An IHS Energy / IHS Economics Report

US Crude Oil Export Decision

Assessing the impact of the export ban and free trade on the US economy






IHS

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Study Purpose

Rapidly increasing crude oil production and limited refining capacity for these types of crudes are raising questions about the current US policy of banning crude oil exports. This report assesses the impact of a change in export policy—to free trade—and compares it to the impact of maintaining the current restrictive trade policy. The analysis also examines the historical context in which current export policy was developed in the 1970s and identifies how the world oil market—and the US position in it—has changed significantly since that time.

This report draws on the multidisciplinary expertise of IHS—including upstream, downstream and macroeconomic teams across IHS Energy Insight and IHS Economics. The study has been supported by a group of sponsors. The analysis and conclusions contained in this report are entirely those of IHS Inc., which is solely responsible for the contents herein.

Since the onset of the "Great Revival" in US natural gas and crude oil production, IHS has provided continuing analysis of this development, its prospects both in North American and around the world, and its impact on the US economy and its competitiveness in the world economy. Some of the current studies include:

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See more at: http://press.ihs.com/press-release/economics/us-unconventional-oil-and-gas-revolution-increase-disposable-income-more-270#

GOING GLOBAL: PREDICTING THE NEXT TIGHT OIL REVOLUTION

Going Global: Predicting the Next Tight Oil Revolution examines the widespread geological potential of tight oil globally. The study identifies the 23 highest-potential plays throughout the world and found that the potential technically recoverable resources of just those plays is likely to be 175 billion barrels—out of almost 300 billion for all 148 play areas analyzed for the study. While it is too early to assess the proportion of this that could be commercially recovered, the potential is significant compared to the commercially recoverable resources of tight oil (43 billion barrels) the IHS estimated for North America.

Going Global provides a comprehensive assessment of the potential of tight oil plays outside of North America, where well-level data does not currently exist. (IHS CERA Multi-Client Study)

See more at: http://press.ihs.com/press-release/energy-power/ihs-study-north-americas-tight-oil-phenomena-poised-go-global#

For more information on these and related studies, contact Jamey.Rosenfield@ihs.com

***US Crude Oil Export Decision* Study Sponsors**

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Baker Hughes, Chesapeake Energy, Chevron U.S.A., Concho Resources, ConocoPhillips, Continental Resources, Devon Energy, ExxonMobil, Halliburton, Helmerich & Payne, Kodiak Oil & Gas, Nabors Corporate Services, Newfield Exploration, Noble Energy, Oasis Petroleum North America, Pioneer Natural Resources, QEP Resources, Rosetta Resources, Weatherford, Whiting Petroleum.

KEY FINDINGS

- The 1970s-era policy banning oil exports—a remnant of a price controls system that ended in 1981—is creating growing market distortions and needs to be revisited in light of rising US oil production and the expanded domestic resource potential.

- The US oil system is nearing "Gridlock" with the mismatch between the rapid growth of light tight oil and the inability of the US refining system to economically process these growing volumes. The result is a widening discount, which will reduce drilling investment, jeopardizing oil production growth, reducing jobs, and hurting the US economy.

- Lifting the export ban and allowing free trade will, in our base case, increase US production—from 8.2 million B/D currently to 11.2 million B/D—and add investment of nearly $750 billion. The "unconventional" revolution in oil and gas has also been one of the major contributors to the US economic recovery, estimated by IHS to have added nearly 1% to our GDP in each of the past two years.

- By boosting global supplies, the elimination of the ban will result in lower global oil prices. Since US gasoline is priced off global gasoline prices, not domestic crude prices, the reduction will flow back into lower prices at the pump—reducing the gasoline price 8 cents a gallon. The savings for motorists is $265 billion over the 2016-2030 period.

- The higher US oil production resulting from a lifting of the ban will create at its peak 1 million jobs, increase GDP by $135 billion, and increase per household income by $391. The nation's oil import bill is reduced by $67 billion per year, a 30% reduction from the 2013 level.

- Lifting the ban supports economic activity across all states. A quarter of the additional jobs are in states that essentially produce no crude oil.

Industry and economic results provided in the table below and on the previous page compare the free trade impact—versus the current restricted crude oil trade policy—using the base case production outlook. Presented in the study is also a potential case for US production that results in greater impact from free trade.

