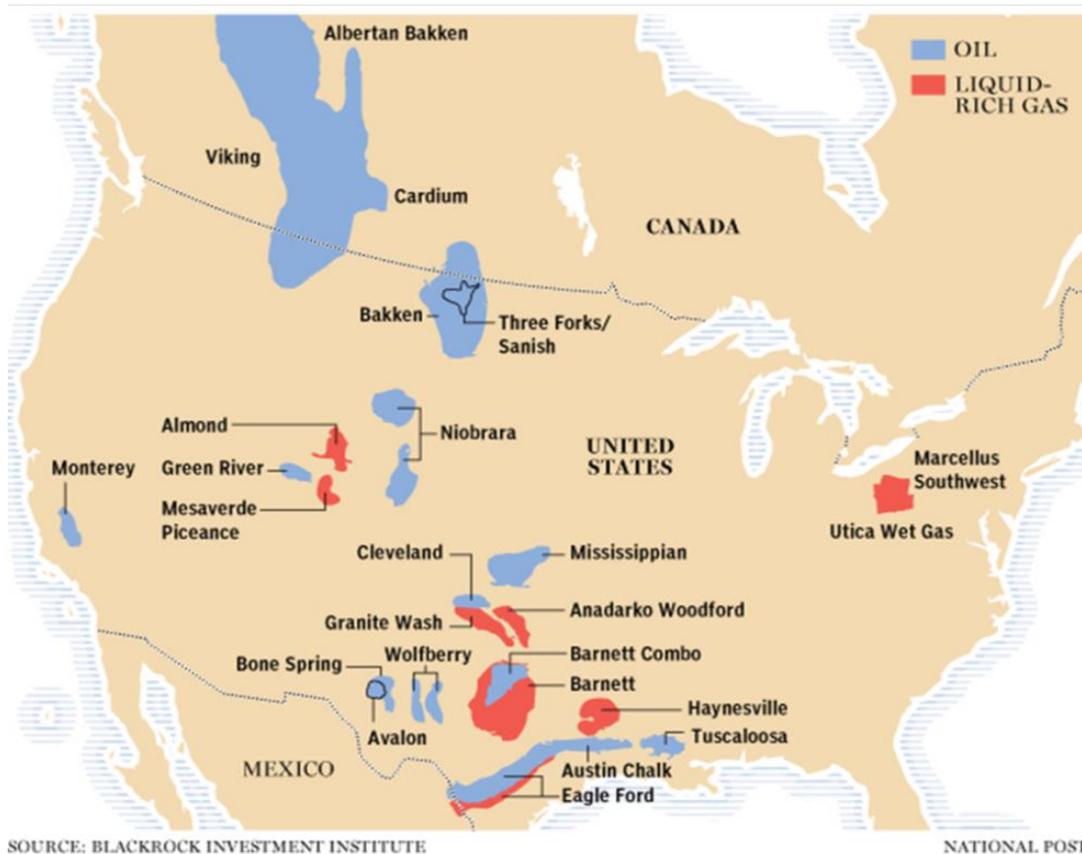
³⁷ Canadian Association of Petroleum Producers (CAPP). "Crude Oil Forecast, Markets, and Transportation." CAPP, 5 June 2013: Calgary, Alberta. Available at: <http://www.capp.ca/forecast/Pages/default.aspx>

To date, there has been scarcity of published analytical work assessing the scope and implications of this resource. A large amount of information has been published on individual plays in the areas of geology, drilling activity, well costs, economics, and prospectivity of company acreages. However, there is a need for a much better understanding of the scope and characteristics of future potential at the regional and national level. Such an analysis must consider geologic variability, drilling costs, and economics.

ICF International has developed an assessment of the technically and economically recoverable tight oil resource base of the United States and Canada. That assessment underlies the forecast shown in this report. The assessment is primarily based upon ICF analysis of public domain maps and data, with the information processed through a proprietary tight oil assessment and economics model.

Tight oil production from plays such as the Bakken Shale in the Williston Basin, the Eagle Ford Shale in South Texas, the Niobrara in the Denver Basin, and various plays in the Permian Basin of West Texas and southeastern New Mexico has become a major component of U.S. oil production. A map of the major North America tight oil and wet gas plays is shown in the exhibit below. (On this map, tight oil and wet gas is shown in light blue. Western Canada tight oil is more localized than shown here). The geographic extent of known North America tight oil is vast, extending from the Gulf of Mexico to the northwestern regions of Canada. In the East, a vast area of wet gas is present in the Marcellus and Utica shales, and in California, the Monterey Shale holds large resources.

Exhibit 3-6: Distribution of North America Tight Oil



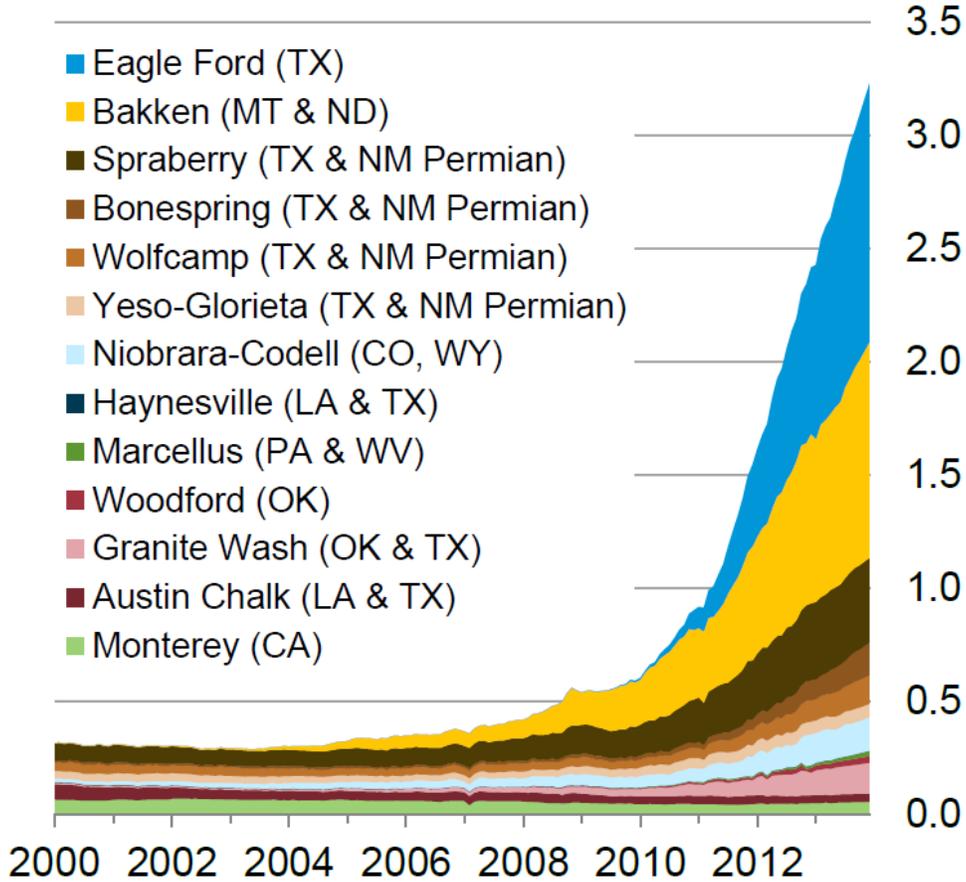
Source: Blackrock Investment Institute

The exhibit below presents the EIA analysis of U.S. tight oil production through 2013. The plays included in the chart produced 3.2 million barrels per day of liquids at year-end 2013. Total annual crude and condensate production in the U.S. in 2012 was 2.37 billion barrels or 6.48 MMBPD, up from 5.65 MMBPD in 2011. Tight oil production represents a large and rapidly growing fraction of U.S. oil production.

U.S. tight oil production is predominantly from two plays: the Williston Bakken and the Texas Gulf Coast Eagle Ford. However, production in West Texas is increasing rapidly as well, and the in-place resources in that region are tremendous due to stacking and thickness of the various oil-bearing geologic formations.

The chart includes both crude and lease condensate production. Other, crude and condensate volumes are not reported separately by state agencies. Lease condensate represents the liquids that separate from the gas stream at the well site. Much of the Eagle Ford Shale liquids production to date has been condensate, because the wet gas portion of the play has been prolific. The crude oil fraction of Eagle Ford liquids is increasing rapidly, however. Almost all of the U.S. tight oil production is considered “light” (relatively high gravity) and “sweet” (low sulfur).

Exhibit 3-7: U.S. Tight Crude and Condensate Production (Unit: MMBPD)



Source: EIA presentation by Adam Sieminski, January 22, 2014

Assessment Approach and Models Used

The objective of the ICF assessment was to evaluate major tight oil plays by using public domain information on geology and well characteristics. ICF completed the analysis of 32 North American shale gas plays using a GIS framework. That work involved the Geographic Information System (GIS) mapping of depth, net thickness, organic carbon content, and thermal maturity of each play. It also included an ICF survey by operator of typical well costs and productivity parameters. These data were imported into ICF models to generate the resource assessment and play economics at a highly granular level.

The GIS shale gas study focused on gas, but in doing so also included the oil portion of plays such as the Eagle Ford, Barnett, and Anadarko Woodford. It did not cover tight oil in the “oil-well” plays such as the Bakken and Permian Basin, nor did it cover some other tight oil plays that include gas wells such as the Denver Niobrara.

ICF typically assesses tight oil plays on the basis of mapped “cells” or sub-plays, typically ranging from 5 to 10 cells per play. For each play, the following information was either obtained from published geologic maps or company data or was estimated.

Parameters for each cell from map or other sources of information:

- Mapped play area
- Average vertical depth
- Average net pay thickness
- Thermal maturity (vitrinite reflectance or R_o)
- Organic carbon content (TOC)
- Porosity (generally estimated)
- Temperature and pressure gradients (often estimated for regional data)
- Well productivity characteristics (from historic production data and company slides)
- Lateral length and hydraulically fracture half length

Estimated factors:

- Thickness of brittle units (sandstone or limestone) within the shale formation
- Conversion efficiency of organic matter (for oil-in-place calculation)
- Risk factor applied to assessment (percent of area ultimately productive). The risk is assumed to be much lower in portions of the play that are productive.

The information for each play was input into the model to develop the estimated oil and gas in place (original oil in place, OOIP; and original gas in place, OGIP) and of technically recoverable resources. The output includes technically recoverable crude and condensate, dry gas, and gas plant liquids on both a risked and unrisked basis. Model output also includes the number of potential wells and average well recovery by cell.

Results of the Analysis of Technical Recovery

The exhibit below presents the results of the assessment and shows which plays are included. A total of 32 North American plays have been evaluated. Twenty-four plays have been assessed using the models and eight plays currently have estimated resources based on generalized factors. Plays with estimates include the Three Forks and Heath in the Williston basin and the Gulf Coast Tuscaloosa shale. These estimates are generally based upon play area, well spacing, and average recovery per well—not mapped geologic parameters. A risking approach is applied to the process to compensate for uncertainty in productivity and resource quality. In general, higher risk is applied to outlying areas of plays that have yet to be developed significantly.

The exhibit below summarizes the current assessment of risked, recoverable resources. The assessment presented in the exhibit represents technically recoverable resources from the initial well spacing only, and assuming current technology. Resources in place and infill potential are discussed below as well.

U.S. primary spacing tight oil potential is assessed at 60.9 billion barrels of liquids and 189.9 trillion cubic feet (Tcf) of associated gas. (Of the 60.9 billion barrels, about 54 billion barrels is from ICF-assessed GIS plays and 7 billion barrels is from plays with estimates). Western Canada tight oil is assessed at 20.3 billion barrels of liquids and 114.4 Tcf of gas. The natural gas portion of the assessment shown here consists of both associated gas in the crude oil portions of plays and gas well gas in the wet gas portions. A large fraction of the total gas resource comes from wet gas areas of plays such as the Eagle Ford, Utica, and Duvernay. The Duvernay is the dominant tight oil/wet gas play in Western Canada in terms of recovery, based upon our mapping and assumptions, and represents the majority of the assessed Canadian gas from tight oil.

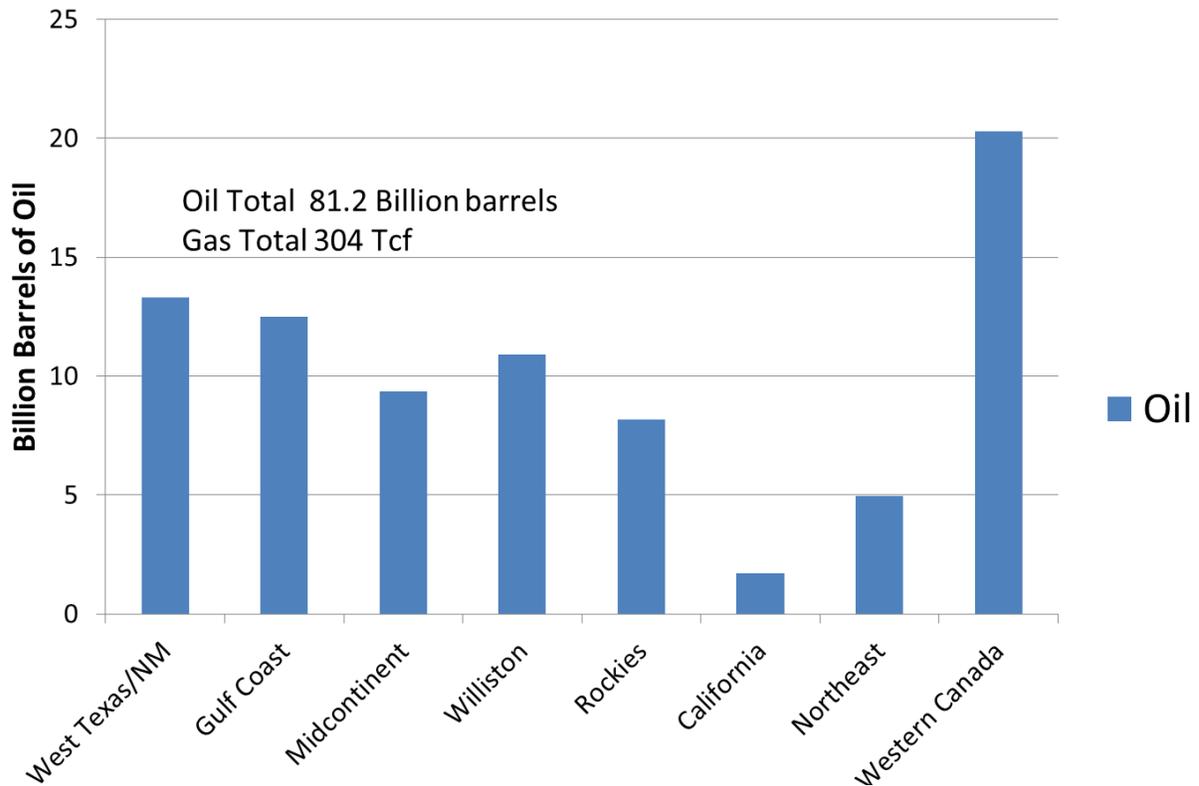
Exhibit 3-8: North America Assessment Summary

Region	Crude/Cond. Billion Barrels	Dry Gas Tcf	Region	Crude/Cond. Billion Barrels	Dry Gas Tcf
West Texas/NM	13.3	33.0	Rockies	8.2	48.8
Avalon			Denver Niobrara		
Bone Spgs.			Other Niobrara		
Wolfberry					
Cline			California	1.7	13.8
			Monterey		
Gulf Coast	12.5	36.7	Kreyenhagen		
Eagle Ford					
Austin Chalk			Northeast	5.0	17.6
Tuscaloosa			Utica		
Woodbine					
Midcontinent	9.4	25.1	WCSB	20.3	114.4
Anadarko Woodford			Bakken (Canada)		
Mississippi Lime			Cardium		
Fort Worth Barnett			Viking		
Smackover Brown Dense			Duvernay		
Anadarko Hogshooter			Montney		
			Minor plays		
Williston	10.9	14.9	US Totals	60.9	189.9
Bakken (US)			Canada Totals	20.3	114.4
Three Forks			North America Totals	81.2	304.3
Heath					

* Minor plays are Shaunavon, Ameranth, Pekisko, Exshaw, Slave Point, and Beaverhill Lake

Source: ICF International

Exhibit 3-9: North America Regional Tight Oil Current Technically Recoverable Based on Initial Well Spacing



Source: ICF International

Original Oil-in-Place (OOIP) and Recovery Factors

The ICF tight oil resource assessment relies upon an assessment of original oil-in-place, to which recovery factors and risk factors are applied. Recovery factors (recovery as a percentage of oil-in-place) can be used to check the reasonableness of resource estimates, assuming current technology or advanced technology plus infill potential recoverable resources.

The exhibit below summarizes U.S. original oil-in-place for conventional oil reservoirs and tight oil resources. The oil volumes for conventional oil reservoirs are based upon a study of CO₂ enhanced oil recovery (EOR) potential conducted for the U.S. Department of Energy.³⁸ The OOIP for tight oil is from the ICF assessment. The exhibit below indicates that U.S. conventional OOIP is 595 billion barrels and tight oil OOIP is 1,936 billion barrels. Thus, conventional OOIP is only 24 percent of total OOIP.

³⁸ U.S. Department of Energy National Energy Technology Laboratory, 2008, "Storing CO₂ with Enhanced Oil Recovery," <http://www.netl.doe.gov/kmd/cds/disk44/D-CO2%20Injection/NETL-402-1312.pdf>

The middle portion of the exhibit summarizes what has been discovered and proved through 2011 (the latest year of EIA reserves data). This volume, based upon ICF analysis of historic U.S. production, totals 220 billion barrels of crude oil, of which 194 billion barrels is past production and 26.5 billion barrels of remaining reserves. Assuming none of the 220 billion is tight oil (though a portion of it is – primarily the Bakken and Permian), this would represent a recovery factor of 37 percent of conventional OOIP. The overall perspective from this analysis is the tremendous volume of in-place resources associated with tight oil.

Exhibit 3-10: U.S. Oil-in-Place and Proved Recovery

		Billion barrels of oil		
Category	Source	AK	L-48	Total
Conventional OOIP	DOE study for CO ₂ EOR	67	528	595
Cumulative Production and Proved Reserves (Through EOY 2011)				
	Cumulative production	17.3	176.6	193.9
	Proved reserves	3.8	22.7	26.5
	Ultimate recovery	21.1	199.3	220.4
Ultimate Recovery as a Percent of Conventional OOIP		31.5%	37.7%	37.0%
Tight Oil OOIP *	ICF	0	1,936	1,936
Total assessed U.S. OOIP		67	2,464	2,531
Conventional OOIP as percent of total OOIP				24%

* AK tight oil not assessed.

Source: Compiled from various public sources by ICF International

Volume of Tight Oil Developed in Forecast

The tight oil production forecast through 2035 developed for this study is based upon the ICF tight oil recoverable resource base, as well as economic factors and other considerations. It is useful to summarize what is developed in the forecast relative to the total recoverable resource base and tight oil OOIP. This is presented in the exhibit below. The exhibit shows the OOIP, the risked current technology initial spacing resource, the risked current technology infill resource, and the risked advanced technology infill resource. The latter is the resource base used for the long-range forecast. The recovery factor for the risked, advanced technology resource base is 5.4 percent of OOIP (risked recoverable divided by unrisked OOIP). A total of 46 billion barrels of tight oil is developed in the forecast through 2035, representing 44 percent of the assessed recoverable resource.

Exhibit 3-11: ICF Tight Oil Resources and Portion Developed in Forecast

	Billion Barrels *
Original in-place tight oil resource	1,936
Risked current technology recoverable resource - initial spacing	53.9
Risked current technology recoverable resource - with infill	86.2
Risked advanced technology recoverable - with infill + technology advancement	103.8
Risked advanced technology recovery factor	5.4%
Resource developed through 2035	46.0
Percent of recoverable resource developed through 2035	44.3%

* The resources here exclude a number of plays with estimates only, whose resources are included in the ICF total assessed tight oil resource base.

3.4 Economic Impacts of Crude Oil Exports

The methodology ICF employed to estimate the economic consequences of lifting constraints on U.S. crude oil exports was similar to the methodologies used in our prior work investigating national and state-level economic impacts of liquefied natural gas (LNG) exports and increasing access to federal lands for oil and gas exploration and development. All these studies used an input-output model of the U.S. economy to determine how changes in outputs in certain sectors of the economy ripple through the U.S. economy to affect total GDP and employment. The economic impacts methodology consisted of the following six steps.

1. *Assessed the volumetric and pricing results from the WORLD Model and other adjustments for each of the following cases:*

Low-Differential Scenario:

No Crude Oil Exports Case³⁹

With Crude Oil Exports Case

High-Differential Scenario:

No Crude Oil Exports Case⁴⁰

With Crude Oil Exports Case

³⁹ This case assumed a continuation of current crude export policy in which the United States permits export of crude oil in a few cases such as the following: 1) from oil produced in Alaska's North Slope and Cook Inlet, 2) up to 25,000 BPD in production from California's heavy oil fields, and 3) crude exports to Canada if the crude supplies remain in Canada or are re-exported to the United States. Other options are also permitted (e.g., exports of oil in exchange for strategic petroleum reserve volume) under defined conditions.

⁴⁰ *Ibid.*

2. Translated energy market results into direct and indirect GDP effects

These effects, which are the immediate or “first round” effects on demand and output of goods and services in the U.S. economy, include economic changes brought on by a change in crude oil export policy, including:

- An increase in hydrocarbon production (including crude oil, lease condensate, natural gas, and natural gas liquids (NGLs))
- Changes in petroleum refinery throughput, margins, revenues
- Changes in consumer fuel expenditures due to changes in petroleum product prices
- Changes in import-export port fees due to changes in crude oil and petroleum product imports and exports
- Changes in the transportation sector due to a change in crude oil flows

In calculating these impacts, ICF first determined the physical unit and dollar value change in demand/output for the final products. The change in GDP was calculated as the value of the final product minus the estimated contribution from imported intermediate goods. Only changes in final products are counted toward changes in GDP to simplify the calculations.