Impact of Free Trade (vs. Current Restricted Trade Policy)	
	Base Production Case
Crude Oil Production, average, 2016-2030 (million B/D)	1.2
US Gasoline Price, average, 2016-2030 (cents per gallon, real)	-8
Fuel Cost Savings, cumulative, 2016-2030 ($ billion)	265
Investment	
Peak Annual Investment ($ billion)	66 in 2017
Cumulative Investment, 2016-2030 ($ billion)	746
Gross Domestic Product	
Peak Growth (percent)	0.7 in 2018
Peak ($ billion, real)	135
Average, 2016-2030 ($ billion, real)	86
Net Petroleum Trade, average, 2016-2030 ($ billion, real)	67
Employment	
Average, 2016-2030 (thousand)	394
Peak (thousand)	964 in 2018
Disposable Income per Household	
Average, 2016-2030 ($, real)	238
Peak ($, real)	391 in 2018
Cumulative Government Revenue (2016-2030) ($ billion)	1,311

Source: IHS Energy Insight and IHS Economics

EXECUTIVE SUMMARY

This report assesses the impact of a change in crude oil export policy to free trade and compares it to maintaining the current policy, which generally bans crude exports. The analysis also examines the historical context in which current export policy was developed during the 1970s. It identifies how dramatically the world oil market—and the US position in it—has changed since that time and how the rationales from the 1970s have faded away.

IMPORTANCE OF CRUDE OIL EXPORT POLICY

A secure supply of oil—and keeping a lid on gasoline prices—is a fundamental US interest. It is supported across the political spectrum because of its importance to the economy, the daily livelihood of Americans, and energy security. Policy regarding crude oil exports will play a key role in shaping how successfully the US accomplishes these objectives in the years ahead.

Since the 1970s, the United States has effectively banned the export of crude oil. The ban was a reaction to the tumult and crises in the world oil market—the 1973 oil embargo against the United States, the nationalization of oil-producing assets held by Western companies, and the 1978 Iranian Revolution. It was also a response to the conviction that the United States was “running out of oil”.

But closer examination finds that the ban was even more specific to the 1970s and the debates of those years. One purpose was to ensure that new North Slope oil coming through the Alaska pipeline was not shipped to Asia. The other was an essential part of the abstruse system of the 1970s oil price controls—to prevent cheaper “old oil” from earning a higher price on the world market. The oil price control system was completely eliminated in 1981. But the ban on exports, a key element of that system, remains in place 33 years later as the last vestige of a price control system long gone.

The export ban was aimed at ensuring US-produced crude oil would stay in the United States. However, this ban, until recently, was of little practical relevance. US crude oil production was in a long period of decline, falling by half between 1970 and 2008. Shrinking domestic output was readily accommodated by a refining system that was increasingly dependent on oil imported from far-flung sources. But the oil market that prevailed in the 1970s—and even as recently as the early 2000s—no longer exists.

THE GREAT REVIVAL IN US PRODUCTION

The United States currently is at the center of one of the most profound changes in the global oil industry since the 1970s. The decades-long decline in US production has been reversed—and in dramatic fashion. A Great Revival in US production is well under way. US crude oil output increased 64%—3.2 million barrels per day (B/D)—from 2008 through March 2014 and helped reduce global oil prices, even as other global crude supplies have faltered. This increase in US output is the fastest in the nation’s history and has exceeded the combined production gains from the rest of the world.

US domestic production growth has led to a decline in import dependence that not long ago would have seemed unimaginable. Net US dependence on imported oil shrunk from 60% of demand in 2005 to less than 30% in early 2014.

This “unconventional” revolution in oil and shale gas has also been one of the major contributors to the US economic recovery; it is estimated by IHS to have added nearly 1% to our GDP in each of the past two years. Will the growth in US domestic crude oil production continue? Geology and technology point toward further gains—and very large ones. According to the International Energy Agency (IEA), the United States is on the path to regain its prior status as the world’s largest crude oil producer within this decade.[1] The United States could continue to move towards

[1] International Energy Agency, World Energy Outlook 2013.

a further significant reduction in net imports. But none of this is guaranteed. The price of oil on the global market will have a big influence on production trends. So will US crude oil export policy, which is the subject of our study.

- In our Base Case, with the ban on US exports lifted, production will increase from its current level of 8.2 million B/D to 11.2 million B/D in 2022.
- But if the ban is not lifted, output will be 1.2 million B/D lower. The reason is that, if the ban remains in place, domestic oil will sell at an increasing discount, reducing the amount of investment in new production. The discount results from the nature of the US refining system, particularly along the Gulf Coast, where just over half of the nation's total refining capacity is located. Over $85 billion has been spent in the past quarter century to reconfigure these refineries to process heavy oil imported from countries like Venezuela, Mexico and Canada. As a result, there are limits to how much of the new, domestically produced light tight oil (LTO) the refining system can efficiently and effectively process.
- Allowing the export of crude oil would allow LTO to obtain world prices, which in turn would lead to higher investment—nearly $750 billion more investment—and to higher output.
- The economic benefits from the consequences of free trade in exports would flow through to the economy—and to every state—measured in additional GDP ($86 billion annually, on average) and nearly 1 million additional peak annual jobs.