3. Assessed the direct and indirect employment impacts

The direct and indirect value added GDP changes, as well as employment changes, and taxation were calculated using input-output relationships developed with the Impact Analysis for Planning (IMPLAN) Model of the U.S. economy. This input-output (I-O) model is based on a social accounting matrix that incorporates all flows within the U.S. economy. This model is used to assess the aggregate economic impacts associated with changes in an industry’s output, such as the impact of crude oil exports on the U.S. economy. For example, additional crude oil exports will require additional crude oil production services, equipment, and materials.

Those direct impacts will be followed by indirect impacts as intermediate inputs such as steel production to make casing and iron mining to make steel, which will also see higher demand. These I-O relationships can be extracted into matrices that show the number of direct and indirect jobs in sector X per million dollars of output in sector Y. This matrix is also defined as the number of direct and indirect jobs in sector X per physical unit of output in sector Y. Similar matrices can be constructed showing the GDP value added in sector X per million dollars or per unit of production in sector Y. With these matrices, ICF estimated the value added and job impacts by sector for the changes in economic and employment impacts attributable to crude oil exports.

4. Assess the induced economic activity

Apply a range of multiplier effects to the direct and indirect GDP changes to estimate the induced economic activity. Induced economic activity is generated as employees in direct and indirect activities, such as oil production or steel manufacturing spend their income. There is a great deal of uncertainty as to the induced economic activity generated. Thus,

ICF applied a range of multiplier effects. This estimate of additional GDP is referred to as the “induced GDP effect.”

The range in multiplier effects represents uncertainties regarding the possible future “slack” in the economy and how much of a “crowding out” effect there might be in factor⁴¹ markets if the new demands for labor and other factors stemming from crude oil exports cannot be met entirely with new workers and other factors.

The range spans from a lower-bound of 1.3, representing significant crowding out effect, to an upper-bound of 1.9, which is consistent with a very slack economy and/or an elastic supply of labor and other factors of production. This range is based on previous ICF efforts. This range indicates that every \$1.00 of direct and indirect economic activity generated leads to additional induced economic activity of \$0.30–\$0.90.

Estimation of Multiplier Effect

This study employs a range of multiplier effects to estimate the lower-bound and upper-bound for “induced” activities in the U.S. economy, resulting from the spending of personal income generated by the direct and indirect activities. The equation below shows the hypothetical GDP multiplier effect from any incremental increase of purchases (from business investment, exports, government spending, etc.) MPC is marginal propensity to consume, and is estimated at 0.900 using a post-World War II average for the U.S. This means that for every dollar of personal income generated, \$0.90 goes toward consumption, and the remaining \$0.10 is saved. The MPI is the marginal propensity to import, estimated at 0.162, based on the average for recent years. The effective tax rate is \$0.269 per dollar of income/GDP. Inputting the MPC, MPI, and tax rate into the equation below shows that every dollar of income stemming from direct and indirect activity hypothetically could produce a total of \$1.984, meaning that \$0.984 is “induced” economic activity, or the amount produced as the multiplier effect.

$$\Delta GDP = \Delta Exports * 1 / (1 - MPC * (1 - TAX) + MPI)$$

Multiplier Effect Input	Value
Marginal Propensity to Consume after Taxes (MPC)	0.900
Marginal Propensity to Import (MPI)	0.162
Tax Rate	0.269
Resulting Multiplier	1.984

Because of this uncertainty in the multiplier effect, a range is used in this study. A value of 1.9 is used as the multiplier for the upper-bound limit, and 1.3 [1.6 – (1.9-1.6)] for the lower-bound estimate.

Source: American Clean Skies Foundation (ACSF), based on analysis conducted by ICF International. “Tech Effect: How Innovation in Oil and Gas Exploration is Spurring the U.S. Economy.” ACSF, October 2012: Washington, D.C. Available at: http://www.cleanskies.org/wp-content/uploads/2012/11/icfreport_11012012_web.pdf

5. Assessed the induced employment activity

The GDP impacts (direct and indirect alone *versus* direct, indirect, and induced) are then converted to employment impacts using input-output relationships, wherein the number of jobs per dollar of value added vary among economic sectors. The net result of crude oil

⁴¹ Factors of production are defined by economists to be inputs such as labor, land, capital, materials, energy, and technical knowhow that are used in producing goods and services.

exports would be an increase in the demand for labor. In theory, this additional demand could be accommodated by the following processes:

- i. Reduced unemployment – those in the labor force who are actively searching for employment, but remain unemployed). This method of adjustment is most prominent during time characterized by high unemployment rate.
- ii. Increased labor participation rates – characterized by more people joining or remaining in the labor force due to higher wages and less time needed to obtain employment.
- iii. Longer hours worked – employed persons will work longer hours, such as moving from part-time to full-time employment.
- iv. Greater immigration – more foreign-national workers come to or remain in the United States.
- v. Crowding out – the sectors with growing demand will increase wages to incentivize workers to leave current jobs. The sectors losing workers then could adjust by substituting capital or other factors of production for labor and/or by reducing their production levels).

The input-output approach used in this study assumes that processes i to iv above will be dominant, and that the demand for more workers in oil-related sectors will be met to a large degree without constraining other sectors.

6. *Estimated government revenues and balance of trade impacts of crude oil exports.*

Government revenue increases due to crude exports are led by an increase in federal, state, and local tax receipts due to the increase in GDP changes, as well as a slight increase in federal land royalties for hydrocarbon production.

The balance of trade impacts arise from the value of crude oil and petroleum product exports, based on prices derived from the WORLD Model and ICF's alternative methodology.

3.5 Issues Not Captured in the WORLD Model

The WORLD Model reflects an “annual average” analysis of the market for the various cases as defined. It does not model short periods of transition such as seasonal demand and supply changes, refinery turnarounds, or inventory builds or draws). The model results are based on a balanced assessment of global supply and demand, including assessing required refinery capacity changes to meet increased demand.

The “balancing” aspect of the model—while providing a consistent and deep analysis of each of the cases evaluated—can tend to understate the potential impact of the rapid increase in tight oil and oil sand supply on the North American market for several reasons:

- The model has certainty of policy—for example, a case assuming “no crude exports allowed” has complete clarity. The model will take action to invest in increased domestic

refinery capacity since lack of crude export ability will force higher domestic runs. In reality, the lack of a definite yes or no on allowing exports would likely create hesitation on the part of refiners for major investments, as well as hesitation on producers and midstream players on adding export facilities. This would likely lead to deeper and longer discounts for domestic crude prices than reflected in the balanced model results.

- Without allowing crude oil exports, the seasonality of the refining business can have a market effect that could be greater than shown in average model runs. While demand variation can be managed through more or fewer product exports, the required annual spring and fall of maintenance work periods for refineries is likely to become more challenging to manage, as could meeting tighter summer constraints on gasoline quality. Historically, these periods have resulted in reduced refinery runs of up to a million barrels per day or more for several months. Annual refinery runs have recently averaged 15 MMBPD, but there have been periods when throughputs have been as low as 14 MMBPD or above 16 MMBPD. These variations have normally been managed by a combination of reducing imported supply during turnaround periods and holding more inventory in refinery tanks, and then gradually drawing inventory and restoring imports after the turnaround.
- As increased domestic and Canadian crude supply continues to reduce imports, a much higher use of North American crude would be expected, with U.S. crude production as a share of U.S. liquids consumption increasing from 40 percent in 2013 to between 62.8 percent and 64.4 percent averaged over 2015–2035 according to model results. Consequently, the ability to use imports to manage refinery turnaround demand changes would become less feasible as their volumes decline, and refiners would need to either store domestic crude or reduce domestic purchases. With storage capacity for domestic crude essentially limited to Cushing, the impact of reduced refinery demands during turnarounds may be very bearish on the market without the ability to export crude. Crude storage ability on the Gulf Coast is limited as major distribution hubs are becoming more congested handling and distributing the additional tight oil and ultimately heavy Canadian. The resulting buildups in Cushing could result in downward spikes in WTI potentially similar to those seen in 2011 and 2012.

Such issues are not captured in the WORLD Model in that it is an annual model that balances supply and demand for 365 days at a time rather than seasonally or monthly. Therefore differences in supply or demand that occur seasonally are not separately represented. This means the model will not forecast potential price declines for domestic crudes caused by greater use of North American crudes and less flexibility to modulate crude imports to manage refinery turnarounds during short periods.

The WORLD Model is also a “perfect foresight” model in that volumes, prices, and policies are assumed to be known to all market participants and there is no uncertainty that might delay investments or changes in behavior. This means that the model can optimize investments and eliminate price disequilibria faster than would occur in the real world where uncertainty about U.S. production growth, pipeline construction, market demand, and government policies can lead to delays.

4 Energy Impacts of Crude Exports

This study found that lifting the U.S. crude export restrictions alters the crude and petroleum product supply-demand balance in a number of ways. Lifting the restrictions:

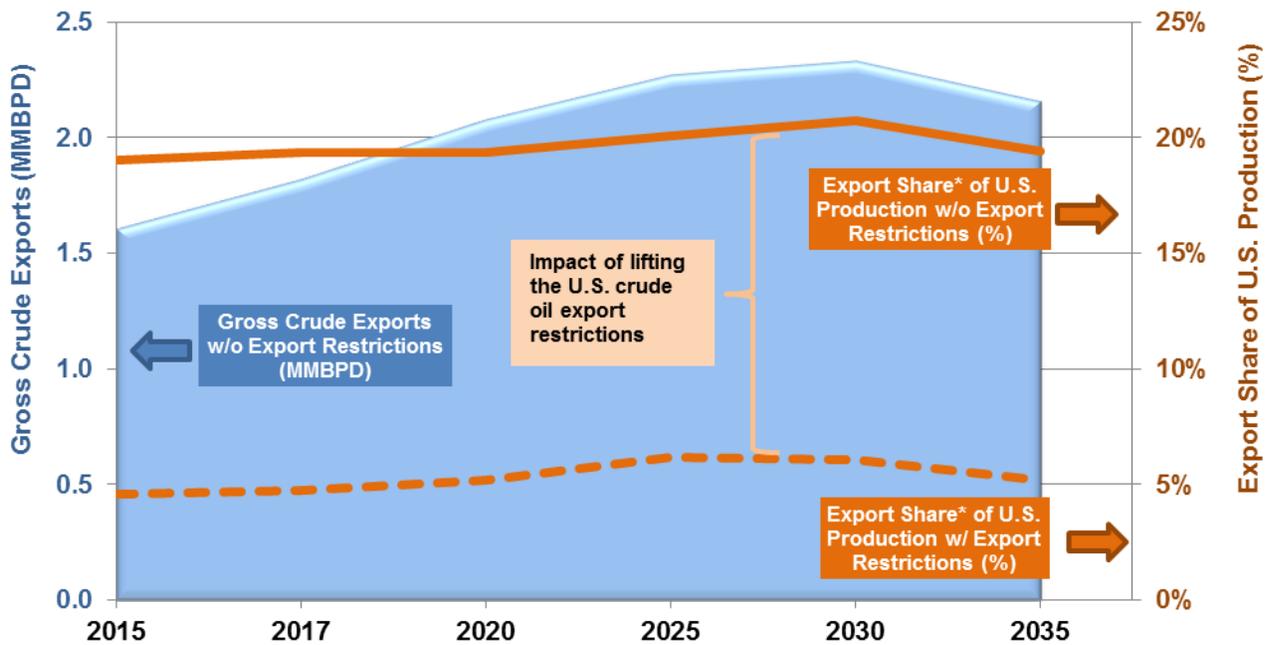
- Increases U.S. and Canadian crude oil production
- Increases domestic crude oil prices, while decreasing global crude and petroleum product prices
- Narrows the current differential between U.S. and international crude oil prices
- Reduces U.S. refinery margins
- Alters crude import/export patterns

While robust shale resources mean U.S. crude oil production will continue growing in all cases, lifting the export restrictions leads to incremental production as producers respond to a more attractive pricing environment relative to the expected environment where domestic crudes are bottlenecked by export restrictions. Most of U.S. production growth will be light sweet crude from tight oil formations whereas Canadian production growth will be concentrated on oil sands.

This study found that the U.S. oil resource base could economically accommodate gross crude oil exports of roughly 20 percent of U.S. total crude oil production on average between 2015 and 2035, as shown below. This equates to an average of 2.1 MMBPD in gross crude exports over the period if export restrictions were to be lifted, up from 580,000 BPD (averaging 5.5 percent of U.S. oil production) if export restrictions remain in place.⁴²

⁴² The United States currently allows export of domestic crude oil in a few cases, such as the following: 1) from oil produced in Alaska's North Slope and Cook Inlet, 2) up to 25,000 BPD in production from California's heavy oil fields, and 3) crude exports to Canada if the crude supplies remain in Canada or are re-exported to the United States. Other options are also permitted (e.g., exports of oil in exchange for strategic petroleum reserve volume) under defined conditions.

Exhibit 4-1: Gross Crude Exports and Share of U.S. Crude Production



Source: ICF International and EnSys Energy

Note: Based on the Low-Differential Scenario. * Refers to gross crude exports share of total U.S. production

Depending on the pace of infrastructure development to align with crude production growth, the pricing of different North American crudes could vary, having implications on refinery operations and export economics. The petroleum industry has announced investments to enhance pipeline and rail capacity to bring bottlenecked crudes to markets, as well as investments to handle lighter crudes and condensates. There remain significant uncertainties in terms of whether and when these investments will be realized.

In the short run, if exports are not allowed, refineries could face operational issues in handling lighter crude slates because many U.S. refineries have optimized their configurations to run heavier crudes. Petroleum product net imports will continue the current declining trend with increasing gross product exports and declining gross product imports. Lifting the crude export restrictions has the effect of substituting some of these product exports (particularly naphthas) with crude exports, as this could be a more economic choice than investing in refinery infrastructure to process lighter crudes.

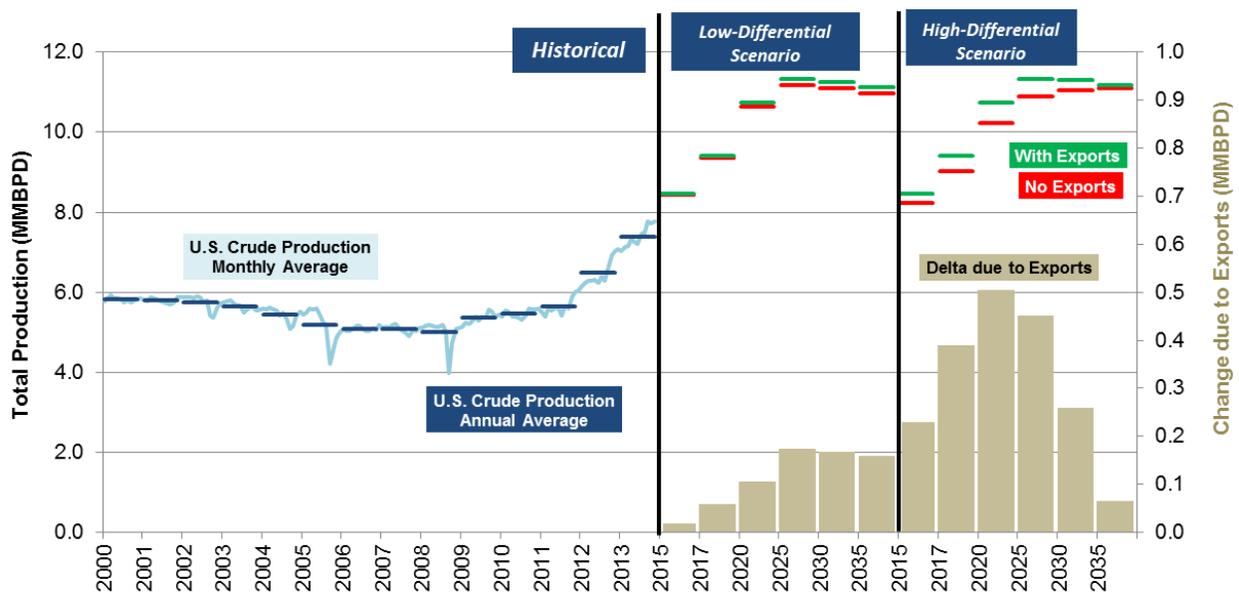
4.1 Volume Impacts

Crude and Condensate Production

Allowing exports improves crude oil economics for producers, as buyers will no longer require a discount for domestic crudes to account for logistical bottlenecks and refinery processing issues. As shown in Exhibit 4-2, U.S. oil production is projected to increase to an average of 10.7 MMBPD from 2015 to 2035 when crude exports are allowed. Depending on the scenario,

this production level is 130,000–300,000 BPD higher on average than when crude exports are restricted. With current export restrictions, production only averages 10.6 MMBPD over the same period in the Low-Differential Scenario because domestic crude continues to suffer from the logistical bottlenecks. In the High-Differential No Exports Case, where WTI maintains the current price discount to Brent for a longer period of time, producers receive even lower values for their crudes than in the Low-Differential No Exports Case, with production averaging 10.4 MMBPD over the forecast period. Allowing crude oil exports leads to an increase in U.S. oil production of 110,000 to 500,000 barrels per day by 2020. This additional crude production would mean \$15.2–\$70.2 billion in additional investment between 2015 and 2020, depending on scenario.

Exhibit 4-2: U.S. Crude Production Impact



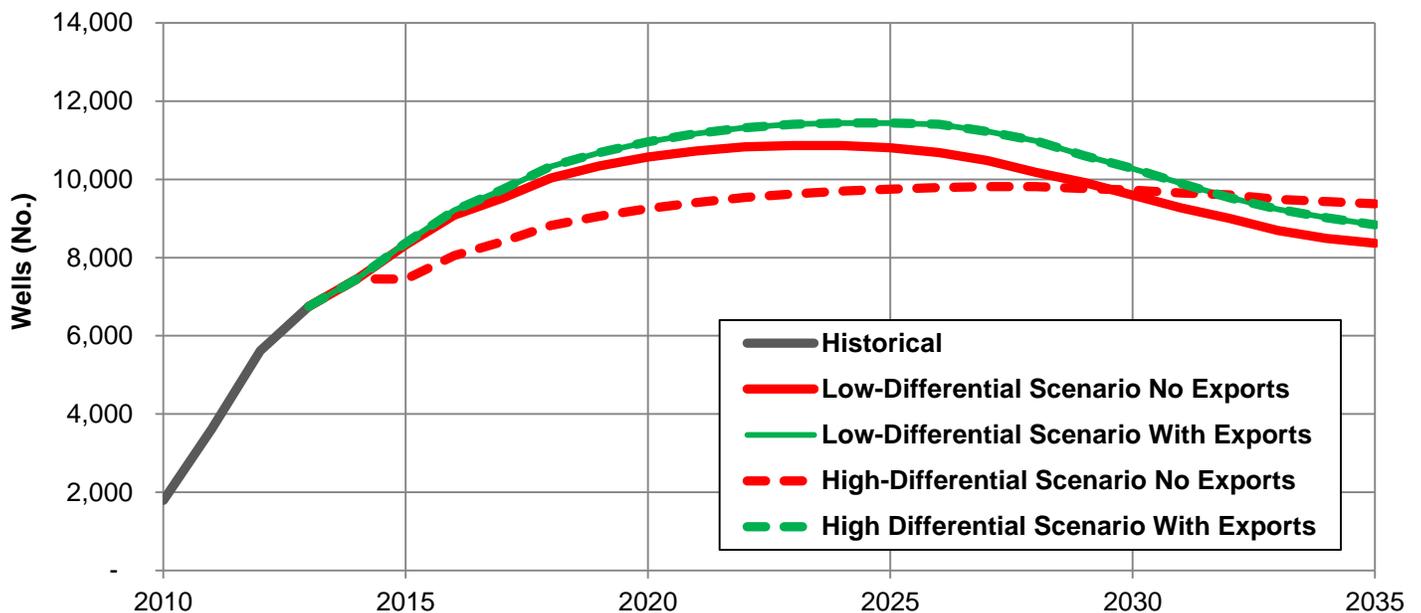
Sources: EIA – historical; EnSys WORLD Model and ICF analysis – projections

Tight oil well drilling increases by an average of 500–1,000 annual wells between 2015 and 2035 if exports are allowed. Major tight oil production will be seen from plays such as the Bakken Shale in the Williston Basin (North Dakota), the Eagle Ford Shale in South Texas, the Niobrara in the Denver Basin (Colorado), and various plays in the Permian Basin of West Texas and southeastern New Mexico, which has become a major component of U.S. oil production.

The projection of tight oil wells drilled each year are made separately for each play based on a marginal economic analysis using forecasted light crude prices coming from the WORLD Model. The economics for each play are based on the average capital and operating costs per well in each play and the projected average well recovery—barrels of crude oil and million cubic feet (MMcf) of gas produced over the lives of new wells drilled in each year. In the forecasting model, well productivity starts out at the historical average estimated for each play and then is adjusted downward each year to account for resource depletion such that the average productivity, if all wells were to be drilled, equals that expected average productivity estimated

by ICF map-based resource base analysis. The effect of new technologies is modeled as an upward adjustment to well recoveries. The number of wells drilled each year in each play is a function of how the value of revenues earned by each well compare to capital and operating cost including a 10 percent real rate of return. Drilling activity grows when revenues far exceed costs, are flat as revenues and cost are similar, and decline when revenues fall below the cost target. As shown in Exhibit 4-3, when exports are allowed, the U.S. can sustain growing levels of tight oil drilling through about 2025, after which the best portions of some plays are fully developed and drilling levels decline. When U.S. crude exports are restricted the resulting lower domestic prices for crude oil slow drilling levels, which results in different patterns of drilling in the forecast period.

Exhibit 4-3: U.S. Tight Oil Wells



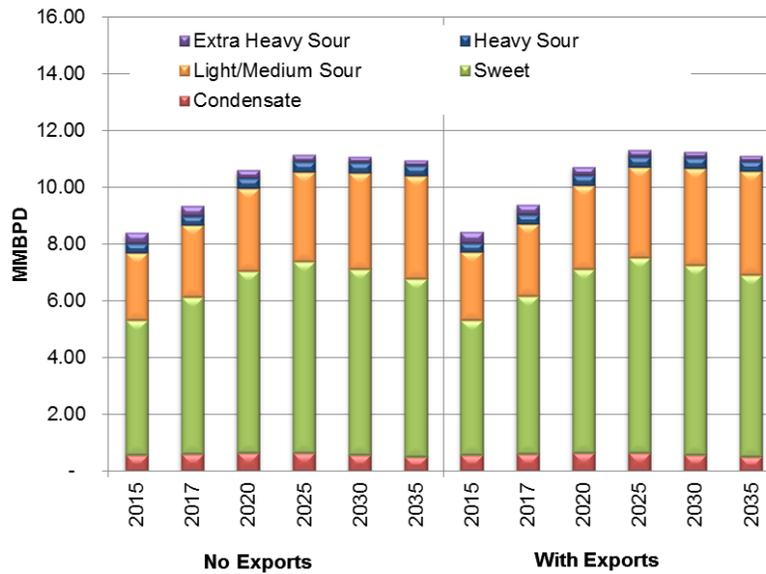
Sources: ICF analysis

In 2010, tight oil accounted for six percent of U.S. production.⁴³ By 2013, the percentage increased to 24 percent. Virtually all tight oil production volumes are light sweet, effectively increasing the API gravity of domestically produced crude as a whole. Exhibit 4-4 shows the projected makeup of U.S. produced crude 2015 to 2035. When exports are allowed, sweet crude production will grow to an estimated 6.5 MMBPD by 2020 and average 6.3 MMBPD over the study period, accounting for roughly 59 percent of total U.S. crude production. Light and medium sour crude will account for roughly 30 percent of production while condensates will make up about five percent. Growth in medium U.S. crudes will come mostly from the deep-water Gulf of Mexico. Light crude production is slightly stronger in the exports case due to the

⁴³ Based on ICF analysis. Other studies may show different results.

incremental tight oil well drilling, but the breakout of crude production is very similar with or without exports. This abundance of domestic light sweet crudes will have major implications for refinery operations and midstream investment considerations.

Exhibit 4-4: U.S. Crude Production by Type



Sources: EnSys WORLD Model

If exports are allowed, the resulting increase in U.S. and Canadian crude production will feed into global crude supply growth. ICF projects global crude and condensate production to reach 94.3 MMBPD in 2035 with exports, up from 94.1 MMBPD in 2035 without U.S. crude exports. This supply growth will exert modest downward pressure on global crude prices as will be further discussed below. Of course there are uncertainties underlying this projection such as OPEC response to growing U.S. and Canadian supply and other uncertainties in oil markets. However, the additional North American supplies will make it more difficult for OPEC to maintain prices since its market share of world crude demand will be reduced.

Along with crude production growth due to U.S. crude exports, global liquids production rises to a 2015–2035 average of 103.5 MMBPD. If U.S. export restrictions remain, global liquids production is slightly affected, reaching 103.4 MMBPD.

Refinery Changes

U.S. refiners have historically invested in complex units to process heavier crude slates. With the tight oil revolution, however, refiners and midstream companies have announced investments to better process lighter oils to take advantage of the price depression in U.S. crude prices (relative to global oil prices). Exhibit 4-5 outlines these investments. Most of these investments take advantage of the robust light oil and condensate production in the Eagle Ford and the Utica shales.

Exhibit 4-5: U.S. Announced Refinery Investments to Accommodate Light Crude and Condensate

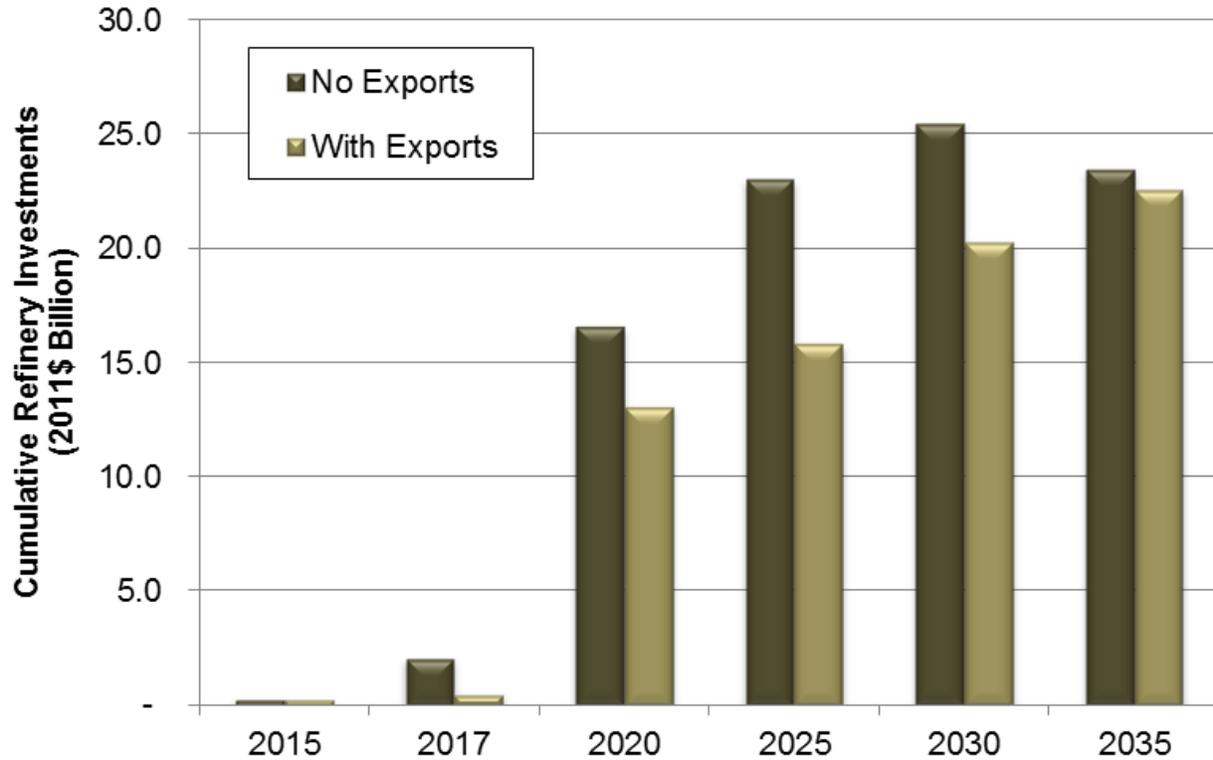
Company	Location	Capacity (TBD)	Cost	Investment Type
Alon	Big Spring	5	Unknown	Refinery expansion
American Energy Holdings	Devils Lake, ND	20	\$250 million	New refinery
Castleton Commodities Intl	Corpus Christi, TX	100	Unknown	Condensate splitter
Dakota Oil Processing	Trenton, ND	20	\$200 million	New refinery
HollyFrontier	Woods Cross, UT	14	\$300 million	Refinery expansion
Husky	Lima, OH	40	\$300 million	Increase heavy crude capacity
Kinder Morgan	Galena Park, TX	100	\$360 million	Condensate splitter
Magellan Partners	Corpus Christi, TX	Unknown	Unknown	Condensate splitter
Marathon	Canton, OH	25	\$250 million for the Canton, OH and Catlettsburg, KY facilities	Condensate splitter
Marathon	Catlettsburg, KY	35		Condensate splitter
Marathon	Robinson, IL	60	\$160 million	Increase light crude capacity
Martin Midstream	Corpus Christi, TX	50-100	Unknown	Condensate splitter
MDU/CLMT Dakota Prairie	Dickinson, ND	20	\$300 million	New refinery
NCRA	McPherson, KS	15	\$327 million	Refinery expansion
Tesoro	Salt Lake City, UT	4	Unknown	Refinery expansion
Three Affiliated Tribes	Dickinson, ND	20	\$450 million	New refinery
Trafigura	Corpus Christi, TX	50	Unknown	Condensate splitter
Valero	Corpus Christi, TX	70	\$350 million	Crude topping unit
Valero	Houston, TX	90	\$400 million	Crude topping unit
Valero	Port Arthur, TX	15	Unknown	Increase light crude capacity
Valero	McKee, TX	25	Unknown	Refinery expansion
Western	El Paso, TX	25	Unknown	Refinery expansion

Source: Compiled from various public sources by ICF International

Note: Due to limitations in other process units, total crude input capacity will not necessarily increase by the same amounts as the project capacities shown in this exhibit. The capacity for projects with announced capacities totals between 803,000 to 853,000 barrels per day.

Exhibit 4-6 shows ICF's forecast of U.S. refinery investments over and above firm projects, which include expansions and modifications to accommodate lighter oils. These facilities are needed to accommodate future crude supply and demand conditions with or without exports. If exports are not allowed, refinery investments ramp up in the earlier years. A key driver is the need to increase light oil processing capacity to handle growing production of U.S. light crude oils that cannot be exported. When exports are allowed, the investments required are lowered by up to \$5–\$7 billion on a cumulative basis; this is because part of the incremental light crude supplies can be exported, reducing the need to revamp refineries to deal with them.⁴⁴

⁴⁴ All projected prices for 2015-2035 in this report are in 2011 dollars, unless otherwise specified.

Exhibit 4-6: U.S. Refinery Cumulative Investments over Firm Projects


Sources: EnSys WORLD Model

The crude oil slate refers to the proportion of oil that distills/condenses within a certain range. The WORLD Model found that without crude oil exports, the average API gravity would increase (i.e., refineries would process lighter oils than when crude exports are allowed), as shown in the exhibit below. This would require more investments to accommodate processing of lighter oils.

Exhibit 4-7: API Gravity by PADD

PADD	With Exports						Without Exports					
	2015	2017	2020	2025	2030	2035	2015	2017	2020	2025	2030	2035
PADD 1	34.50	34.93	36.13	34.48	35.90	36.62	33.59	37.81	34.82	38.47	37.95	39.32
PADD 2	32.53	32.59	32.88	32.11	32.42	32.53	32.67	32.82	33.05	32.50	32.45	32.39
PADD 3	31.75	31.60	32.49	32.60	31.68	31.19	33.31	33.35	34.74	34.12	33.15	32.45
PADD 4	30.95	31.26	34.26	34.03	33.86	34.05	30.95	31.27	34.45	34.70	34.05	34.05
PADD 5	27.96	28.58	29.00	29.01	29.45	29.22	28.43	29.67	29.68	29.37	29.90	29.87
U.S.	31.49	31.58	32.35	32.12	31.88	31.66	32.30	32.85	33.55	33.31	32.84	32.53

Source: EnSys WORLD Model

With the increasing production of domestic light crude, ICF expects the crude slate coming into U.S. refineries to become lighter. From 2010 to 2012, average API gravity of crude input into

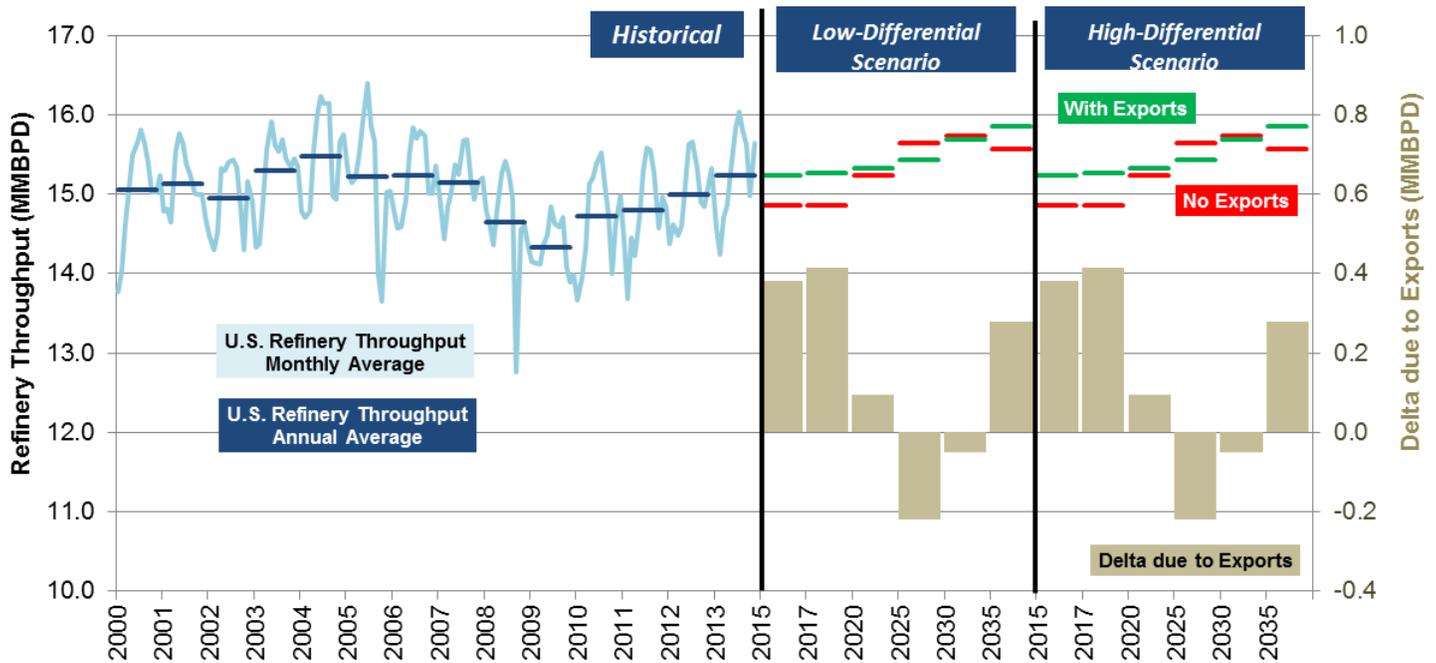
U.S. refineries increased from 30.71 to 31.00 degrees API.⁴⁵ If exports are allowed, the average API gravity of crude inputs is expected to rise to a 2015–2035 average of 31.91 degrees, down from 32.97 degrees API when exports are not allowed. This seemingly small difference in the long-term national averages masks the fact that the bulk of the impact is likely to be in one U.S. refining region, namely the Gulf Coast (PADD 3). Within that region, the impacts are projected to be sharper, especially short term. Versus an average crude gravity of 31.0 in 2012 and 30.0 in 2013, PADD 3 crude slate is projected to lighten rapidly to 33.33 degrees API in 2015 to 2017 if crude exports are not allowed. As previously stated, allowing exports enables the lightest crudes to be exported (partially offsetting imports of heavier crudes). As a result, PADD 3 crude slate in the 2015/2017 period rises only to around 31.68 degrees API. This is a more manageable rise that (a) leads to less need to invest in distillation capacity purely to handle the light crudes and (b) reduces the risk of the refineries in the region having to cut throughputs in the short term because the light crudes constrain their processing capacity.

On average over the forecast period, exports increase throughput by better matching crude types to the appropriate refinery.

A question being posed by many analysts is how much light crude U.S. refineries can absorb without significant modifications. Refineries typically have a certain degree of feedstock flexibility (i.e., the ability to process a crude slate lighter or heavier than the usual diet), though this ability varies by refinery. In the short term, and depending on refiners' cumulative flexibility (there are no data available), not allowing crude exports could result in constrained throughputs as U.S. refiners struggle to digest light crudes and condensates. Allowing crude exports would relieve this problem, enabling refineries to better optimize their crude streams, and thereby could increase refinery runs (or avoid reductions) in the short term, as shown in Exhibit 4-8.

⁴⁵ U.S. Energy Information Administration. "U.S. API Gravity (Weighted Average) of Crude Oil Input to Refineries". U.S. EIA, accessed 3/7/2014: Washington, DC. Available at: <http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=p&s=mcrapus2&f=a>

Exhibit 4-8: U.S. Refinery Throughput Impacts



Sources: EIA – historical; EnSys WORLD Model and ICF analysis – projections

The modeling analysis projected a small near-term increase in refinery throughputs when export restrictions are lifted. However, all scenarios with and without exports, show a general long-term upward trend in U.S. refinery throughput. U.S. refineries are projected to enjoy competitive advantages due to low-cost domestic crude oil and natural gas and higher refinery complexity, compared to those in other parts of the world. Historically, U.S. refinery throughput rose from an annual average of 15.1 MMBPD in 2000 to 15.2 MMBPD in 2013. Refinery throughput is expected to increase to a 2015–2035 average of 15.5 MMBPD when the crude export restrictions are lifted, which is 100,000 BPD or 0.6 percent higher than would exist if the restrictions were kept in place.

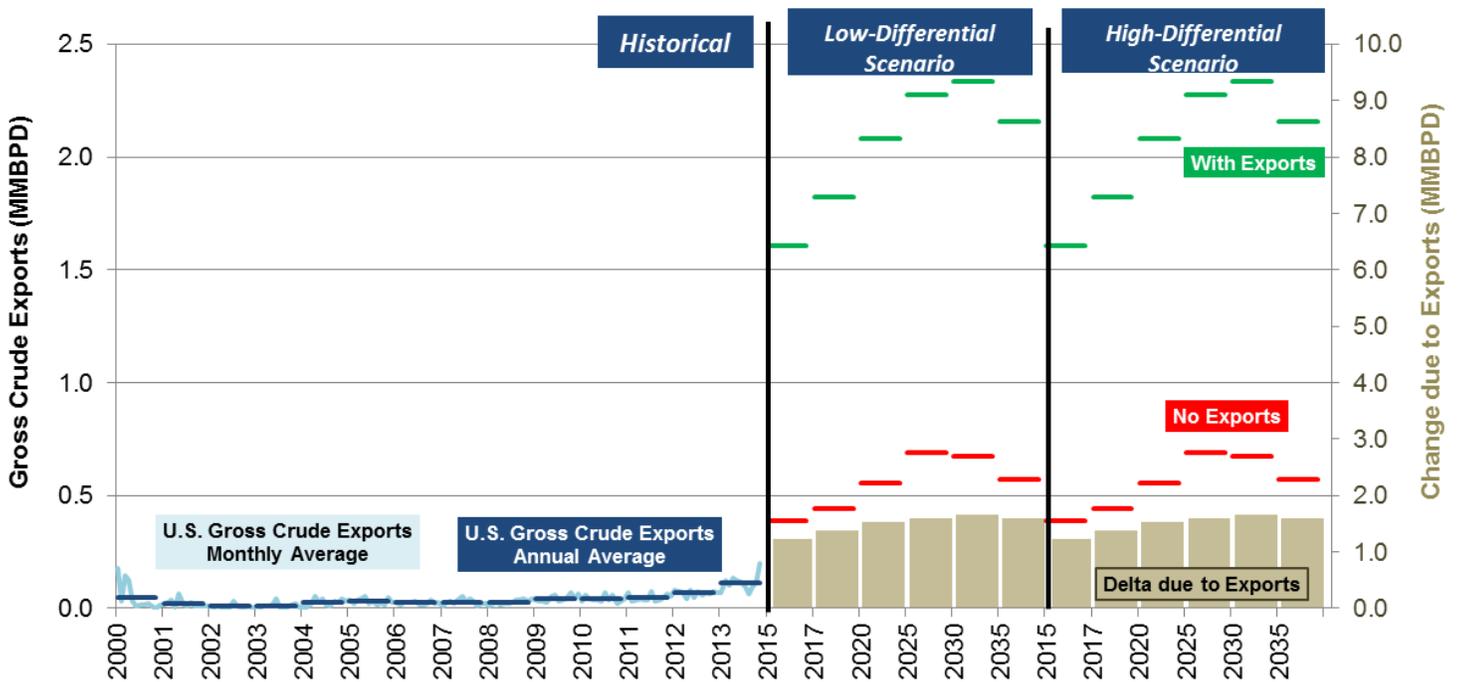
It should be noted that the upward impact on refinery runs of allowing exports that is evident in the early years, is expected to diminish relative to a No Exports outlook, as refineries gradually adapt operations to the generally lighter domestic crude in the long term. Allowing exports could have small downward impacts on refinery throughputs in later years. In general and with all other factors being equal, higher refinery margins tend to lead to increased throughput. With the cost of domestic crude slightly higher with exports and refined products slightly lower U.S. refinery margins and throughput could be slightly lower in some years. However, on average over the forecast period, exports increase throughput by better matching crude types to the appropriate refinery.

Crude Trade Trends

If U.S. crude export restrictions are lifted, gross crude exports are projected to increase fairly rapidly, reaching approximately 1.8 MMBPD in 2017. Over the study period, lifting the exports

restrictions results in the United States exporting a 2015–2035 average of 2.1 MMBPD, which is an average of 1.5 MMBPD more exports than in cases with continued export restrictions. Note that crude exports can increase to Canada and from Alaska in the export-restricted cases. Historically, the United States exported 50,000 BPD of crude in 2000 and up to 110,000 BPD by 2013.

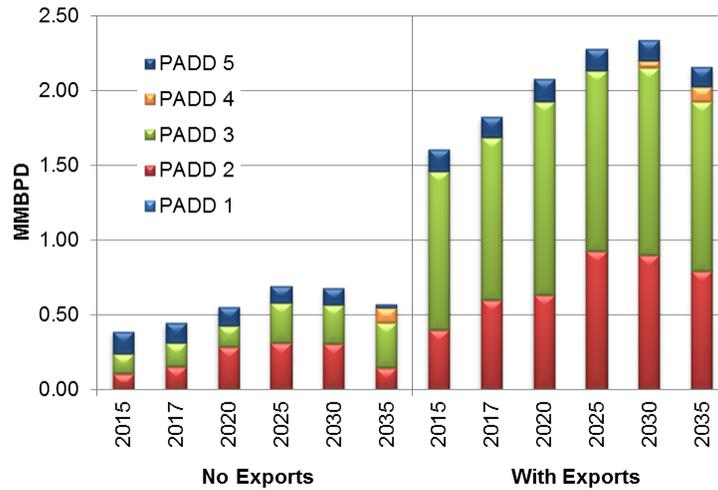
Exhibit 4-9: U.S. Gross Crude Exports Impacts



Sources: EIA – historical; EnSys WORLD Model and ICF analysis – projections

Between 80 and 92 percent of crude exports are projected to originate from PADD 2 (Midwest) and PADD 3 (Gulf Coast). In the No Exports outlook, crude exports from PADD 2 and PADD 3 origins each reach a 2015–2035 average of 0.23 MMBPD. In the With Exports outlook, crude exports originating in PADD 2 reach 0.75 MMBPD while those from PADD 3 production increase to 1.19 MMBPD averaged over the study period. This is consistent with the current U.S. production growth trend particularly in the Bakken and Eagle Ford regions. In addition there is a small volume of Alaskan crude production projected to be exported. This accounts for the 0.1–0.14 MMBPD of crude exports from PADD 5 (West Coast) averaged over 2015–2035. Alaskan North Slope crude is currently authorized for exports under current crude oil export policy and ICF expects producers to take advantage of this allowance in the No Exports Case.