WHY DOES US CRUDE OIL EXPORT POLICY MATTER?

US crude oil export policy will have a major impact in determining whether the United States regains its position as the largest crude oil producer in the world and acts as a force for lower gasoline prices. Today, the United States is the third largest crude oil producer, behind Russia and Saudi Arabia. Oil is also our largest energy source, providing 36% of our daily energy needs.

The existing restrictive trade policy has reduced the price that US producers receive for their crude oil relative to the global market. This is because they cannot sell their output outside the United States except under very limited circumstances.

At first glance, this may seem to be a positive for American consumers. If a US refiner purchases lower-cost domestic crude, wouldn't that translate into lower gasoline prices? This notion may be appealing, but it does not reflect market reality.

Gasoline connects US gasoline prices to the global market—and not to the price of domestically produced US crude oil. This creates a market distortion that disadvantages crude production in the United States relative to global production. Permitting US exports of crude oil would put additional supply onto the world market, lowering international crude prices and international gasoline prices. Lower international gasoline prices flow back into the US gasoline market, resulting in 8 cents per gallon lower prices at the pump for motorists. This creates a savings for consumers of $265 billion between 2016 and 2030.[2]

A big risk of the current restrictive export policy is that it will lead to even lower prices for US-produced crude oil, while gasoline prices will remain high. Discounted prices for US domestic crude oil—at a level and duration that would throttle back output gains—would occur because the US refining system cannot absorb all the potential growth in production. If low prices for US domestic crude endure—and that risk is growing—investment in crude oil production will slow or even decline. Export markets are needed to sustain US crude oil production gains that cannot be absorbed by our refineries without significant and costly changes to the US refining system.

[2] Allowing free trade is estimated to reduce the US real dollar gasoline price by 8 cents per gallon on average for the 2016-2030 period under the Base Production Case.

- The US refining system is the most flexible in the world, but even so is unable to efficiently absorb the quality and quantity of LTO being produced. Specifically, these refiners have too little capacity to process the light part of LTO and too much capacity for the heavy remaining portion of the barrel. As a result, a significant LTO price discount is needed to account for the suboptimal refining of LTO in these heavy crude refineries.
- US refiners' competitive advantage will be maintained under a policy change expanding US crude oil exports. The export of LTO from US shores would provide a competitively priced LTO feedstock (based on offshore market price minus freight cost) that would allow US refiners to economically supply both the domestic and export product markets. While the LTO price under free trade is not severely discounted as in restricted trade, the free trade price provides a competitive advantage relative to imported international crude. In fact, the relative price of LTO under free trade is similar to the price differential that existed from 2011-2013 for US Gulf Coast refiners, a period in which the United States became the largest refined products exporter in the world.
- There is discussion about a policy change that allows the export of condensate—a very light form of oil often derived from natural gas production—instead of a broader crude oil export policy. This would be an important interim step towards relieving the Gridlock and moving towards free trade. However, further changes would be needed to achieve the estimated free trade impacts presented. Moreover, a policy that permanently limits export trade to one type petroleum stream—no matter how carefully defined—could create another market distortion.
- Although not widely recognized, the United States is already a major exporter of refined products, including diesel, gasoline and jet fuel. At almost 4 million B/D, the United States has become the world's largest exporter of products. This is double the level of five years ago. Lifting the ban on exports of crude oil would be consistent with the new realities of US and world oil and would remove one of the last vestiges of the panic-induced policies of the 1970s.

A move to free trade in crude oil would help the United States realize its growth potential for crude oil production. By doing so, US domestic crude oil prices would become linked to the global market and would be a force for lower—not higher—gasoline prices. US crude exports would find ready markets for LTO exports in Europe and Asia. In Europe, it would back out competing crudes from Africa and potentially Russia, which would be reoriented to Asia.

IMPACT OF FREE TRADE VERSUS RESTRICTIVE TRADE

IHS has evaluated the crude export policy decision using two outlooks for US crude oil production. To this point, the impact of lifting the trade policy in the Base Case has been presented above. A more optimistic—but certainly realistic—Potential Case is provided below and throughout our report.

For each of the two production cases—the Base and Potential Cases—two policies were analyzed: free trade, which illustrates the impact of a move to allow exports of US-produced crude oil, and restricted trade, which assumes that the current ban is maintained. The forecast period for this analysis is 2016-2030.

IHS PRODUCTION FORECASTS

The IHS production outlooks integrate our geological and upstream exploration and production databases, the largest in the world, our extensive refining and oil market databases, our deep economic modeling and regional economics capabilities, and our in-depth experience and understanding of oil market dynamics and trends.

- The Base Case is predicated on the IHS central business planning forecast that provides a conservative view based on known defined plays and assumes limited technical improvements from current performance.
- The Potential Case includes additional known but less well defined areas of existing plays and moderate drilling performance & technology improvements in the future.

Free trade is projected to have positive impacts on job growth, trade, government revenues and economic output as shown below.

TABLE ES.1
Impact of Free Trade (vs. Current Restricted Trade Policy)

	Base Production Case	Potential Production Case
Crude Oil Production, average, 2016-2030 (million B/D)	1.2	2.3
US Gasoline Price, average, 2016-2030 (cents per gallon, real)	-8	-12
Fuel Cost Savings, cumulative, 2016-2030 ($ billion)	265	418
Investment		
Peak Annual Investment ($ billion)	66 in 2017	82 in 2017
Cumulative Oil Production-related, 2016-2030, ($ billion)	751	995
Cumulative Refining-related, 2016-2030, ($ billion)	-5	-21
Cumulative Investment, 2016-2030, ($ billion)	746	974
Gross Domestic Product		
Peak Growth (percent)	0.7 in 2018	1.2 in 2018
Peak ($ billion, real)	135	221
Average, 2016-2030 ($ billion, real)	86	170
Net Petroleum Trade, average, 2016-2030 ($ billion, real)	67	93
Employment		
Average, 2016-2030 (thousand)	394	859
Peak (thousand)	964 in 2018	1,537 in 2018
Disposable Income per Household		
Average, 2016-2030 ($, real)	238	466
Peak ($, real)	391 in 2018	733 in 2021
Cumulative Government Revenue (2016-2030) ($ billion)	1,311	2,804

Source: IHS Energy Insight and IHS Economics

Industry and economy benefits from free trade of crude oil include:

- The impact for the US economy of a free trade policy on crude exports is significant. The key driver is the difference between free and restricted trade for US oil production and investment, which increases 1.2 million B/D and $66 billion (peak) in the Base Production Case and 2.3 million B/D and $82 billion (peak) in the Potential Production Case.
- Gross domestic product (GDP) in the Base Production Case with free trade will peak in 2018 at $135 billion, or 0.7%, higher than with the current, restricted trade policy. The peak impact is greater in the Potential Production Case when GDP under free trade will be $221 billion, or 1.2%, higher.
- The impact of free trade and associated higher crude oil production on US petroleum trade is considerable.[3] The 2013 US bill for imported petroleum is calculated at $218 billion. Free trade reduces this bill by $67 billion (Base Production) and $93 billion (Potential Production) over restricted trade per year on average from 2016 through 2030. In overall terms, the oil bill will decline from its 2013 level of $218 billion to $48 billion by 2022 – equivalent to 78 percent of 2013 oil trade deficit.
- Increased economic activity will lead to greater job creation and a lower unemployment rate. Total US jobs increase due to free trade will be, on average, 394,000 in the Base Case and 859,000 in the Potential Case. Peak job creation in 2018 is nearly 1 million in the Base Case and over 1.5 million in the Potential Case. A stronger labor market with free trade relative to restricted trade will increase the average annual household's disposable income by $239 and $465 during 2016-2030 in the Base and Potential Production Cases, respectively.
- Government revenues from corporate, personal and energy-related taxes and royalties are expected to increase under free trade policy. The cumulative addition to revenue is $1.3 trillion from 2016 through 2030 in the Base Production Case and more than double—$2.8 trillion—in the Potential Production Case.
- Benefits from free trade of crude oil are distributed throughout the US. Jobs growth and economic benefits are continent-wide and not just in large oil producing states due to substantial supply chains supporting the field production, capital spending, transportation and refining of crude oil. For example, 24% of the future jobs supporting the oil industry are located in states that essentially produce no crude oil.

OIL MARKET CHANGES POINT TO POLICY CHANGE

Global trade in oil and gas has benefitted the global economy, including the United States. So why is the ban on US crude oil exports, which was a reaction to upheavals during the 1970s in the world oil market, still in place? This oil export ban is indeed one of the last vestiges of an antiquated system in which the federal government once set the price for oil, provided subsidies to refiners that imported crude, and allocated supplies around the country.

But the world and US oil industry have changed dramatically in the past four decades, and the US economy and consumers would benefit from an updated policy that responds to these changes by allowing exports of some of the nation's rising crude oil production. Removing the export ban would enhance energy security by strengthening the energy position of the United States, which would regain its stature as the world's largest producer of crude oil. Further, lifting the export ban would stimulate the economy, create new jobs, and reduce the prices that US consumers pay at the pump for their gasoline.

[3] Petroleum trade defined as the net imports (imports minus exports) of crude oil, refined products and NGLs.

I. INTRODUCTION

Nearly four decades after the establishment of laws and regulations severely restricting the export of US crude oil, rapidly rising domestic production is challenging the relevance of a policy that was implemented in a different era, an era of turmoil and shortage. It is also a policy that has had little effect until recently. But, owing to changed circumstances, it is now having a negative impact.