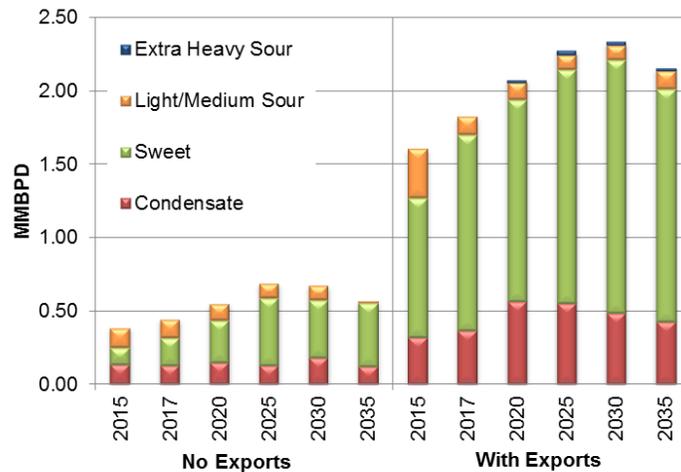
Exhibit 4-10: PADDs of Origin of Exported Crude



Sources: EnSys WORLD Model

As shown in Exhibit 4-11, exported crudes consist mostly of sweet crude and condensates, which account for between 85 percent and 95 percent of crude exports, in addition to a small volume of light, medium and extra heavy sour crude. Since it is the lighter crudes that U.S. refineries are projected to have difficulty processing, it is those crudes that are economically advantageous to export.

Exhibit 4-11: Types of Exported Crudes

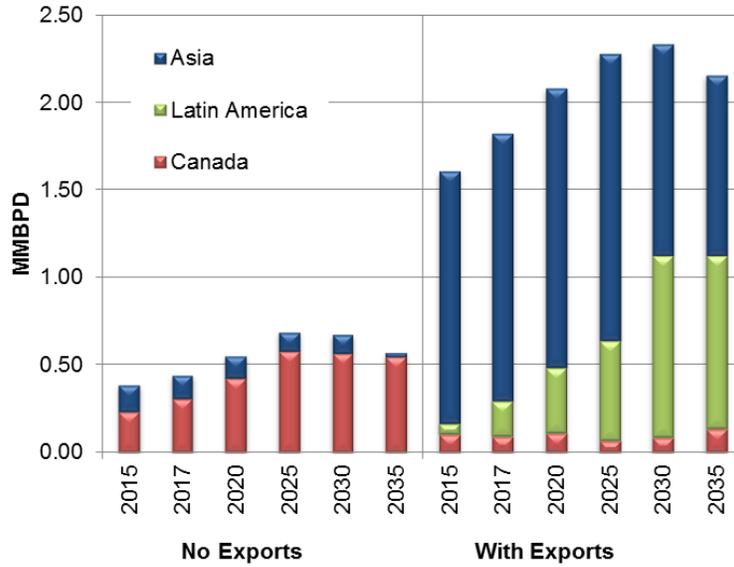


Sources: EnSys WORLD Model

Exhibit 4-12 shows that when export restrictions are lifted, most of the exported volumes go to Asia. A smaller but steadily increasing volume of exports goes to Latin American markets.

Under current regulations exports of crude are only allowed to Canada, therefore exports to Canada make up the majority of exports in the No Exports Case.

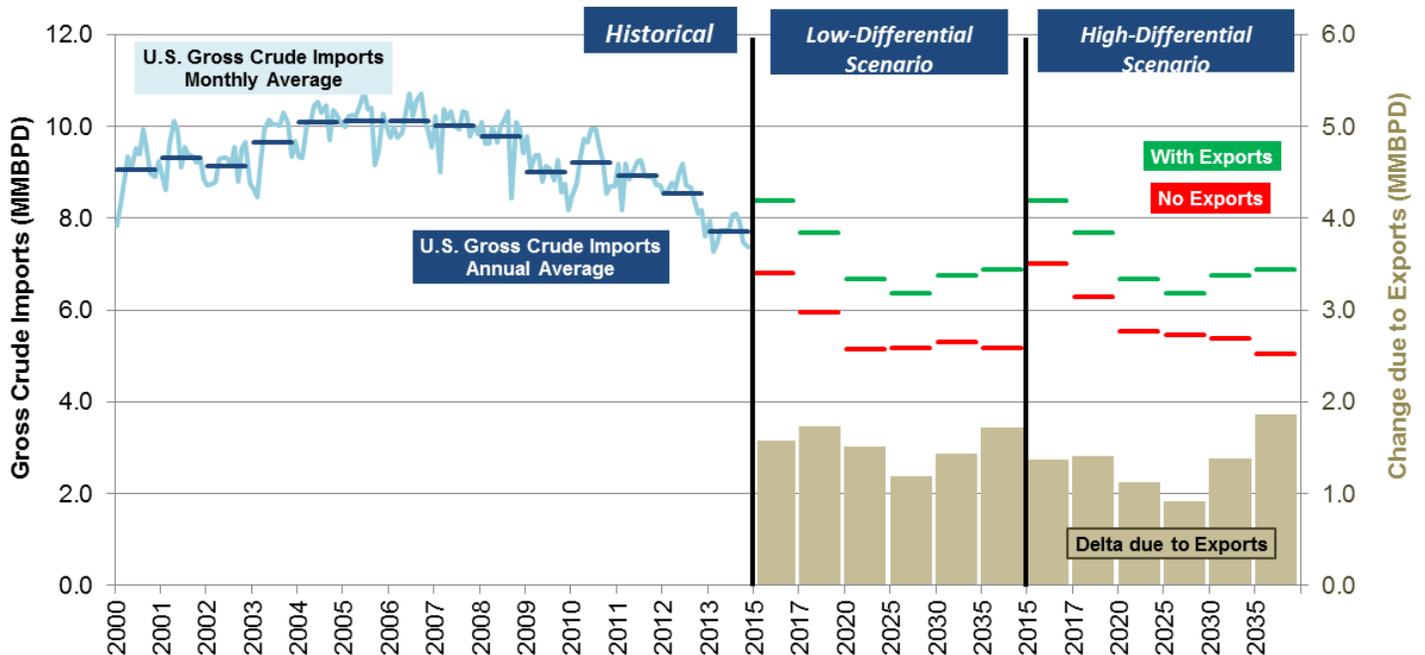
Exhibit 4-12: U.S. Crude Exports by Destination Market



Sources: EnSys WORLD Model

Gross crude imports decline after 2015 in all cases with *and* without crude oil exports, and remain below historical levels. Gross crude imports are expected to decrease from recent levels (8.5 MMBPD in 2012 and 7.7 MMBPD in 2013) to an average of 6.9 MMBPD when crude export restrictions are lifted. On average over the forecast period, this is 1.5–1.7 MMBPD higher than when the export restriction is in place, as the U.S. exchanges exported domestic light crude for imported medium and heavy crudes.

Exhibit 4-13: U.S. Gross Crude Imports Impacts

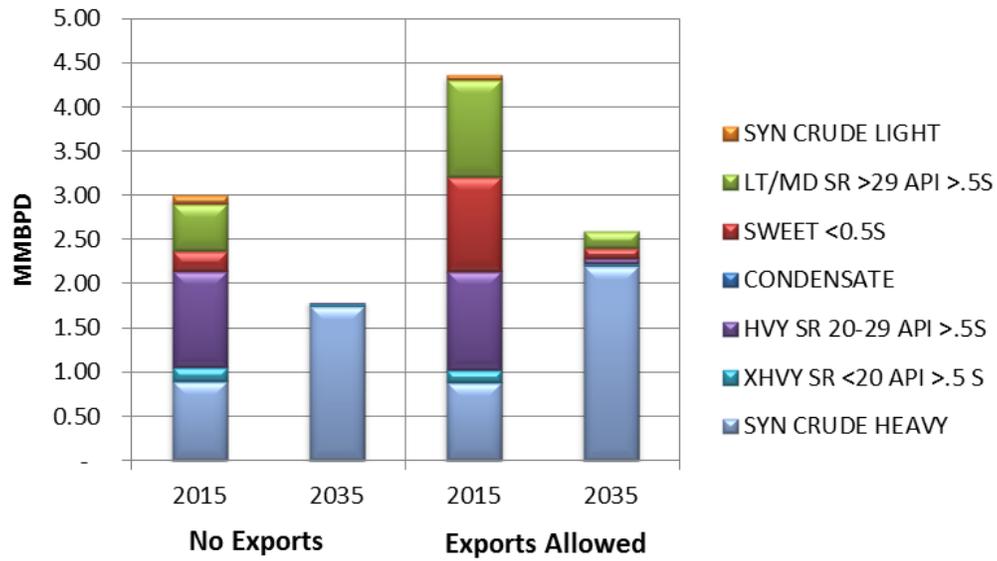


Sources: EIA – historical; EnSys WORLD Model and ICF analysis – projections

Over the past three years, U.S. refineries have imported decreasing volumes of light crude as a share of total crude input. Because the incremental U.S. oil production will be primarily light sweet crude, we expect to see the continuation of this trend of light crude import substitution. Heavier crudes will comprise an increasing share of imports as U.S. tight oil and condensate production backs out light imports.

Exhibit 4-14 shows the forecast crude import trends in the Gulf Coast. Note that the sweet crude volumes shown as remaining in 2015 are entirely medium sweet crude grades. These in turn are projected to gradually disappear over the period. Non-Canadian heavy crude imports are expected to persist in the short term, through 2015, in part because the Keystone XL pipeline was assumed to be approved but not fully on-stream until 2016. Existing contractual arrangements in the Gulf Coast to import heavier crudes from Mexico and the Middle East could also be a factor at least in the shorter term. In the longer term, heavy crudes from western Canada are projected to be primary remaining imports into PADD 3.

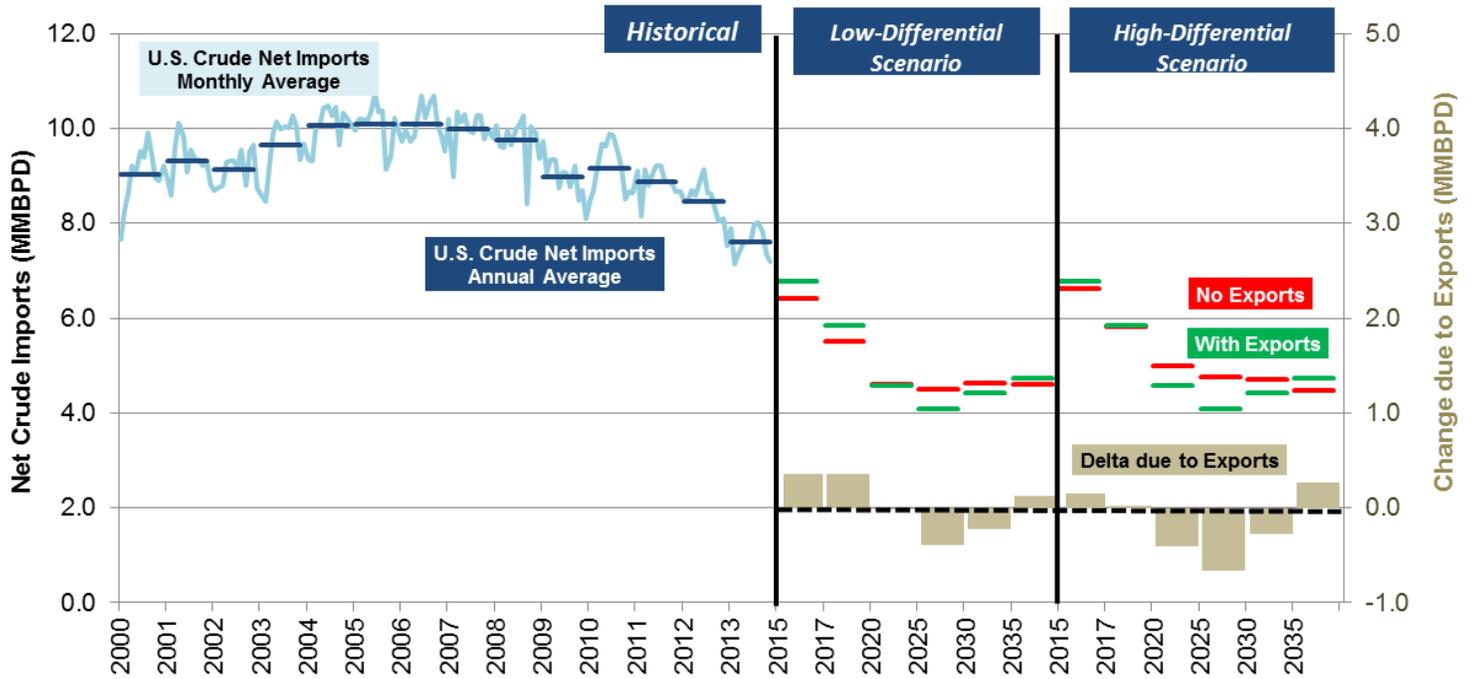
Exhibit 4-14: PADD 3 (Gulf Coast) Crude Imports by Type



Sources: EnSys WORLD Model

Average *net* imports of crude are approximately equal in all cases with and without exports (within 30,000 BPD on average between 2015 and 2035). For historical reference, net crude imports averaged 9.0 MMBPD in 2000 and dropped to 7.6 MMBPD by 2013. Net crude imports are projected to be between 4.5 and 4.8 MMBPD by 2035 in all scenarios.

Exhibit 4-15: Net Crude Imports



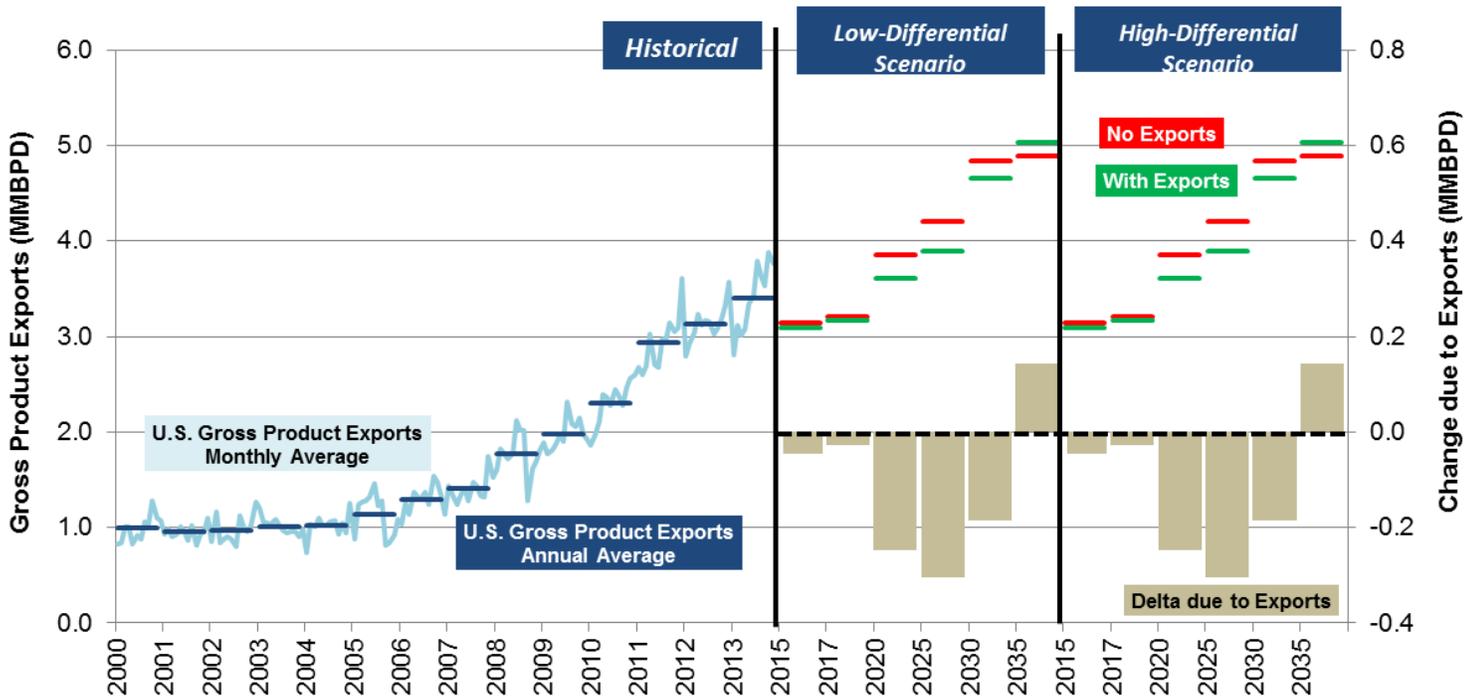
Sources: EIA – historical; EnSys WORLD Model and ICF analysis – projections

Petroleum Product Trade Trends

As shown in Exhibit 4-16, U.S. petroleum product exports increase to an average of 4.1 MMBPD in the With Exports Case over the 2015 to 2035 period, down 130,000 BPD from the No Exports Case. The general upward trend in product exports is partly driven by the slowing liquid fuels demand in the United States (the EIA projects U.S. liquid fuels demand to decline from the peak of 19.8 MMBPD in 2020 to 18.9 MMBPD in 2035).⁴⁶ U.S. petroleum product exports also continue being attractive globally because U.S. refineries are projected to continue to benefit from relatively lower natural gas and crude prices.

⁴⁶ U.S. Energy Information Administration (EIA). “Annual Energy Outlook”. U.S. EIA, April 2013: Washington, D.C. Available at: [http://www.eia.gov/forecasts/aeo/pdf/0383\(2013\).pdf](http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf)

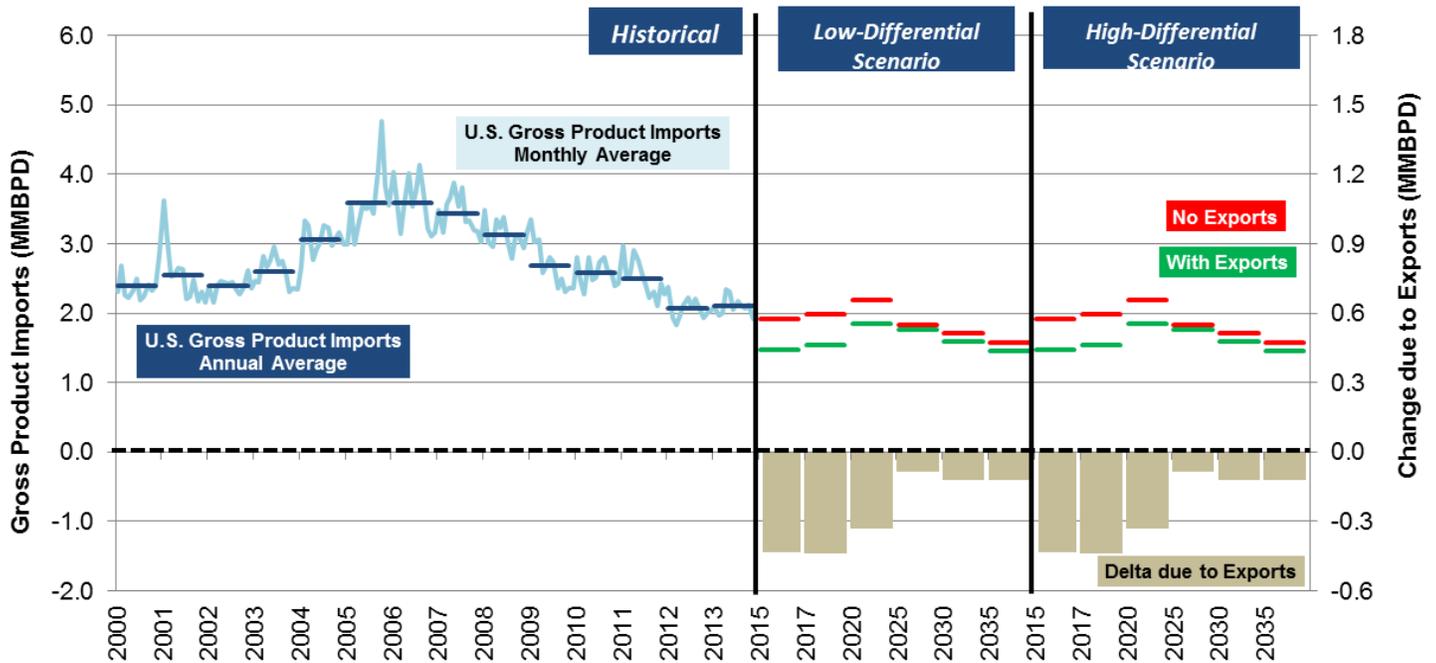
Exhibit 4-16: Gross Product Exports Impacts



Sources: EIA – historical; EnSys WORLD Model and ICF analysis – projections

Exhibit 4-17 shows gross product imports to decline in all cases. Lifting the export restrictions lowers gross product imports by an average of 0.3 MMBPD. The impact of lifting the export restrictions is greater through 2025 than in the later years.