Lifting the effective ban on crude exports would bring important benefits. It would lead to more investment in the oil sector, which in turn would have positive effects on the overall economy in terms of economic growth and job creation. At the same time, given the structure of the global oil and gasoline markets, it would lead to lower prices for US gasoline—averaging 8 cents per gallon over the forecast.[4]

THE ORIGINS OF THE BAN ON EXPORTS

The ban on crude exports was adopted as part of a series of laws passed after the 1973 Oil Embargo and the four-fold increase in oil prices that followed immediately after. The embargo, followed by the Iranian Revolution in 1978-1979, created great concern about the availability of oil supplies in a period of declining domestic production, political outrage, growing gasoline lines and consumer panic.

The mood of the times was reflected in statements from legislative leaders. “The public is about to revolt,” said the chairman of one Senate committee in 1974. Another declared, “Our whole economy is reeling today—our lifestyle is threatened today—by shortages.” In its report on the 1975 legislation, a House committee declared:

> “The fundamental reality is that this nation has entered a new era in which energy resources previously abundant, will remain in short supply, retarding our economic growth and necessitating an alteration in our life’s habits and expectations…Even more important (than) the fiscal consequences of increased import dependency, this nation will become increasingly hostage to an interruption of these supplies.”[5]

In such circumstances, even the thought of exporting oil was enough to inflame public opinion—captured at the time in the words of one congressman:

> “I had what is commonly referred to as a town meeting in my district designed to take in both ends of the extremes in my district, very liberal meeting and very conservative…they told me at both meetings what they intended to do to any member they could vote for who did not limit every drop of oil that was produced in this country to stay in the country.”[6]

Price controls on crude oil and petroleum products had already been established prior to the oil embargo in an effort to fight inflation. The imposition of price controls and an effective price ceiling on crude oil and petroleum products were further legislated with the Emergency Petroleum Allocation Act (EPAA), passed a few weeks after the Oil Embargo. In many ways the EPAA was the key initiating legislative action placing the first official restrictions on total crude oil exports. In late 1973, crude oil was added to the commodity control list, under the Export Administration Act of 1969, placing significant restrictions on the export of crude oil.[7]

[4] Allowing free trade is estimate to reduce the US real dollar gasoline price by 8 cents per gallon on average from 2016-2030 period under the Base Production Case.
[5] Quotes from Cambridge Energy Research Associates, *In Search of Reasonable Certainty: Oil and Gas Reserves Disclosure* (2005), pp. 36-38.
[6] “Extension and Revision of the Export Administration Act of 1969: Hearings and Markup Before the Committee on Foreign Affairs, House of Representatives, Ninety-Sixth Congress, First Session, Part 2,” U.S. Government Printing Office, Washington D.C., 1980, p. 258.
[7] Robert Bradley, *Oil, Gas, & Government: The U.S. Experience Volume II* (Rowman & Littlefield Publishers, Inc., 1996), p. 770.

The Energy Policy and Conservation Act of 1975 was the next piece of legislation to ban crude oil exports in response to the Oil Embargo and OPEC's price increases. The 1975 legislation was an omnibus bill that included everything from the establishment of automobile fuel efficiency standards, energy efficiency standards for appliances, and the strategic petroleum reserve to low-income weatherization assistance and policies encouraging utilities to burn coal instead of natural gas. The most contentious part, however, was the political battle over the extension of price controls on oil.

As for the ban on crude oil exports, the legislative record indicates that it was little discussed. But such a ban was essential to keep the jerry-built system of price controls—"old oil" and "new oil", "lower tier oil" and "upper tier oil", stripper oil, "released oil"—from collapsing under its own complexity. The ban prevented price-controlled domestic oil from being exported into the higher-priced world market "to escape domestic price regulation."[8] The crude oil export policies were added to and modified with other laws, particularly through amendments to the Mineral Leasing Act of 1920. The Energy Policy and Conservation Act ban exports of crude oil except in a few very limited situations discussed further below.

By the time the export ban was further codified, in the 1979 Export Administration Act, the focus was very specifically on prohibiting exports to Japan of North Slope crude oil, which had begun to flow through the Trans-Alaska Pipeline in 1977. As one scholar wrote, "The legislative history makes clear" that the ban on oil exports "was directed against the export of oil produced from the Alaskan North Slope."[9] Ironically, the prohibition on exporting Alaskan crude was eliminated by President Bill Clinton in 1996. President Clinton concluded that lifting the ban would improve economic growth, reduce dependence on foreign oil and increase jobs without an adverse impact on gasoline prices. But the volumes of North Slope production have fallen so low as to mean that exports have not been economic. Nevertheless, the broader restriction persists even after its specific rationales—price controls, Alaskan oil—have expired.

In the years since, the United States has remained an oil importer. Energy security remains a priority concern and "energy independence" is an inherent part of political discourse. Yet much has also changed, including a dramatic transformation in America's oil position.

As for the oil export ban, it remains an artifact of another era when the federal government set oil prices, handed out import entitlements and allocated supplies. It was an era, as another scholar put it, when "the Federal Register became more important than the geologist's report." Direct government market management increased markedly. For example, the standard reporting requirements to what had become the Federal Energy Administration involved some 200,000 respondents from the private sector.[10] It was in that era that the federal government took on the responsibility of banning oil exports. But that time is long gone, along with the panic about shortages that defined it. All this provides the imperative to review the current crude oil export policy.

CURRENT REALITY

Since enactment of the crude export policy in the 1970s, a number of important changes in the oil industry, government regulation and markets demonstrate how antiquated the policy has become.

[8] *Oil and Gas Journal,* October 6, 1975.

[9] John. T. Evrard, "The Export Administration Act of 1979: Analysis of its Major Provisions and Impact on United States Exporters," *California Western International Law Journal, 1:1982, pp. 37-39*. The article concludes: "The prohibition on the export of domestically-produced crude oil is, therefore, an exception to the general policy of encouraging free trade. This prohibition, however, seems to lack any persuasive rationale."

[10] Daniel Yergin, *The Prize: the Epic Quest for Oil, Money, and Power* (New York: The Free Press, 2009), p. 642.

- Before the Great Revival of recent years in US oil output, crude production had declined from a peak of 9.6 million B/D in 1970 to 5.0 million B/D in 2008. Since the Great Revival began, output has rebounded to 8.2 million B/D as of March 2014 and further significant increases are expected. The IEA has predicted that the United States will become the world's largest oil producer by 2016.[11]
- Much of the US refining system is ill-suited to process light crude or LTO. The US refining industry has been rebuilt to process heavy crudes from Canada, Mexico and Venezuela, among other countries, over the last two decades. Over $100 billion has been invested to upgrade the Gulf Coast and Midcontinent refining complexes to process heavy oils, and this refining capacity is poorly configured to process the light low-sulfur crude oil now being produced in greater quantity, and this imbalance is already beginning to impose costs on refinery operations.[12] While the United States remains a net importer of medium and heavy crude oil, the light crude oil balance is becoming "Gridlocked" as production growth exceeds refining capacity for light crude oil, and that part of the market moves to oversupply without the ability to export. As a result, price distortions have emerged, and domestic light crude oil is discounted compared with similar quality international crudes. The supply and demand fundamentals suggest these distortions will grow over the coming years and become particularly acute during periods of high refinery maintenance.
- Another major change is how oil prices are determined. Oil prices have been decontrolled since 1981, and the industry's structure has changed dramatically. Price formation has shifted from the integrated commercial model of the 1960s and the government price regulation during the 1970s to the more transparent spot market price model of today. The ban on exports can be seen, in part, as the sole remnant of a price control system that disappeared more than three decades ago.
- The actual benefits of the crude oil export ban are elusive and hard to find and are likely to become negative. This is the case whether measured in terms of energy security or gasoline and other product prices. In contrast to the limitations on crude exports, refined products are freely traded, and the United States has become the largest exporter of refined products. With light crude oil in Gridlock, the ban will lead to reduced investment and lower production, which would decrease, not increase, US energy security.

HOW THE CRUDE OIL EXPORT RESTRICTIONS WORK

PRE-1970S EXPORT CONTROLS

Export controls, particularly during times of conflict and turmoil, have long been a standard legislative action in the United States and historically have typically involved a list of exceptions and allowances.

THE MANDATORY OIL IMPORT QUOTA SYSTEM

Prior to the Energy Policy and Conservation Act of 1975's ban on virtually all crude oil exports, US oil trade had been largely regulated by the Mandatory Oil Import Quota system put in place in 1959. Its aim was to limit foreign oil dependency and support domestic production.

The establishment of this program marked a historic change. From 1861 until 1947, the United States had been a net exporter of crude oil—for many years, by far the largest exporter. But with the post-war boom in demand and the arrival of Middle Eastern crude oil, the United States had become an importer. The quota program sought to reduce demand for imported crude by establishing import quotas on crude oil and refined products and imposing penalties on

[11] When including both crude oil and NGLs.
[12] Comments by Gary Simmons, Valero Energy Corp first quarter 2014 earnings conference call.

companies that exceeded their allowances. This program was designed to limit the amount of lower-cost foreign crude used by domestic refiners, thereby increasing demand for domestic crude, supporting prices and encouraging further investment in production. In addition to commercial considerations, the Eisenhower Administration, in the midst of the Cold War competition with the Soviet Union, recognized the strategic importance of US oil production during World War II and saw the maintenance of domestic oil production as a national security imperative.