Exhibit 4-17: Gross Product Imports Impacts

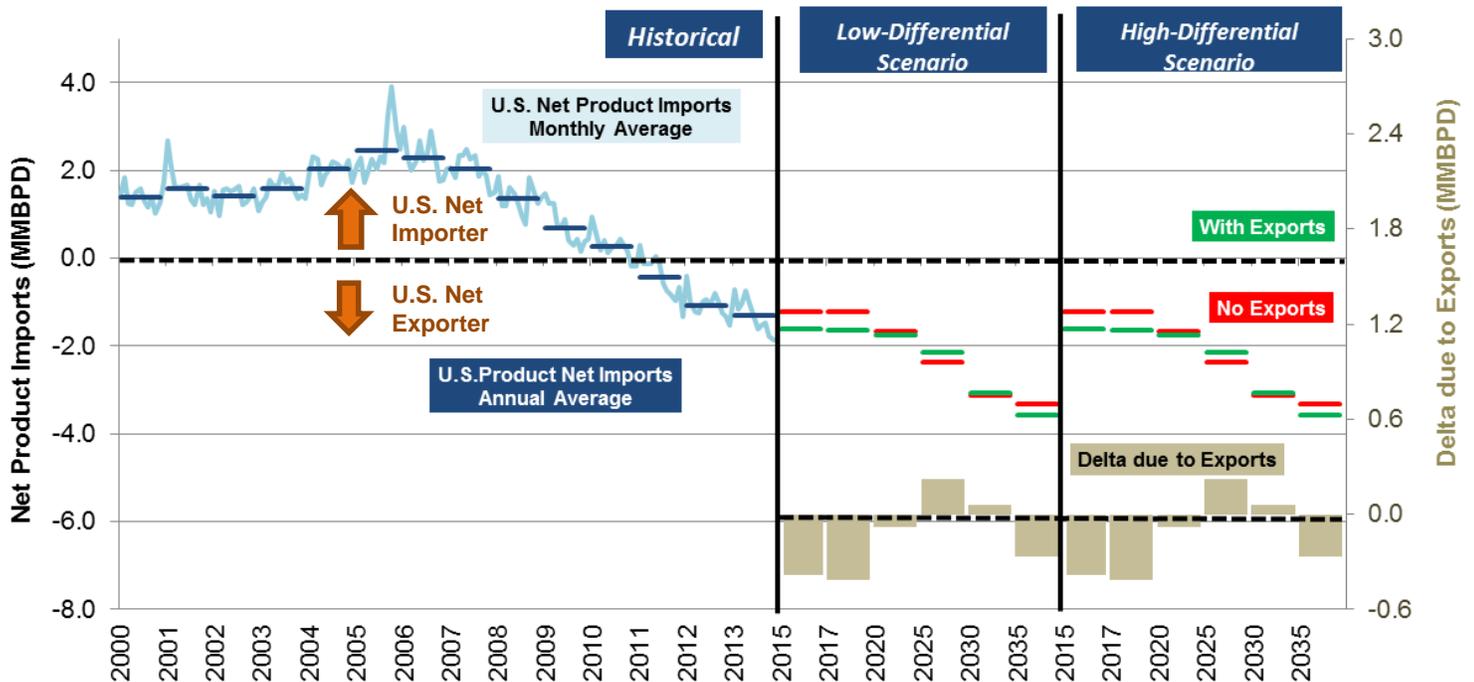


Sources: EIA – historical; EnSys WORLD Model and ICF analysis – projections

As shown in Exhibit 4-18, the combination of higher gross product exports and lower gross product imports results in lower *net* product imports across both the No Exports and With Exports outlooks. The United States has become a net importer of petroleum products since 2011, due to robust global demand for petroleum products (particularly distillate) and access to increasingly abundant domestic crude.⁴⁷ This international trade reversal fundamentally altered the U.S. trade in petroleum products, as the country has been a net importer of petroleum products for several decades, as shown in the exhibit below. Net product exports increased from 1.3 MMBPD in 2013 to 2.4 MMBPD in the Export Case, or 2.3 MMBPD with crude exports restricted. This shows that allowing crude exports actually raises net product exports 100,000 BPD on average over the forecast period. Higher net product exports translate to improvements in the U.S. balance of trade, as will be further discussed in Section 5.

⁴⁷ U.S. Energy Information Administration. "U.S. petroleum product exports exceeded imports in 2011 for first time in over six decades". U.S. EIA, 7 March, 2012: Washington, DC. Available at: <http://www.eia.gov/todayinenergy/detail.cfm?id=5290>

Exhibit 4-18: Net Product Imports Impacts



Sources: EIA – historical; EnSys WORLD Model and ICF analysis – projections

Note: Lower negative values actually denote higher exports and/or lower imports).

4.2 Pricing Impacts

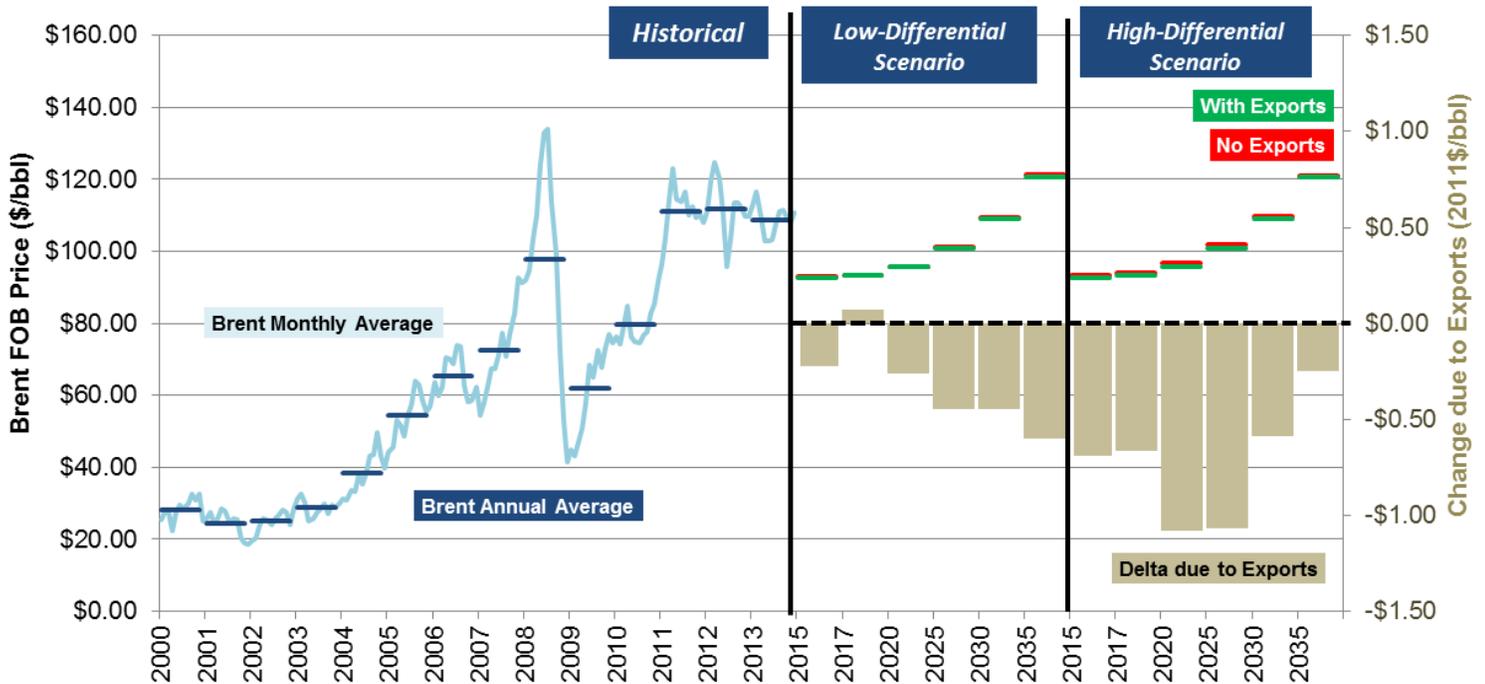
The increase in U.S. crude production accompanied by a relaxation of crude export constraints would tend to increase the overall global supply of crude oil, thus putting downward pressure global oil prices. Although the U.S. is the second largest oil producer in the world and could soon be the largest by 2015, according to the International Energy Agency (IEA)⁴⁸, the price impact of crude exports is determined by the incremental production, rather than total production. For this study, ICF used Brent crude as proxy for the global crude price as affected by forces of global crude supply and demand. The impact of lifting crude exports on Brent prices, as shown in Exhibit 4-19, is relatively small, about \$0.05 to \$0.60/bbl in the Low-Differential Scenario and about \$0.25 to \$1.05/bbl in the High-Differential Scenario.

It should be noted that Brent prices are affected by various factors such as emerging supply sources, OPEC responses to increasing U.S. and Canadian production, and geopolitical events. Changes in any of these factors could mean actual Brent prices would deviate significantly from our forecasts. However, in general, higher global production leads to lower crude prices, all other factors being equal.

⁴⁸ Smith, Grant. "U.S. to be top oil producer by 2015 on shale, IEA says". Bloomberg, 12 November, 2013. Available at: <http://www.bloomberg.com/news/2013-11-12/u-s-nears-energy-independence-by-2035-on-shale-boom-iea-says.html>

Allowing crude exports results in a Brent average price of \$103.85/bbl over the 2015–2035 period, down \$0.35/bbl from the Low-Differential Scenario without exports and down \$0.75/bbl from the High-Differential Scenario without exports.

Exhibit 4-19: Brent Price Impacts

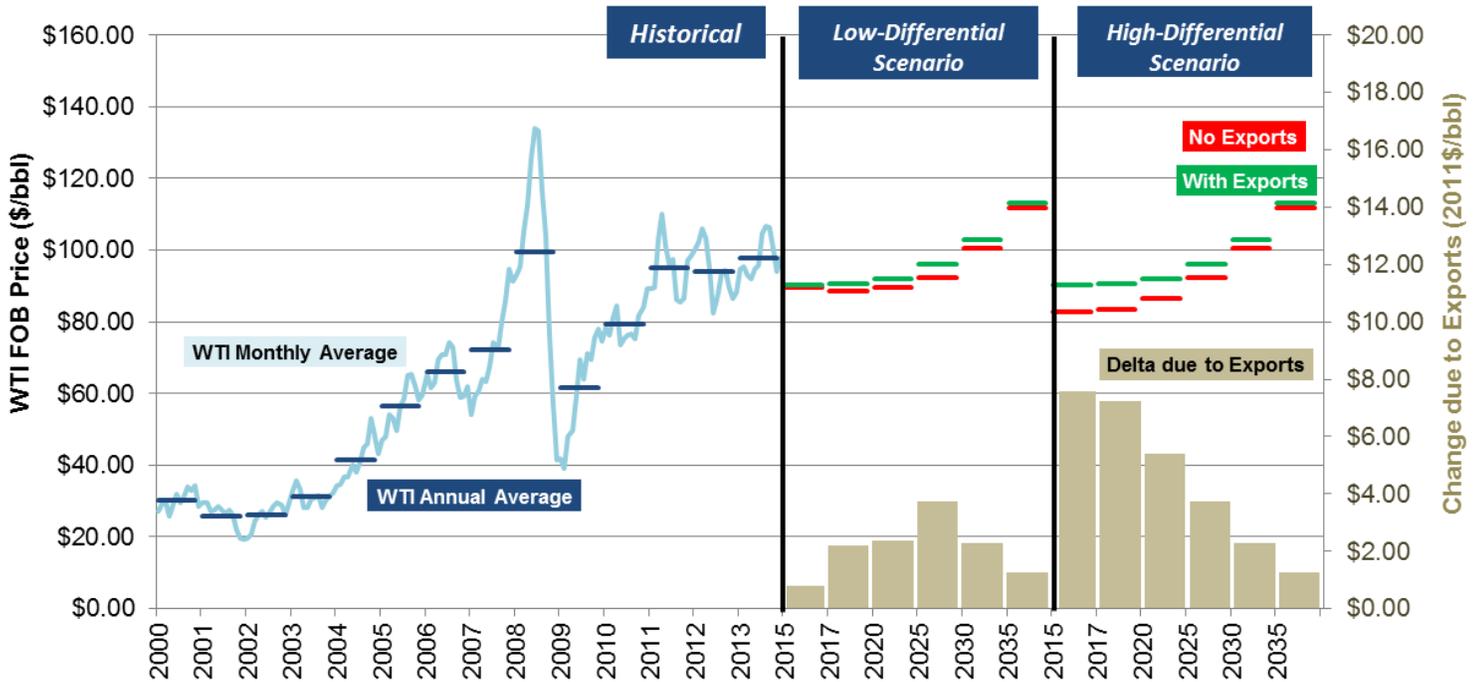


Sources: Bloomberg – historical; EnSys WORLD Model and ICF analysis – projections

Note: Historical data are nominal dollars and the forecasts are in real 2011 dollars.

While global crude prices drop, domestic crude prices gain strength when exports are allowed because lifting the restrictions helps relieve the U.S. crude oversupply situation and allows U.S. crudes to fully compete and achieve pricing in international markets close to those of similar crude types. Exhibit 4-20 shows WTI prices increase to an average of \$98.95/bbl over the 2015–2035 period in the Low-Differential and High-Differential With Exports Cases as opposed to \$96.70/bbl in the Low-Differential No Exports Case and \$94.95/bbl in the High-Differential No Exports Case. The range of increase related to allowing exports is \$2.25 to \$4.00/bbl averaged over 2015 to 2035.

Exhibit 4-20: WTI Price Impacts



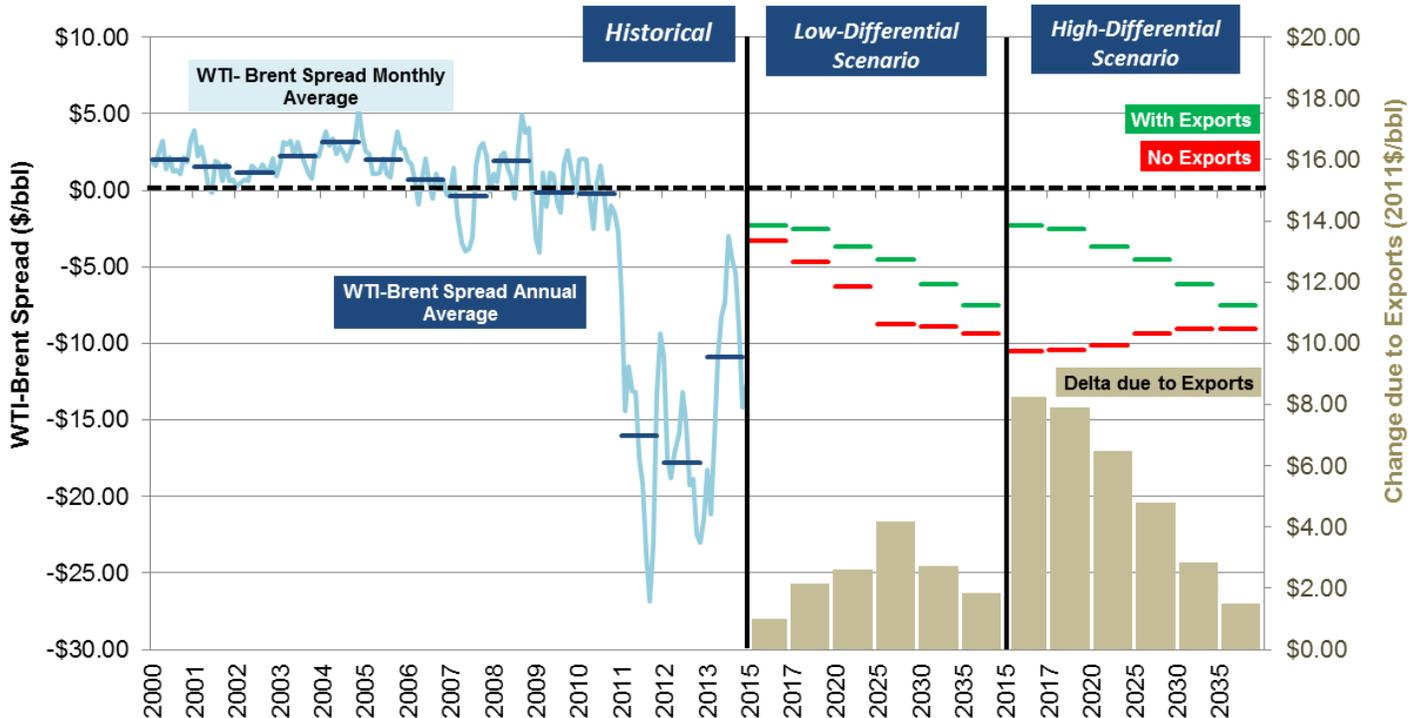
Sources: Bloomberg – historical; EnSys WORLD Model and ICF analysis – projections

Note: Historical data are nominal dollars and the forecasts are in real 2011 dollars.

Going forward, ICF expects WTI prices will not fully recover their historical parity to Brent and could remain discounted relative to Brent, particularly in the near term if refiners are not able to react fast enough to rising light and condensate production. Factors affecting the pace of refinery changes could include delays in environmental permitting of new refinery facilities, persistence of existing contracts for imported crudes, U.S. production rising faster than refiners anticipate, and uncertainties in government policies related to crude exports. These factors could result in a market where steep discounts are required to process a sub-optimum mix of crudes, particularly when exports are not allowed. Exhibit 4-21 shows the WTI-Brent differential widens by up to an average of \$7.50/bbl over the period when U.S. exports are constrained or

up to \$9.60/bbl in the High-Differential Scenario. The average differential is much lower in the Low and High-Differential With Exports Cases, at \$4.85/bbl.

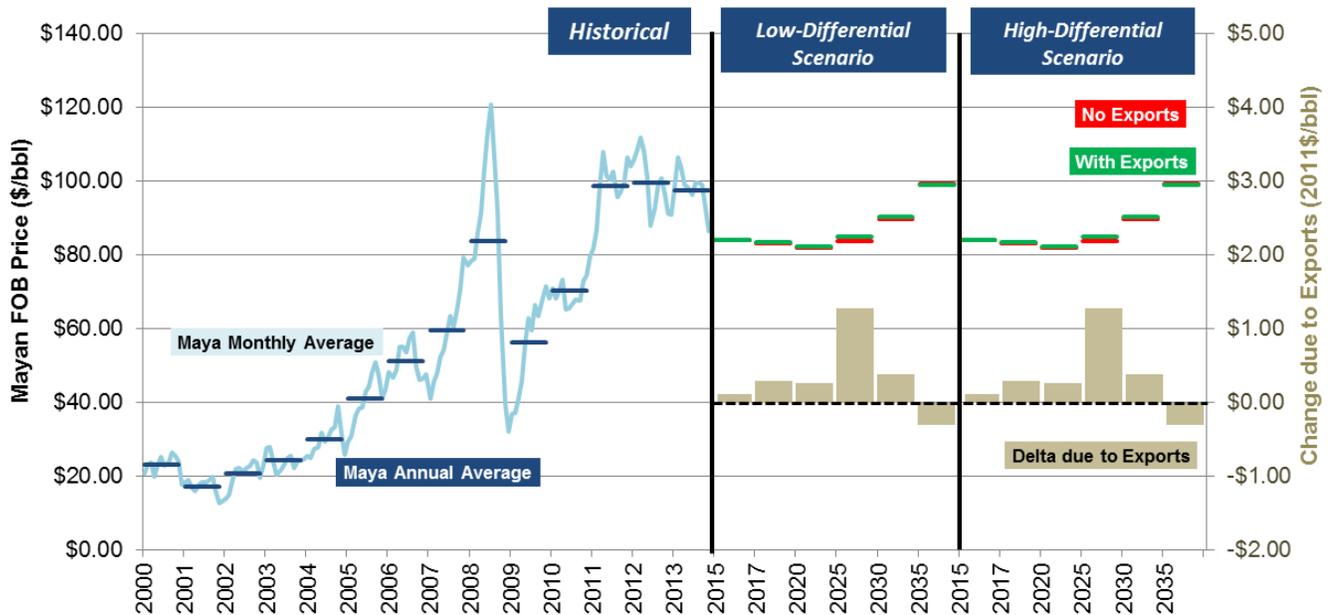
Exhibit 4-21: WTI-Brent Price Differentials Impacts



Sources: Bloomberg – historical; EnSys WORLD Model and ICF analysis – projections

Note: Historical data are nominal dollars and the forecasts are in real 2011 dollars.

The constraints on U.S. crude exports also moderately depress heavy crude prices as the existence of abundant light domestic crude oil that must be processed within the country pushes out imports of heavy oil, whether from Latin America, Canada, or elsewhere. Heavy crude prices affect the economics of “coking refineries” that process vacuum residuum into lighter products. The price of Mexican Mayan, which ICF and EnSys used as the proxy price for heavy crudes, increases to a 2015–2035 average of \$88.05/bbl when exports are allowed, up \$0.35/bbl from when exports are not allowed. These higher prices for heavy crudes reduce margins for coking refineries when exports are allowed. The impact of lifting crude exports restriction on Mayan crude prices is highest in 2025, reflecting the strong U.S. crude exports and production this year.

Exhibit 4-22: Mayan Price Impacts


Sources: Bloomberg – historical; EnSys WORLD Model and ICF analysis – projections

Note: Historical data are nominal dollars and the forecasts are in real 2011 dollars.

4.2.1 Refined Product Pricing Impacts and Consumer Fuel Savings

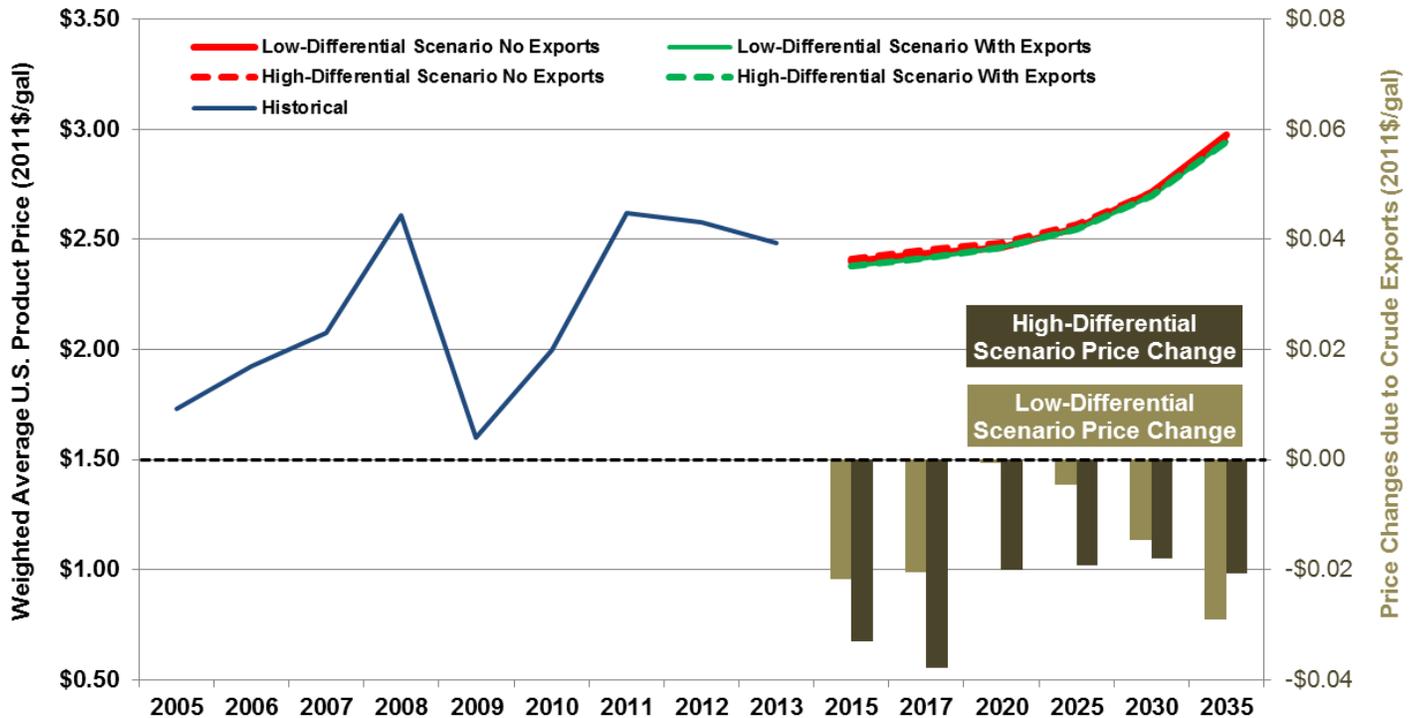
Over the last eight years, the United States has seen a 43 percent increase in average wholesale petroleum product prices, weighted by product type volumes, from \$1.73 per gallon in 2005 to \$2.48 per gallon in 2013. While the recession dropped petroleum product prices by about \$1 per gallon in 2009, prices have rebounded close to pre-recession levels, and have fallen slightly recently.