The import quota system led to a two-tier pricing system, with insulated higher domestic prices delinked from lower international prices.

The multitude of revisions made to the Mandatory Import Quota under Presidents Kennedy, Johnson and Nixon show the market stresses caused by trying to regulate a multifaceted commodity and the increasingly unsustainable complexity required of the quota system.[13] This became particularly acute by the beginning of the 1970s when US production began to decline at a time of rising US demand. The mandatory program was officially terminated in 1973. By then, a new system of price controls was already in place, arising from inflation fears in the early 1970s. The price control system mandated a series of different price levels for different crude sources, creating the need for complex and confusing regulatory machinery and stimulating much litigation

AFTER THE OIL EMBARGO

The Energy Policy and Conservation Act of 1975 was the most comprehensive legislation after the 1973 oil embargo to place an overall ban on crude oil exports. It was followed by amendments to the Mineral Leasing Act of 1920 and the Export Administration Act of 1979. This legislation does allow for exchanges or exports of domestic crude of specific origin on the condition that the president make and publish findings that such exports would benefit the national interest.

In considering an exception to the export restriction, the president is required to “make and publish an express finding that such exports...will not diminish the total quantity or quality of petroleum refined within, stored within, or legally committed to be transported to and sold within the United States;”[14] although no standard of quality is given. It is hard to find any evidence today that free trade in oil would diminish the total quantity of petroleum available to the United States. Indeed, exports would do the opposite—increase the total quantity of oil available to the United States. Moreover, the record of recent oil crises is that well-functioning global markets are one of the best assurances of available supply.[15]

The amendments made to the Mineral Leasing Act appear to establish a formal process for lifting a crude oil export ban.

After determining that it is in national interest to allow specific crude exports, the president must submit reports to Congress detailing the reasons. Congress then has 60 calendar days to consider whether the exports are valid under the conditions outlined in the Mineral Leasing Act, and, if they are not, to pass a concurrent resolution of disapproval, causing exports to cease. The

[13] Jeffrey Bialos, "Oil Imports and National Security: The Legal and Policy Framework for Ensuring United States Access to Strategic Resources," University of Pennsylvania Journal of International Law, 11, no. 2 (1990): 235-300, https://www.law.upenn.edu/journals/jil/articles/volume11/issue2/Bialos11U.Pa.J.Int'lBus.L.235(1989).pdf (accessed February 24, 2014).
[14] Export Administration Act of 1979, PL 96-72, 93 Stat.503, section 7
[15] Daniel Yergin, *The Quest: Energy, Security, and the Remaking of the Modern World* (New York: Penguin, 2012), pp. 277-279.

Outer Continental Shelf Lands Act of 1953 prescribes similar export restrictions on crude oil produced offshore.[16]

EXCEPTIONS TO US CRUDE EXPORT RESTRICTIONS

The collection of legislation passed in response to the 1973 Oil Embargo resulted in a variety of regulations restricting (or allowing) the export of various types of crude oil and products, depending on origin and destination, that are still applicable today. The definition of crude oil as presented in the Export Administration Regulations Short Supply Controls document is the standard used by the Department of Commerce's Bureau of Industry and Security (BIS) in granting export licenses. Crude oil's definition reads as follows:

> Crude oil is defined as a mixture of hydrocarbons that existed in liquid phase in underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities and which has not been processed through a crude oil distillation tower. Included are reconstituted crude petroleum, and lease condensate and liquid hydrocarbons produced from tar sands, gilsonite, and oil shale. Drip gases are also included, but topped crude oil, residual oil, and other finished and unfinished oils are excluded.[17]

Additionally, the major exceptions to the ban on crude exports are enumerated. The assumption of approval is outlined for the following origins and destinations (although each came with differing volume and transport limitations, such as the use of higher cost Jones Act compliant vessels):[18]

(i) Exports from Alaska's Cook Inlet

(ii) Exports to Canada for consumption or use therein

(iii) Exports in connection with refining or exchange of strategic petroleum reserve oil

(iv) Exports of heavy California crude oil up to an average volume not to exceed 25,000 B/D

(v) Exports that are consistent with international agreements

(vi) Exports that are consistent with finding made by the President under an applicable statute

(vii) Exports of foreign origin crude oil where the exporter can demonstrate that the oil is not of US origin and has not been comingled with oil of US origin

(viii) Certain crude oil from the Strategic Petroleum Reserve

In all cases, including those in which crude exports are authorized as above, an export license must be granted by the BIS. In fiscal 2013, approved crude oil licenses were the category with the highest transaction value for the BIS. Unlike export licenses for liquefied natural gas (LNG), the crude oil (and condensate) export license process is not public at any phase in the process. This difference in transparency is due to the nature of oil export licenses, which are granted on a commercially sensitive cargo-by-cargo basis, rather than the more generalized flow and time period basis in use for natural gas exports. Applications for export crude or condensate are made to the BIS, by the company requesting the license. If the application is covered in one of the major exceptions, the request is generally granted in short order.