This study found that average U.S. product prices decline an average of 1.4–2.3 cents per gallon between 2015 and 2035 due to crude oil exports, with prices averaging \$2.60 per gallon over 2015 to 2035 with crude exports. This price decline could save American consumers up to \$5.8 billion per year, on average, over the 2015–2035 period. Price declines due to crude exports are largest in 2017 in the High-Differential Scenario, with U.S. product prices dropping 3.8 cents. This price drop translates to consumer fuel savings of \$9.7 billion that year. These declines are attributable to a larger global petroleum product supply made possible by a larger crude supply when the U.S. exports crude oil (see Section 4.1). Over the study period, product prices will still grow relative to historical levels because of continued strong global demand, but stronger global supply in the With Exports Case leads to lower product prices overall. This price decline is similar in magnitude to another study of crude exports and impacts on U.S. pricing.⁴⁹

⁴⁹ A recent Resources for the Future (RFF) study found that lifting the U.S. crude oil export restrictions would result in a decrease in the wholesale price of gasoline by 1.7 to 4.5 cents per gallon.

The WORLD Model uses an assumed international (market) crude price, as well as freight costs between markets to effectively model global pricing and arbitrages in forecasting refinery operations. These forecasts, which affect petroleum products such as gasoline and diesel, highlight the global nature of petroleum product costs, in that they drop when U.S. crudes are allowed to impact international oil prices and U.S. refineries are, in parallel, able to operate more efficiently.

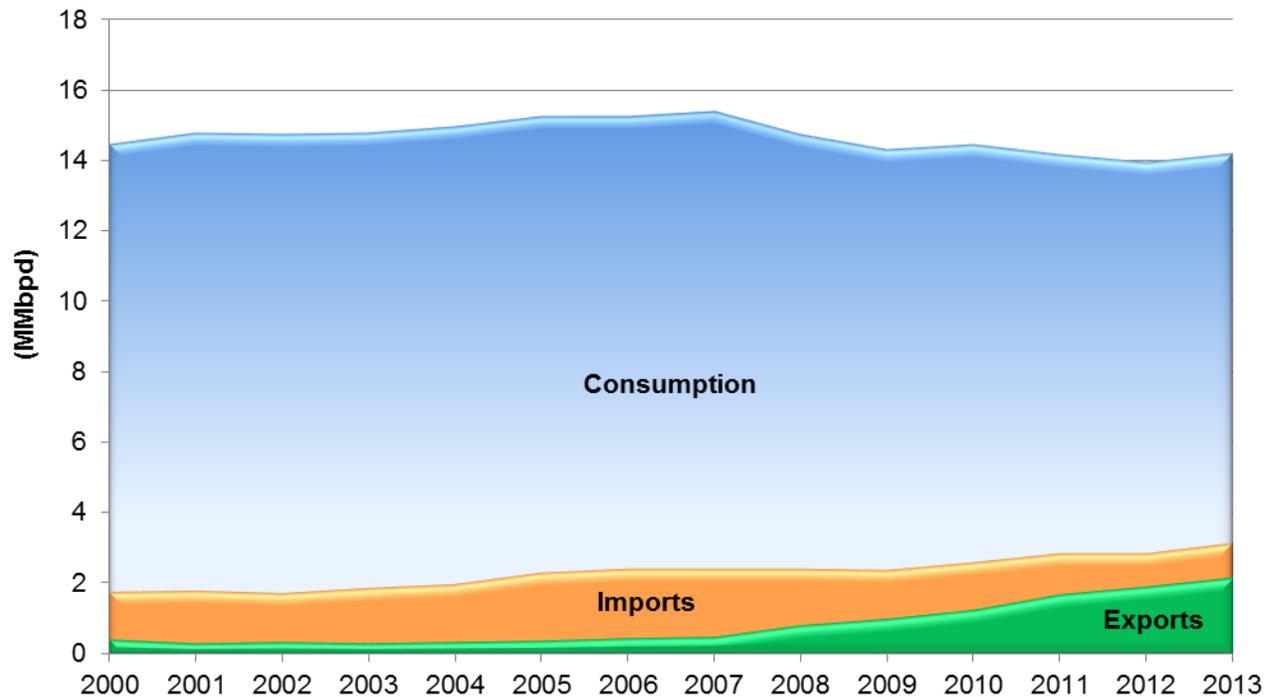
Exhibit 4-23: Weighted Average U.S. Wholesale Product Price Impacts



Sources: Historical – ICF analysis of EIA data; projections – EnSys WORLD Model and ICF analysis

The United States has long participated in the international trade in refined petroleum products. Between 2000 and 2013, U.S. trade in major refined petroleum products (gasoline, distillates such as diesel and heating oil, jet fuel, kerosene, and propane) increased from 1.8 MMBPD in 2000 to 3.1 MMBPD in 2013, as shown in the exhibit below. Over the period, imports have trended down slightly, while exports have increased from 0.4 MMBPD to 2.2 MMBPD. Imports and exports now comprise 22 percent of consumption, up from 12 percent in 2000. This trend illustrates that a large portion of U.S. product supply has either been imported from or exported into the global markets.

Brown, Stephen P.A.; Charles Mason; Alan Krupnick; and Jan Mares. "Crude Behavior: How Lifting the Export Ban Reduces Gasoline Prices in the United States." Resources for the Future (RFF), February 2014: Washington, D.C. Available at: <http://www.rff.org/RFF/Documents/RFF-IB-14-03-REV.pdf>

Exhibit 4-24: Consumption and Trade of Selected U.S. Petroleum Products*


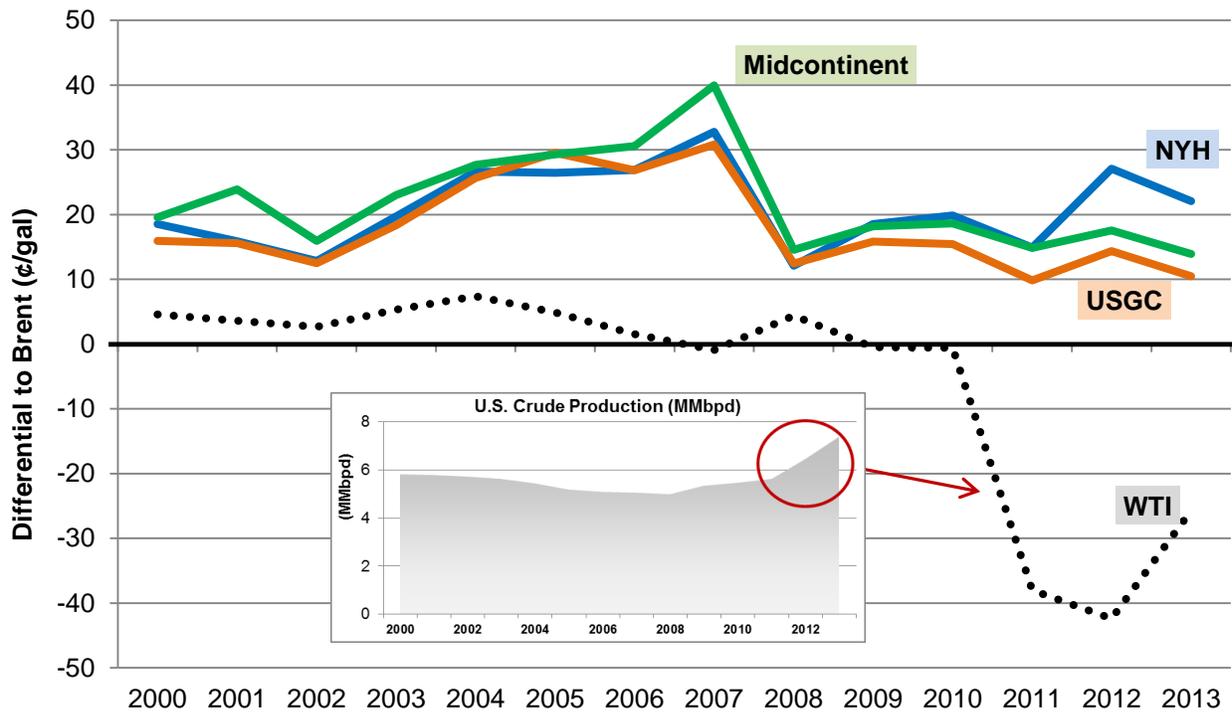
Source: U.S. Energy Information Administration (EIA). "Prime Supplier Sales Volumes." EIA, 25 February 2014: Washington, D.C. Available at: http://www.eia.gov/dnav/pet/pet_cons_prim_dcu_nus_m.htm U.S. Energy Information Administration (EIA). "Petroleum and Other Liquids: Exports." EIA, 25 February 2014: Washington, D.C. Available at: http://www.eia.gov/dnav/pet/pet_move_exp_dc_nus-z00_mbbldpd_m.htm U.S. Energy Information Administration (EIA). "Petroleum and Other Liquids: Imports." EIA, 14 March 2014: Washington, D.C. Available at: http://www.eia.gov/dnav/pet/pet_move_imp_dc_nus-z00_mbbldpd_a.htm

* Includes gasoline and gasoline blendstocks, distillates, jet fuel, kerosene, and propane

The cost of delivered crude oil and the value of the primary products from refining impact the U.S. refining sector. U.S. refiners are competing with global suppliers (traders and foreign refiners) who have the ability to bring product into the U.S. market or purchase product in the U.S. market to export. U.S. refiners supply both domestic and international demand, and also receive product from international sources. In recent years U.S. refiners have benefitted from relatively lower domestic crude and natural gas prices to sustain or increase crude runs (despite lower domestic demand) and export gasoline, diesel and propane to global markets at prices which support processing the crude oil.

As shown in Exhibit 4-25, the discount in WTI prices after 2010, relative to international competitors such as Brent crude, did not translate to lower U.S. refined product prices. This was the case even in the midcontinent, where WTI is physically bought and sold. The midcontinent region is short of refinery capacity to meet its own demands and imports product from the Gulf Coast at Gulf Coast product price levels to balance supply and demand.

Exhibit 4-25: U.S. Petroleum Product Prices Linked to Global Crude Prices



Source: Prices – Bloomberg. Crude production – U.S. Energy Information Administration (EIA). “U.S. Field Production of Crude Oil.” EIA, February 2014: Washington, D.C. Available at: <http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPUS2&f=M>

Note: Group 3 refers to Midcontinent 87 octane gasoline prices (Bloomberg ticker: G3OR87PC Index), NYH refers to New York Harbor (NYH) 87 octane gasoline prices (Bloomberg ticker: MOINY87P Index), USGC refers to U.S. Gulf Coast (USGC) 87 octane gasoline prices (Bloomberg ticker: MOINY87P Index). WTI refers to West Texas Intermediate (WTI) crude oil spot price (Bloomberg ticker: U.S.CRW TIC Index). Brent refers to Brent crude oil spot price (Bloomberg ticker: EUCRBRDT Index). Prices on graph show the differential to Brent prices.

Although the impact on global crude prices is relatively modest, this translates into lower international petroleum product prices, which then determine U.S. petroleum product prices. (The continuing free flow of import and export trade in products between the U.S. and other countries, and the ability to move products between regions within the U.S., notably coastal and inland, ensure U.S. product prices remain connected to and therefore determined by international market prices. Analysis of recent historical price data confirms this.)

Refinery gross margins are calculated based on the difference between the refinery feedstock inputs (primarily the cost of crude oil) and outputs (such as gasoline, diesel, and other refined petroleum products). This study found that allowing U.S. crude exports would reduce U.S. refinery margins for two reasons:

- 1) Higher refinery input costs: With export restrictions in place, domestic crude prices are depressed, relative to international prices. Lifting the export restriction increases U.S. crude oil prices as light U.S. crude oils, in particular, are able to flow into international markets and approach world price levels. In contrast, U.S. prices are discounted relative

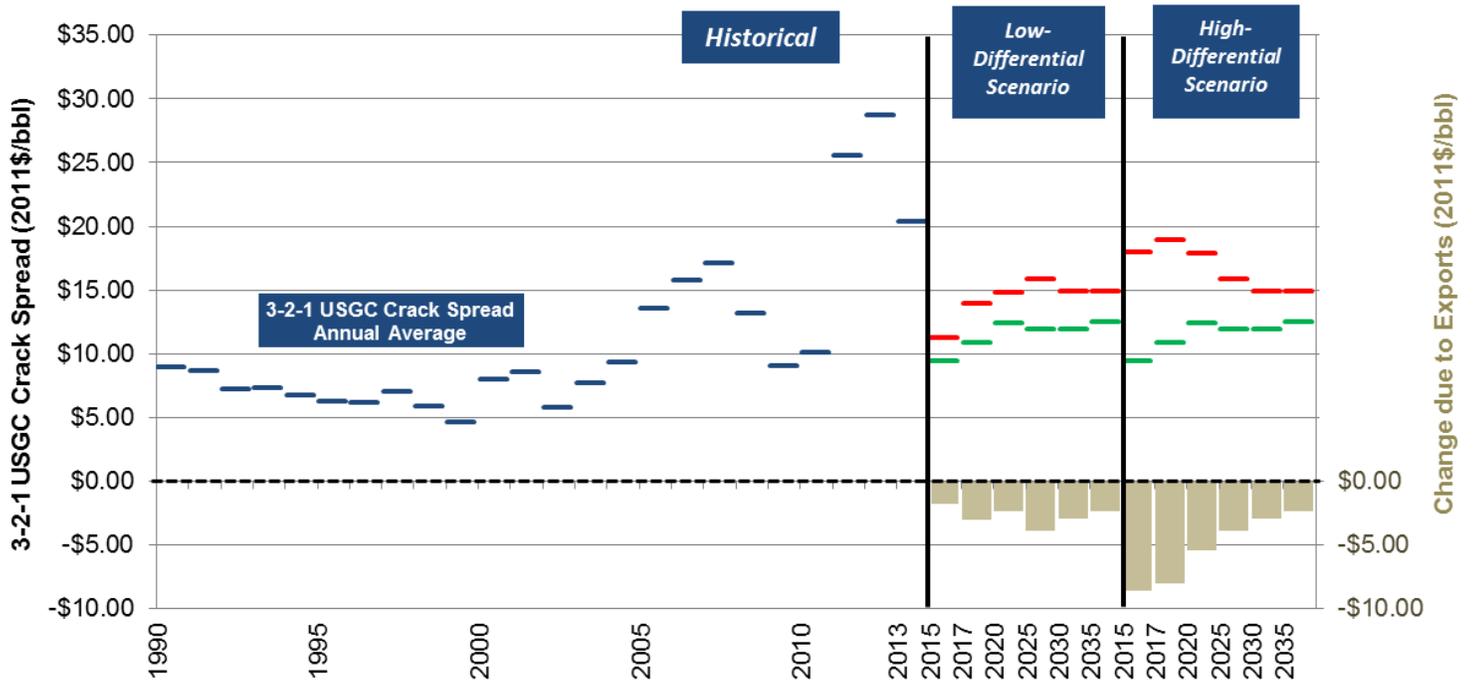
to world prices when domestic crude must be processed within the U.S. because exports are not allowed.

- 2) Slightly lower petroleum product values: Consumer petroleum product prices are largely determined by global product prices because U.S. imports and exports of petroleum products are not restricted. If U.S. crude exports were allowed, average consumer petroleum product prices would drop slightly as U.S. crude production and thus global supplies increase, dropping international oil prices slightly, and, by extension, U.S. petroleum product prices.

ICF projections of the differential when exports are not allowed vary depending on the scenario setup. In the Low-Differential Scenario, the impact of crude export restrictions on the differential increases through 2025 due to increasing U.S. tight oil production and then narrows after 2025 as U.S. production slows down. The High-Differential Scenario assumes higher inertia in crude pricing, thus a more dramatic WTI price depression in the short term, but the long-term impact due to export restriction becomes closer to that of the Low-Differential Scenario with No Exports to reflect long-term trends in U.S. crude production.

It is important to note that even with this decline due to exports, refinery margins will remain consistent with historical rates over the past 25 years and may see a slight improvement. As Exhibit 4-26 shows, historical 3-2-1 crack spread⁵⁰ in the Gulf Coast as based on WTI crude largely stayed below \$10 until 2010. Due to the tight oil revolution, WTI crude became depressed throughout 2011–2013 whereas petroleum product markets, which remain closely linked to global markets, did not experience a pass-through of crude price reduction. This has translated into quite high 3-2-1 crack spreads in recent years, giving a boon to U.S. refineries. ICF expects crack spreads to return to more normal levels over the study period, at between \$9.40 and \$12.50/bbl when exports are allowed. In other words, lifting export restrictions lessens the distorted situation seen recently in oil markets.

⁵⁰ The 3-2-1 crack spread is an easily calculated but approximate indicator of refinery profitability. It is calculated as the cost of **three** barrels of crude (here WTI) subtracted from the wholesale value to **two** barrels of gasoline plus **one** barrel of distillate oil.

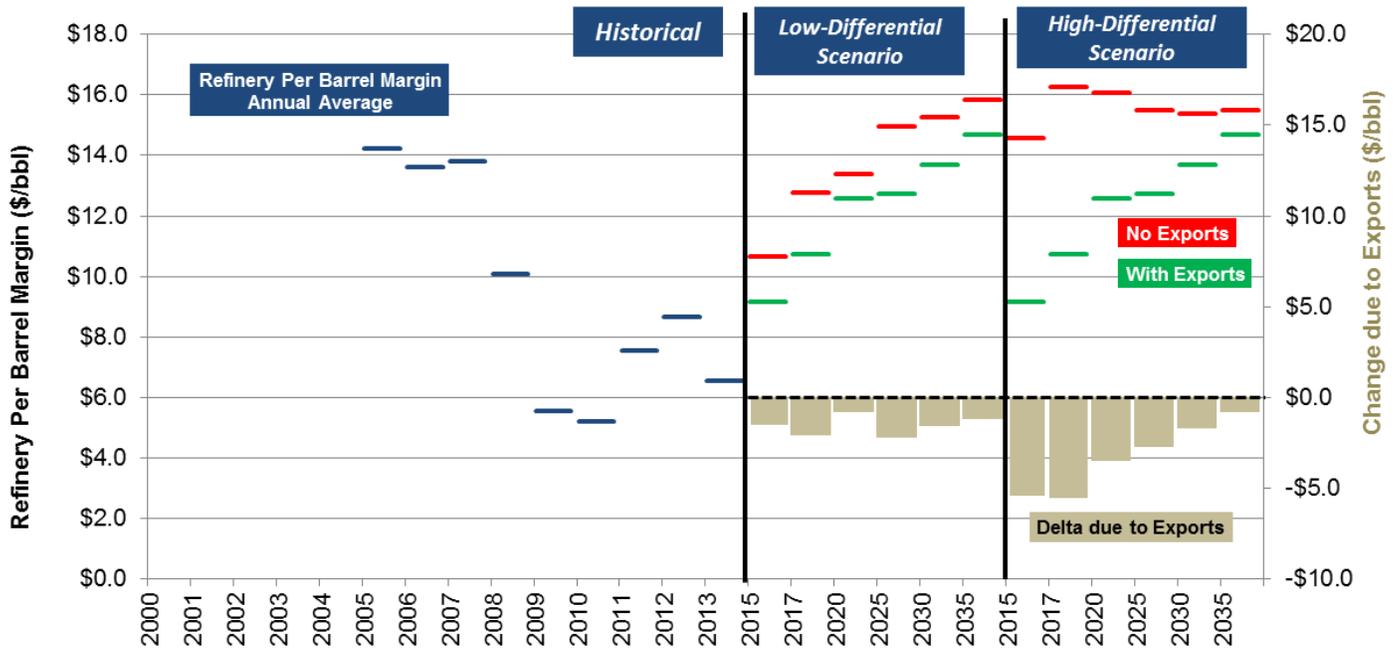
Exhibit 4-26: 3–2–1 U.S. Gulf Coast Crack Spread


Sources: EIA – historical; EnSys WORLD Model and ICF analysis – projections

Note: Historical data are nominal dollars and the forecasts are in real 2011 dollars.

The increase in domestic crude prices is much larger than the reduction in world crude oil prices, and so the average cost of crude to U.S. refineries goes up more than do refined product prices. This is the major reason why refinery margins (the difference between the value of the products they produce versus the cost of their crude inputs) decline. For reference, gross refinery margins (which do not include deductions for capital and non-feedstock operating costs) averaged \$14.23/bbl in 2005, and dropped to \$6.54/bbl in 2013. Per-barrel refinery margins are projected to average \$12.75/bbl over the period to 2035 when crude exports are allowed, roughly \$1.50/bbl lower than when exports are restricted in the Low-Differential Scenario, or \$2.85/bbl lower in the High-Differential Scenario with export restrictions.

Exhibit 4-27: U.S. Refinery Margin Impacts



Sources: EIA – historical; EnSys WORLD Model and ICF analysis – projections

Note 1: Historical data are nominal dollars and the forecasts are in real 2011 dollars.

Note 2: Data not available between 2000 and 2004.

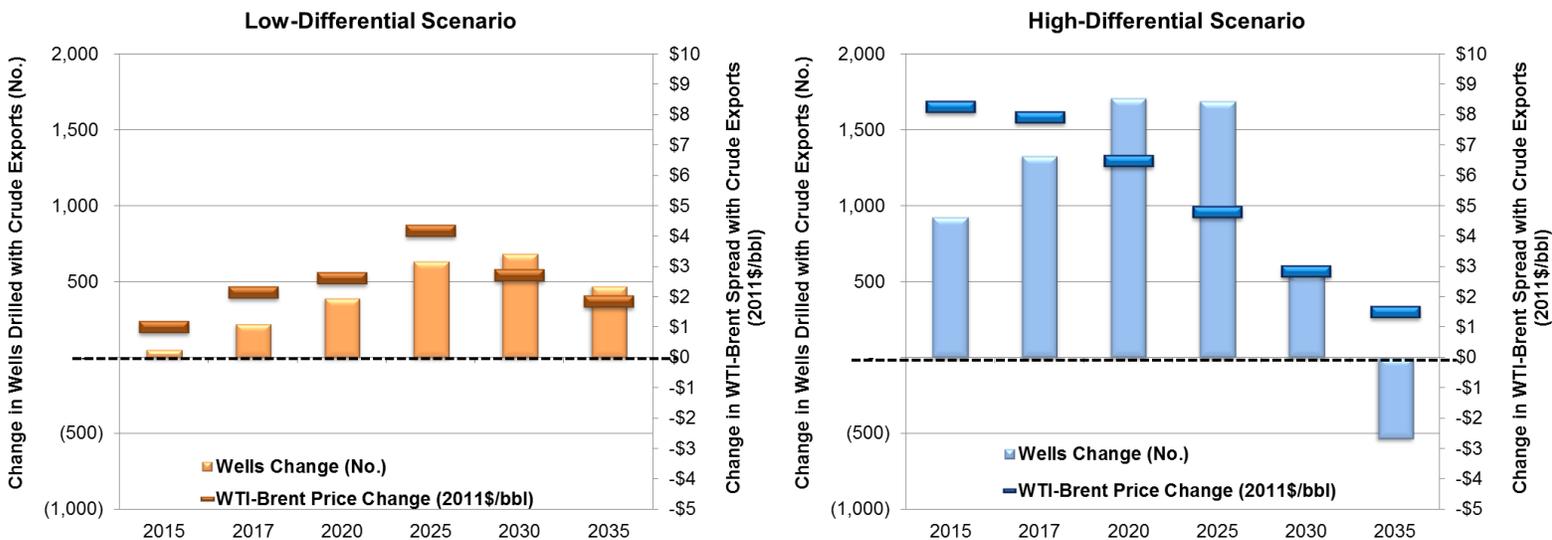
5 Employment and Economic Impacts of Crude Exports

The Low- and High-Differential Scenario employment and economic trajectories were determined by the calculated differences in drilling activity and other economic indicators between the With Exports and No Exports cases over the forecast period. The bulk of U.S. production growth is expected to be from tight oil production, so well drilling trends and the associated employment and economic activity follow tight oil production trends. The drilling activity is, in large part, a function of U.S. crude oil prices. When prices increase, drilling activity, likewise, increases as a price increase generates additional revenue to producers.

Crude oil exports create a larger difference in drilling activity and production in the High-Differential Scenario in comparison to the Low-Differential Scenario, particularly in the early years. However, over the long term, WTI-Brent price differentials with and without crude exports in the High-Differential Scenario are closer to those in the Low-Differential Scenario. Thus, the impacts on drilling levels and production are similar. In the very last years of the forecast, the drilling impacts are greater in the Low-Differential Scenario because wells are delayed in the High-Differential Scenario without exports (leading to less difference in drilling compared to the with exports cases).

Exhibit 5-1 below shows the drilling activity and WTI-Brent price differential changes attributable to lifting crude export restrictions. As shown in the columns in the left-hand chart, drilling activity changes due to crude exports being lower in the Low-Differential Scenario relative to the High-Differential Scenario, as shown in the right-hand chart. The driving force behind these well drilling changes is well economics driven by the WTI-Brent price differentials, as illustrated by the dashed lines in both charts.

Exhibit 5-1: Tight Oil Drilling Activity and WTI-Brent Price Differential Changes due to Crude Exports



Source: ICF and EnSys analysis

ICF assessed a number of economic and employment impacts due to relieving crude export constraints. Based on ICF's study findings, as discussed, the primary categories included were:

- Hydrocarbon production – Relieving the crude oil export constraint stimulates U.S. hydrocarbon production. This study assessed the increase in crude oil, lease condensate, natural gas, and natural gas liquid (NGL) volumes, shipment value, GDP contributions, and employment changes from lifting the crude oil export constraint.
- Petroleum refineries – Lifting the crude export restrictions both increases U.S. oil prices and puts downward pressure on global and U.S. petroleum product prices. Thus, refinery gross margins are reduced by both an increase in input costs, and a decline in output revenues. This study assessed the refinery sector changes due to lifting the crude export restriction, examining changes in U.S. refinery throughput, refinery investment changes, refiners' acquisition of crude costs (RACC), import price changes, and the weighted average price changes of U.S. petroleum products. The study assessed the volume, shipment value, GDP contributions, and employment changes due to lifting the crude export restrictions in the refinery sector.
- Consumer fuel savings – U.S. petroleum product prices decrease when crude export restrictions are lifted, as U.S. crude exports expands global crude supply, reducing global crude and petroleum product prices (and by extension, U.S. petroleum product prices). This study assessed the total consumer fuel savings attributable to lifting the crude export restrictions, as well as the GDP and employment impacts as these savings are spent throughout the economy.
- Import-export port services – Expanding crude exports results in additional marine transport activity, increasing U.S. port fees on both import and export of crude oil and petroleum products resulting from a release of the crude export constraints. This study assessed the volume increase in import/export activity, as well as the port service value, GDP contributions, and employment changes attributable to crude exports.
- Transportation sector – Lifting the crude export restrictions alters U.S. petroleum transportation primarily through increasing flows of additional crude production and altering flow patterns. This study quantified the transportation sector impacts of lifting the crude export restrictions in terms of changes in interregional and intraregional flows, as well as changes in flows to and from Canada. The study also quantified the GDP and employment impacts on the transportation sector of lifting the crude export restrictions.

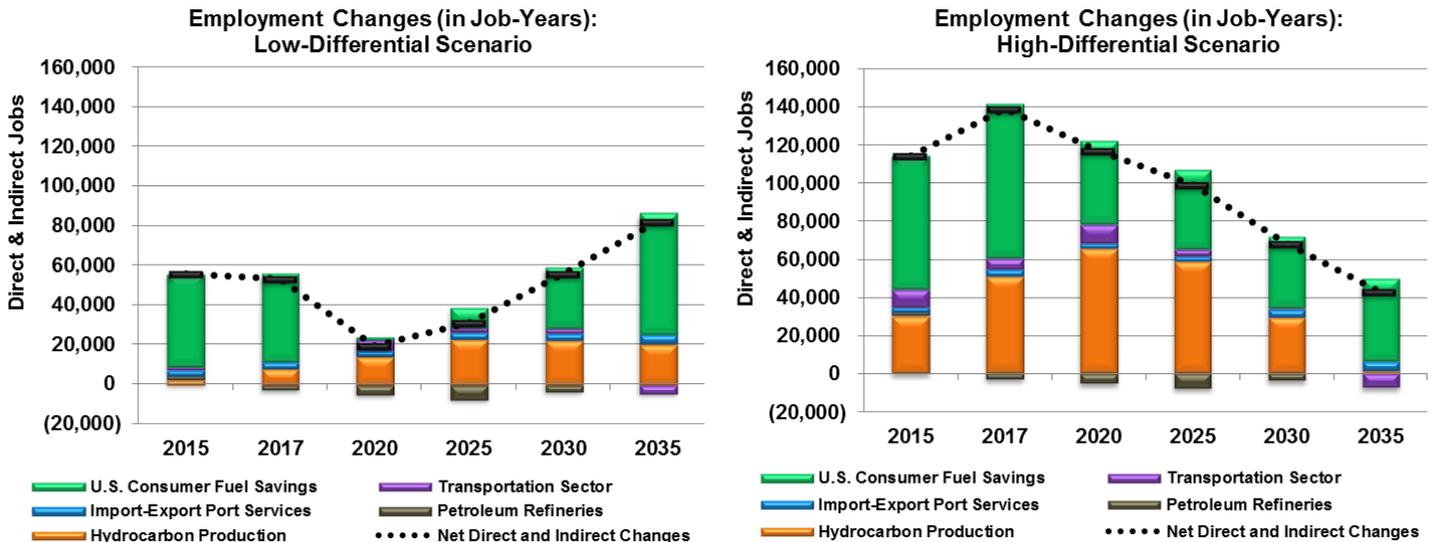
The employment and economic impacts discussed below show the differences between the With and Without Exports Policy cases for the Low- and High-Differential Scenarios. The Low-Differential and High-Differential scenarios for the With Exports Policy cases are the same. Differences between the Low- and High-Differential scenarios are entirely due to the differences in the two No Exports Policy cases. Therefore, employment, GDP, and government revenue impacts due to crude exports are different between the Low- and High-Differential scenarios. When calculated impacts between the With and Without Exports Policy cases are smaller, this indicates that the crude prices in the With and Without Exports Policy cases are relatively close. In contrast, years that show larger employment, GDP, and government revenue changes

indicate that U.S. crude price differences are wider between the With and Without Exports Policy cases.

5.1 Employment Impacts

ICF calculates direct and indirect employment impacts relative to the trend of no exports by multiplying the change in production in a given sector, measured in dollars or physical units times the labor needed per unit of production. Over the forecast period, crude exports are projected to increase net direct and indirect employment by an average of 48,000 and 91,000 jobs in the Low-Differential and High-Differential scenarios, respectively. Direct and indirect job gains are predominately due to money spent in the economy from fuel savings and from increased oil and gas development. Therefore, employment gains will most likely be in consumer-related and oil- and gas-related sectors. Exhibit 5-2 below shows the sources of direct and indirect employment changes associated with lifting the crude export restrictions.

Exhibit 5-2: Direct and Indirect Employment Increases due to Crude Exports



Source: ICF analysis

Note 1: Excludes multiplier effect (or induced) employment impacts.

Note 2: A job-year represents a single job occurring over 12 months or equivalent amounts of employment, such as two jobs occurring for six months each.

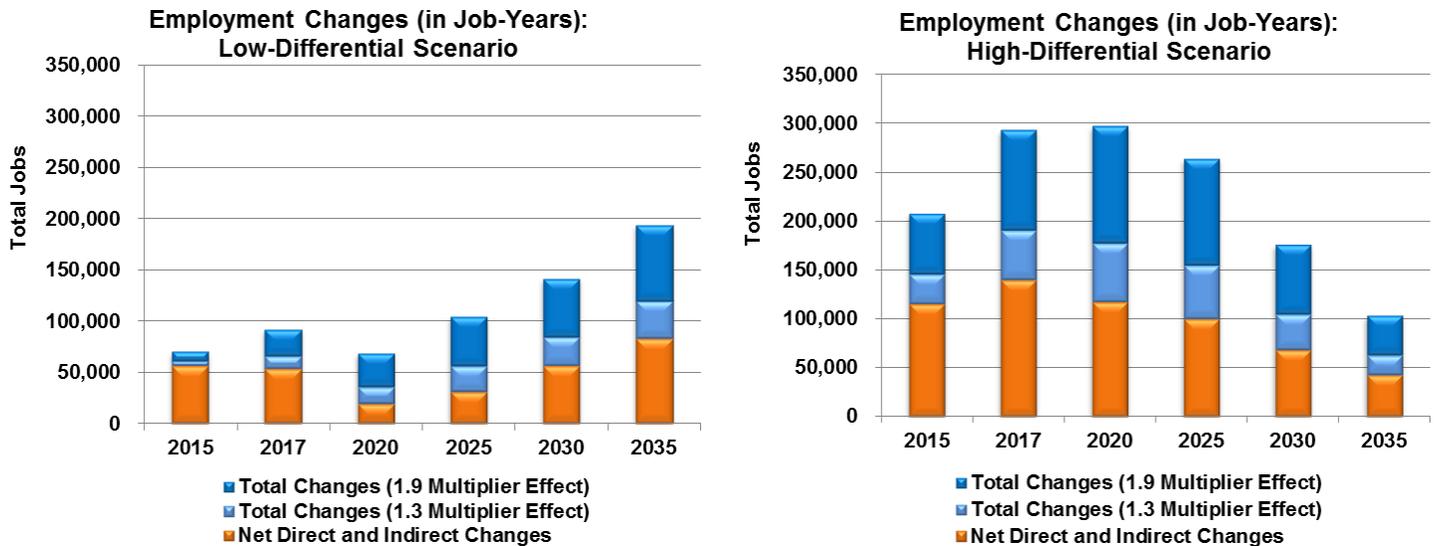
Total employment gains are projected to be higher than just the direct and indirect effects (see Exhibit 5-3 below). Additional income generated in the direct and indirect sectors is spent throughout the economy, supporting additional employment. Employment gains could reach up to 300,000 jobs in 2020 when crude exports are allowed, led by consumer products and services and hydrocarbon production sectors.⁵¹ Employment gains are expected to average nearly 72,000–118,000 jobs annually between 2015 and 2035 in the Low-Differential Scenario,

⁵¹ Based on the 1.9 multiplier effect.

and between 134,000-220,000 jobs in the High-Differential Scenario, with ranges based on the multiplier effect range.

As with GDP changes discussed below, the trajectory of employment changes between the Low-Differential and High-Differential scenarios are heavily impacted by WTI price changes between the With Exports and Without Exports Policy cases.

Exhibit 5-3: Total Employment Goes up when Crude Exports Are Allowed



Source: ICF analysis

Note 1: Multiplier effects can be higher when there is slack in the economy (not at full employment) and less when the economy is running near capacity. Hence, the estimated total employment impacts are shown as a range.

Note 2: A job-year represents a single job occurring over 12 months or equivalent amounts of employment, such as two jobs occurring for six months each.

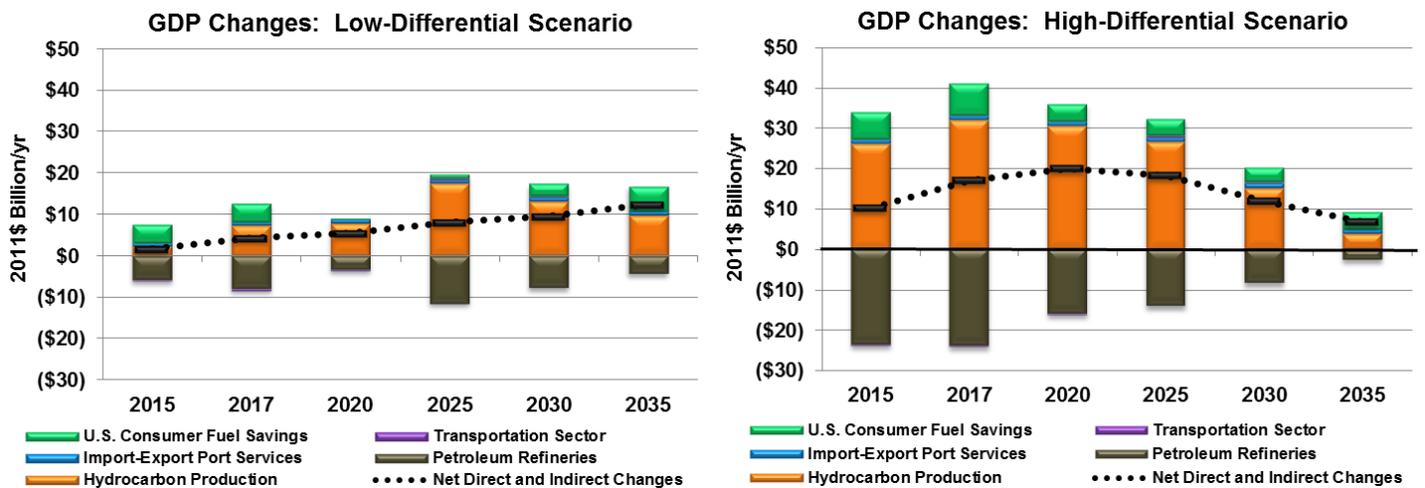
5.2 GDP Impacts

The ICF methodology calculates direct and indirect GDP impacts (relative to the base case trend of no exports) by assessing the change in relevant sectors and impact on GDP. Direct and indirect GDP changes attributable to crude oil exports include:

- The market value of additional crude oil and other hydrocarbon (such as associated natural gas and NGLs) production
- Changes in revenues to petroleum refineries due to changes in throughput and margins
- Increase in import-export port fees for additional crude oil exports
- Changes in the transportation sector revenues as crude oil exports alter pipeline and rail routes
- Increases to U.S. consumers as crude oil exports reduce global oil prices and volatility (and by extension, U.S. petroleum prices, which remain heavily influenced by global prices)

Lifting the restrictions on crude exports results in economic gains, mostly from increasing U.S. crude oil production. This change in production stimulates indirect activities such as the manufacture of drilling equipment and increases demand for steel pipe, cement, and other materials, as well as equipment and services. In addition, the hydrocarbon production sector GDP changes includes increased benefits to mineral-rights owners, as incremental impacts are due to both a projected increase in volume and a projected relative increase in price. Additional hydrocarbon production royalties average \$2.0 billion annually between 2015 and 2035 in the Low-Differential Scenario, and \$4.0 billion annually in the High-Differential Scenario. Impacts from consumers spending their fuel savings on other areas of the economy is the second largest source of direct and indirect GDP changes. From 2015 to 2035, crude exports increase direct and indirect GDP by an average of \$7.8 billion to \$14.3 billion per year, depending on scenario. Net economic impacts are positive in all forecast years.

Exhibit 5-4: Allowing Crude Exports Adds to Direct and Indirect GDP



Source: ICF analysis

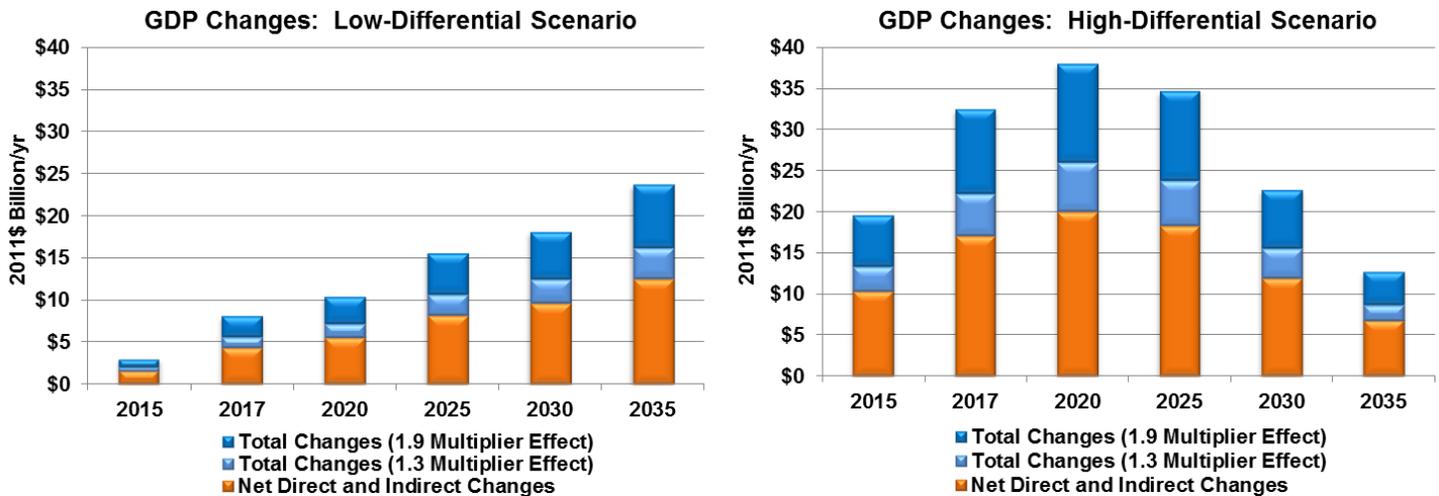
Note: Excludes multiplier effect (or induced) GDP impacts.

The main GDP declines are from the reduction in the calculated contribution to GDP (value added) from the petroleum refining sector. Higher domestic crude costs, slightly lower U.S. and global petroleum product prices, and lower refiner margins, therefore, decrease the GDP contribution per unit. However, the volume of refined product produced in the United States is similar in all cases. U.S. refinery operations, including employment, are similar in all scenarios.

Beyond direct and indirect GDP impacts, there are induced or “multiplier” effects. This represents the economic impacts as incremental income is spent throughout the economy by employees in the direct and indirect sectors. Given the uncertainty surrounding multiplier effects, this study applied a range of 1.3 to 1.9 for the multiplier effect. Generally, when the economy has a lot of slack, the multiplier is higher, since there are unused resources available. Lower multiplier effects are seen in economies near full employment. This means that every \$1 of direct and indirect GDP generates an additional \$0.30 to \$0.90 of additional GDP due to additional consumer spending throughout the economy.

Over the 2015 to 2035 forecast period, total GDP increases (direct, indirect, and induced GDP changes) due to crude exports are expected to average between \$10.1–\$14.8 billion in the Low-Differential Scenario, and between \$18.6–\$27.1 billion in the High-Differential Scenario, depending on the multiplier effect. The High-Differential Scenario has the largest WTI-Brent differentials in the early years when exports are restricted. Potential GDP impacts of releasing crude exports are expected to reach a maximum of \$38.1 billion per year in 2020 with the High-Differential Scenario.⁵²

Exhibit 5-5: Total GDP Increases when Exports Are Allowed



Source: ICF analysis

Note: Multiplier effects can be higher when there is slack in the economy (not at full employment) and less when the economy is running near capacity. Hence, the estimated total GDP impacts are shown as a range.

5.2.1 Government Revenue Impacts

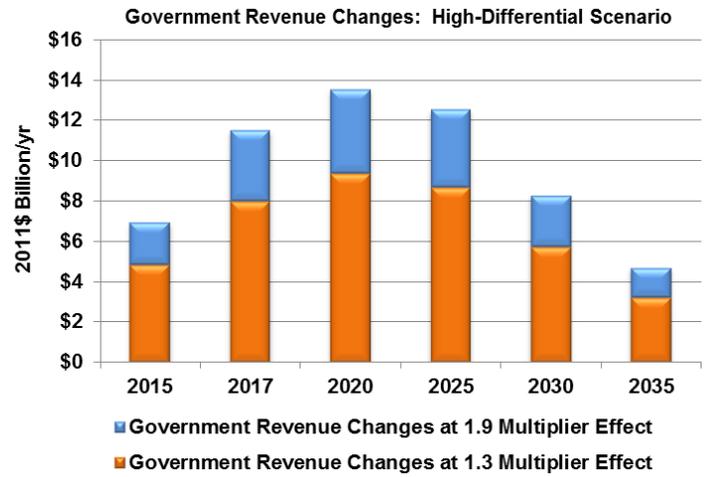
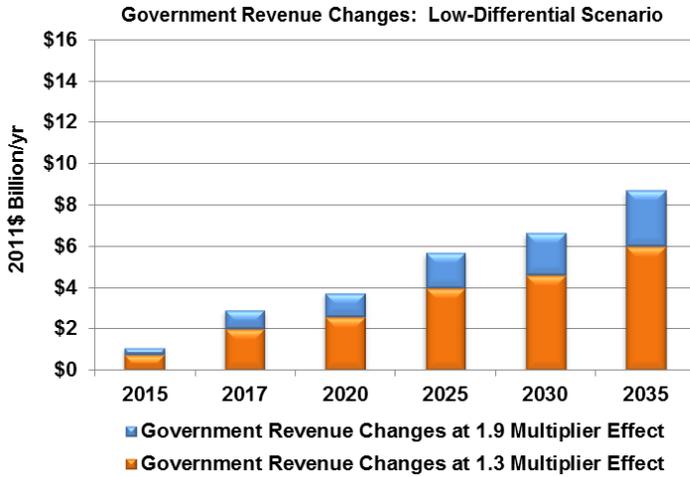
Federal, state, and local governments benefit from crude oil exports both in terms of the generation of GDP, which is then taxed at these levels, but also through royalties on federal lands where drilling takes place. Total government revenues, including U.S. federal, state, and local tax receipts attributable to GDP increases from expanding crude oil exports, could increase up to \$13.5 billion in 2020.⁵³ ICF calculated that crude exports are expected to cause government revenues to increase an annual average of \$3.7 to \$5.4 billion over the forecast period in the Low-Differential Scenario, and \$6.7 to \$9.7 billion in the High-Differential Scenario, depending on the multiplier effect. Government revenues include taxation on the following categories: employee compensation, proprietor income, indirect business tax, household taxes, and corporate taxes. Government revenue increases due to crude exports are led by an increase in federal, state, and local tax receipts due to the increase in GDP, as well as a slight increase in federal land royalties for hydrocarbon production. Federal tax receipts comprise roughly 54 percent the total, with state and local taxes (including severance taxes for oil

⁵² *Ibid.*

⁵³ *Ibid.*

production) comprising an additional 44 percent. Roughly two percent come from federal land royalties due to additional hydrocarbon production.

Exhibit 5-6: Government Revenue Changes

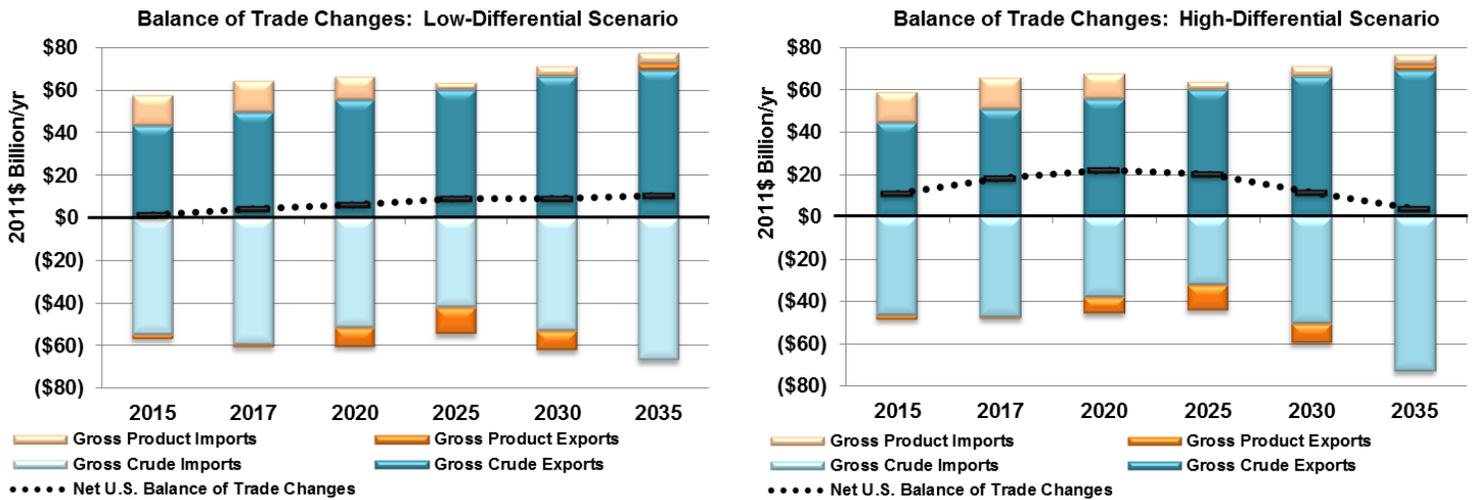


Source: ICF analysis

5.3 Balance of Trade Impacts

The change in exports and imports of crude oil and petroleum products attributable to lifting the crude oil export restriction results in a reduction of the U.S. trade deficit. Crude oil exports could narrow the U.S. trade deficit by \$22.3 billion in 2020 through increased international trade of U.S. crude oil. The net U.S. balance of trade changes are expected to average \$7.6 billion in the Low-Differential Scenario and \$14.6 billion in the High-Differential Scenario over the period 2015 to 2035. Balance of trade gains to the U.S. due to crude exports are led by gross crude exports and an increase in net product exports.

Exhibit 5-7: Balance of Trade Changes due to Crude Exports



Source: ICF analysis

Note: Increases in gross import values shown as negative values, due to the negative impact on the U.S. balance of trade. This means that an increase in the gross import value (increasing the U.S. international trade deficit) is shown as negative, whereas a decrease in gross import value (decreasing the U.S. international trade deficit) is shown as positive.

Exhibit 5-8 below shows U.S. goods exports by category. The items highlighted in yellow are major commodities and materials, which together make up roughly 20 percent of U.S. goods exports between 2011 and 2013. Crude oil and petroleum products are now the second largest goods export category. Allowing crude exports would mean crude and petroleum product exports would likely become the U.S.' largest goods export category.

Exhibit 5-8: U.S. Historical Goods Exports (\$ Millions)

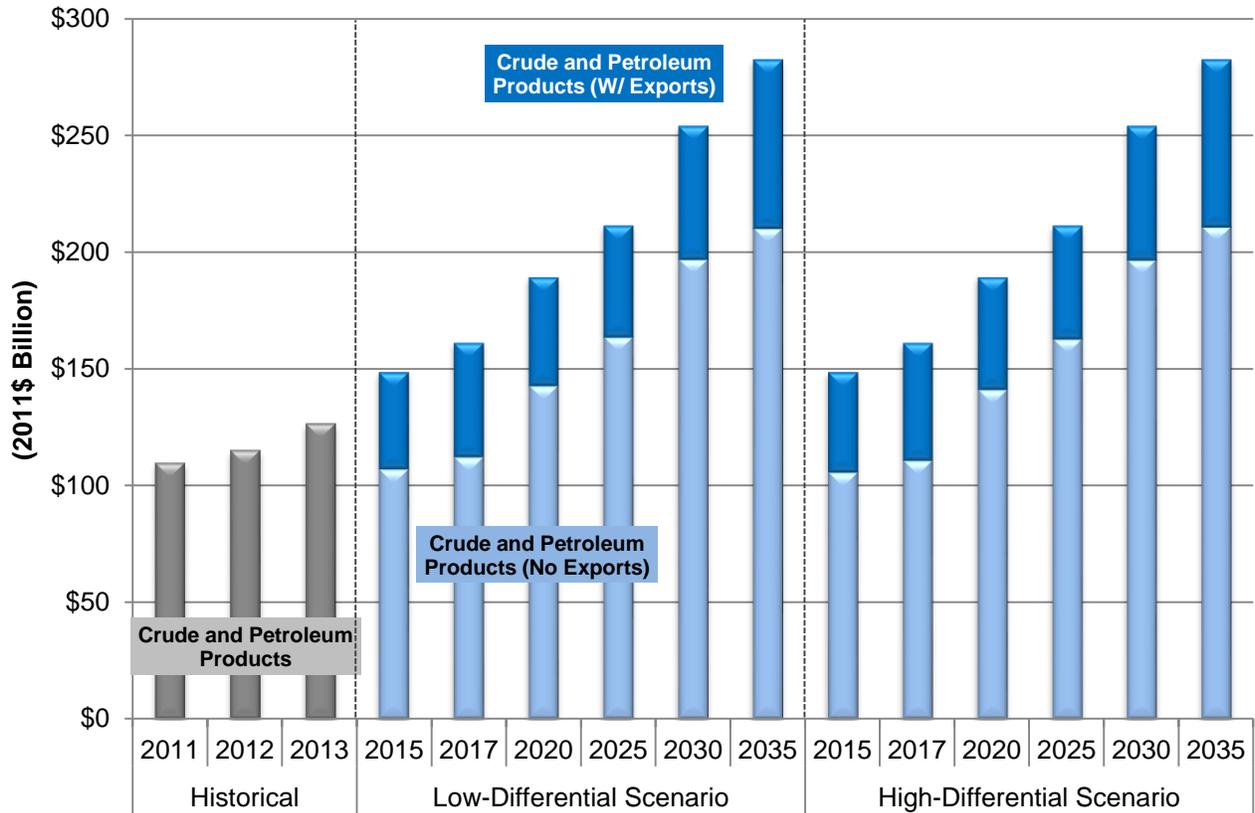
Item	2011	2012	2013
Automotive vehicles, parts, and engines	132,849	146,126	152,095
Crude oil and petroleum products	109,509	119,182	130,006
Civilian aircraft	33,386	45,375	54,398
Industrial machines, other	45,294	46,168	48,803
Pharmaceutical preparations	44,962	47,903	47,938
Semiconductors	44,713	42,067	42,580
Electric apparatus	35,286	38,288	40,138
Telecommunications equipment	35,859	38,552	39,711
Plastic materials	36,019	35,301	36,174
Chemicals—organic	39,538	35,536	35,419
Medicinal equipment	32,033	33,646	34,086
Nonmonetary gold	33,927	36,599	33,345
Computer accessories	31,556	32,326	31,362
Chemicals—other	28,759	29,497	30,378
Engines—civilian aircraft	26,256	27,643	29,659
Industrial engines	28,145	30,029	29,200
Measuring, testing, control instruments	23,837	24,820	24,751
Other industrial supplies	23,064	23,757	24,682
Cell phones and other household goods, n.e.c.	20,479	21,626	23,594
Soybeans	18,091	25,992	22,933
Parts—civilian aircraft	20,546	21,348	21,490
Gem diamonds	19,229	18,114	20,909
Finished metal shapes	17,993	19,493	20,206
Meat, poultry, etc.	17,130	18,022	18,463
Computers	16,838	16,942	16,689
Materials handling equipment	15,748	18,071	15,290
Excavating machinery	16,682	17,588	14,714
Generators, accessories	13,024	14,673	14,180
Newsprint	13,489	13,166	13,377
Other foods	10,749	12,009	12,862
Drilling & oilfield equipment	10,865	12,397	12,247
Jewelry, etc.	9,063	10,266	11,763
Toiletries and cosmetics	9,859	10,649	11,310
Iron and steel mill products	12,498	12,254	11,118
Photo, service industry machinery	10,234	11,119	11,073
Laboratory testing instruments	10,668	10,902	10,980
Wheat	11,306	8,336	10,687
Steelmaking materials	14,847	12,507	10,675
Toys, games, and sporting goods	10,512	10,451	10,276
Minor categories of goods below \$10b/year (excl. crude oil)	397,510	399,473	404,039
Total for All Goods	1,480,290	1,545,709	1,578,893
Sum of Major Commodities and Materials	309,126	320,972	328,080
Major Commodities and Materials as % of Exported Goods	20.9%	20.8%	20.8%

Source: U.S. Census Bureau. "U.S. International Trade in Goods and Services (FT900)," exhibits 6 and 7. U.S. Census Bureau, March 2014: Washington, D.C. Available at: www.census.gov/ft900

Note: Ranked by 2013 values. Line items highlighted in yellow indicate major commodities or materials.

Between 2011 and 2013, crude oil and petroleum products exports accounted for between 35 and 39 percent of major commodities and materials exports, or between seven percent and eight percent of total U.S. exports. This equates to annual crude and petroleum products exports of \$110–\$126 billion. Crude and petroleum products exports are expected to grow an additional 50 percent over 2013 levels by 2020, reaching nearly \$190 billion. By 2035, these exports are expected to near 125 percent over 2013 levels, totaling \$283 billion.

Exhibit 5-9: Gross Crude and Petroleum Product Exports



Sources: Historical – U.S. Census Bureau. “U.S. International Trade in Goods and Services (FT900),” exhibits 6 and 7. U.S. Census Bureau, March 2014: Washington, D.C. Available at: www.census.gov/ft900 Projections – ICF and EnSys analysis.

6 Conclusions

The analytic questions posed by consideration of policy options to remove restrictions of U.S. crude exports are complex in that they involve future U.S. oil production, current U.S. refinery capabilities and future investments, world crude oil prices, the pricing of petroleum products and the impacts of these factors on U.S. employment, GDP, and balance of trade. This study by ICF International (in cooperation with EnSys Energy) used historical data, scenario design, and forecasting models to quantify these various elements so as to provide logical and consistent information to support discussions of changes to current U.S. crude export policies.

The main conclusions of this study can be summarized as follows:

- U.S. oil production has been growing due to the application of horizontal well drilling and multi-stage hydraulic fracturing. U.S. oil production has increased by 2.1 million barrels per day (39 percent) over the last five years and is projected in this study to increase up to an additional 3.2 to 3.3 million barrels per day through 2020. The bulk of that future growth will be from tight oil production, but there will also be a substantial contribution from Deepwater Gulf of Mexico production.
- The ICF estimates of tight oil production used in the study are based on geologic assessment of various plays in the United States. In those assessments ICF has identified approximately 1,936 billion barrels of tight oil in place, of which approximately 54 billion barrels are technically recoverable under current technologies and practices and 104 billion barrels are expected to be recoverable by 2035 using evolving technologies and practices. The highest forecasts of tight oil drilling presented in this report represent 44 percent of this advanced technology resource base being developed by 2035.
- Historically, U.S. refiners were adapted to process heavier crude oil. However, the new and growing U.S. production is primarily light crude oil and lease condensate. Thus, there is a mismatch between U.S. refinery capabilities and the country's newfound supply.
- Since August 2013, the U.S. light crudes and condensates have experienced large differentials with comparable but higher price world crude such as Brent. Analysts have attributed these large differentials to U.S. refiners hitting constraints that prevent them from easily processing the growing U.S. light crude and condensate volumes.
- Refiners are planning some investments to better process lighter oils, but at the same time need to keep up with growing U.S. light crude and condensate production. There is a high probability that this differential between U.S. and comparable international crudes will persist for some time.
- This ICF analysis also suggests that if the timing of infrastructure development (pipelines, rail facilities, refinery investment, etc.) were to lag behind domestic crude production growth more significantly, even more reductions in crude prices and crude production may occur without the ability to export crude oil. Normal seasonal

maintenance activities at refineries that require reduced crude oil processing may put further downward pressure on crude oil prices and production at certain times of the year.

- Crude oil exports would provide a means for domestic producers of light crude oils and condensates to realize higher international value for their products. This would lead to greater investments and production of U.S. oil. ICF analysis estimates that additional U.S. oil production would mean \$15.2–\$70.2 billion in additional investment between 2015 and 2020, leading to an increase in U.S. oil production of 110,000 to 500,000 barrels per day by 2020.
- This ICF analysis suggests that if crude exports were allowed, it would not dramatically change U.S. refinery throughputs but would lead to an exchange in that the United States would export light crude oils and condensate and import more medium and heavy crude. Between 2015 and 2020, the additional U.S. exports of crude would be 1.2–1.5 MMBPD, offset by 1.5–1.6 MMBPD in additional imports. U.S. refiners would still import primarily heavy crudes and lube crudes to optimize the refinery performance. U.S. refinery throughput is expected to average 15.5 MMBPD over the forecast period without crude export restrictions, which is 100,000 barrels per day higher than with the restrictions.
- U.S. international trade in petroleum products is not subject to volume restriction for imports or exports and so U.S. product prices are set by international markets. Allowing U.S. crude exports reduces U.S. and world petroleum product prices by moderating world crude oil prices and allowing for more efficient refinery operations.
- This ICF analysis anticipates that this additional U.S. production will tend to moderate world oil prices slightly, and, by extension, U.S. petroleum product prices. U.S. weighted average petroleum product prices decline as much as 2.3 cents per gallon when U.S. crude exports are allowed. The greatest potential annual decline is up to 3.8 cents per gallon in 2017. These price decreases for gasoline, heating oil, and diesel could save American consumers up to \$5.8 billion per year, on average, over the 2015–2035 period.
- Allowing crude exports would reduce refinery margins due to higher domestic crude costs and slightly lower U.S. and global petroleum product prices. Because the volume of refined product produced is similar with and without exports, refinery employment is not projected to be significantly impacted.
- Employment supported by these GDP gains could near 300,000 jobs by 2020.⁵⁴ Employment gains are expected to average 118,000 jobs annually between 2015 and 2035 in the Low-Differential Scenario, and 220,000 jobs in the High-Differential Scenario.⁵⁵

⁵⁴ Based on the 1.9 multiplier effect.

⁵⁵ *Ibid.*

- U.S. GDP is estimated to increase up to \$38.1 billion in 2020 if expanded crude exports were allowed.⁵⁶ Over the 2015 to 2035 forecast period, GDP increases due to crude exports are expected to average \$14.8 billion in the Low-Differential Scenario, and \$27.1 billion in the High-Differential Scenario.⁵⁷ GDP increases are led by increases in hydrocarbon production and greater consumer product spending (due to lower prices for gasoline and other petroleum products).
- Lifting crude oil export restrictions could narrow the U.S. trade deficit by up to \$22.3 billion in 2020 through increased international trade of U.S. crude oil, or between \$7.6 and \$14.6 billion on average annually over the forecast period.
- Crude oil and petroleum products are now the second largest category of goods exported from the United States. Removing restrictions on crude exports will likely make them the largest category.

⁵⁶ *Ibid.*

⁵⁷ *Ibid.*

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8 Appendices

Appendix A: ICF International's Detailed Production Report

ICF International's Detailed Production Report

Providing Detailed Hydrocarbon Production Results from ICF's Gas Market Compass

ICF's Detailed Production Report provides a complete outlook for U.S. and Canada natural gas, natural gas liquids (NGL), and oil production from 2007 through 2035. The report presents annual production projections for over 50 different areas throughout the U.S. and Canada, and summed results across the U.S. and Canada.

Information Provided

- Natural Gas Production
- Natural Gas Liquids Production
- Crude Oil Production
- Gas Well Completions
- Oil Well Completions
- Total Well Completions
- Oil, gas, and NGL Recoveries by Well Type
- Decline Curves for Each Region
- Vintage Production Charts Showing Total Production and Production Declines

Detailed Information is Presented in Spreadsheet Tables and Charts

- **Regional Tables** provide production and well activity in tabular format for each region. Tables also provide recoveries per well.
- **Regional Charts** provide decline curves and vintaged production charts for each region.
- **U.S. Tables** provide summed production and well activity along with well recoveries for the U.S. in total.
- **U.S. Charts** provide vintaged production charts for the U.S. in total.
- **Canada Tables** provide summed production and well activity along with well recoveries for Canada in total.
- **Canada Charts** provide vintaged production charts for Canada in total.
- **U.S. and Canada Tables** provide summed production and well activity along with well recoveries for the U.S. and Canada in total.
- **U.S. and Canada Charts** provide vintaged production charts for the U.S. and Canada in total.
- **Database Tables** provide the detailed information, over 250,000 rows of data, for all regions in a database format.

Regional Coverage

- Alaska
- Alberta and Saskatchewan Conventional and Tight
- Alberta CBM
- Anadarko Woodford Shale
- Antrim Shale
- Appalachia Other
- Arkla Conventional and Tight
- Arkoma Woodford Shale
- Avalon & Bone Springs
- Bakken Shale
- British Columbia Conventional and Tight
- California EOR
- Denver Niobrara
- Denver Tight
- Denver-Park-LA
- Eagle Ford Shale
- Eastern Canada Offshore/Other
- Fayetteville Shale
- Fort Worth Barnett Shale
- GOM Deepwater
- GOM Shelf
- Granite Wash
- Gulf Coast Conventional and Tight
- Haynesville Shale
- Horn River Shale
- Jonah-Pinedale
- Marcellus Shale
- Michigan and Illinois
- Mississippi, Alabama, Florida
- Montney Shale
- North Central TX Conventional and Tight
- Northern Midcontinent Conventional and Tight
- Other Alberta Shales
- Other W TX Shales
- Pacific Offshore
- Pacific Onshore Other
- Paradox Basin Shales
- Permian Basin Conventional and Tight
- Piceance Basin
- Powder River CBM
- Powder River Niobrara
- Raton CBM
- San Juan CBM
- San Juan Other
- Southern Midcontinent Conventional and Tight
- SW WY and NE UT Other
- Uinta Basin
- Uinta-Piceance Other
- Utica Shale
- Virginia CBM
- Warrior CBM
- Williston Basin
- Wind River and Big Horn Basins
- Wolfberry

ICF International (NASDAQ:ICFI) partners with government and commercial clients to deliver professional services and technology solutions in the energy and climate change; environment and infrastructure; health, human services, and social programs; and homeland security and defense markets. The firm combines passion for its work with industry expertise and innovative analytics to produce compelling results throughout the entire program life cycle, from research and analysis through implementation and improvement. Since 1969, ICF has been serving government at all levels, major corporations, and multilateral institutions. More than 3,500 employees serve these clients worldwide. ICF's Web site is www.icfi.com.

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