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[16] Outer Continental Shelf Lands Act, August 7, 1953, Chapter 345, as amended through Dec 29, 2000 http://www.epw.senate.gov/ocsla.pdf.
[17] Bureau of Industry and Security, U.S. Department of Commerce, Short Supply Controls, https://www.bis.doc.gov/index.php/forms-documents/doc_view/425-part-754-short-supply-controls.
[18] Bureau of Industry and Security, U.S. Department of Commerce, Short Supply Controls, https://www.bis.doc.gov/index.php/forms-documents/doc_view/425-part-754-short-supply-controls.

In cases where the request to export is outside of the standard exceptions, applicants can discuss the request with BIS staff. Applications must be resolved within 90 days or referred to the president, although there are exceptions to this timeline to allow BIS to consult with other relevant government agencies or request additional information from the applicant. The BIS has recently received and/or granted several licenses to re-export crude. While the number and range of applications may provide some additional flexibility for relieving some aspects of the Gridlock, any substantive change in the policy to allow significantly higher crude exports and eliminate Gridlock, will need to come from outside the BIS.

CONFUSION IN CRUDE EXPORT RESTRICTIONS

While crude oil exports are expressly forbidden, complications ensue when analyzing condensates and some natural gas liquids (NGLs). The BIS Short Supply Controls supplement categorizes NGLs—"natural gas liquids" that are produced from a gas well—under petroleum products, thereby implying that they may be exported without restriction.[19] The list of NGLs counted as petroleum products includes ethane, propane and butane—provided they have a minimum purity of 90% liquid volume, although the lack of clarity regarding the process used to make these products could leave open questions regarding the legal status of exports.[20]

Condensates, as traditionally defined by the oil industry, are low-density, high-API gravity liquid hydrocarbons whose presence, as a liquid phase, depends on temperature and pressure. Conditions in the reservoir that facilitate condensation of liquid from the vapor phase would fall into the category of crude oil.[21] However, the varying liquidity based on temperature at the time of production implies condensates produced during warmer months, which typically end up in natural gasoline (defined by the government as a mix of pentanes plus heavier molecules), can be legally exported. Despite this, condensates produced in colder months, which are more likely to leave the ground as liquids, would be subject to the crude oil export restrictions.[22]

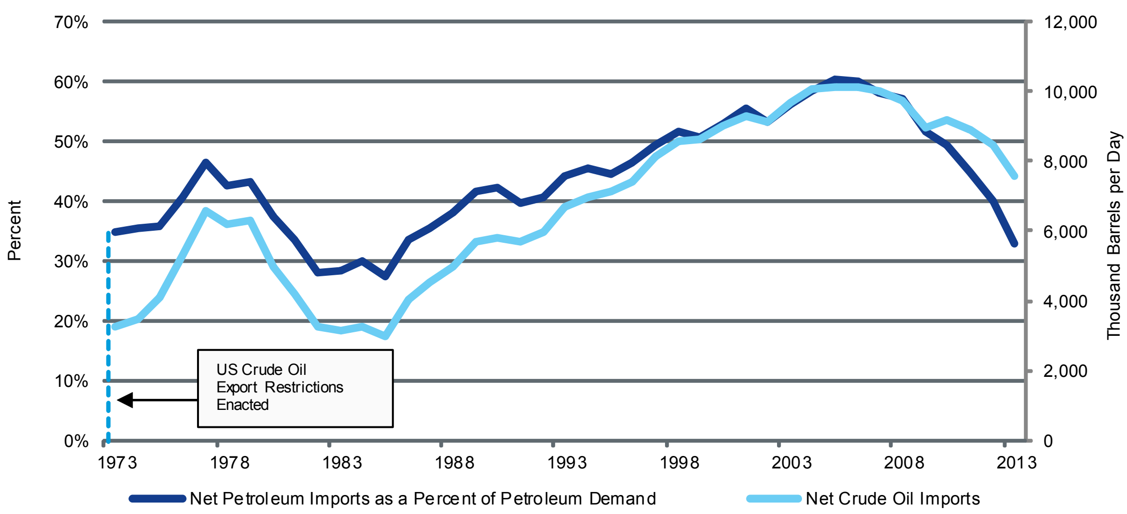
POLICY BENEFITS

No matter the rationale of the 1970s policy prohibiting exports, there is scant evidence that crude export policy had much of an impact on US oil import reliance. In the years following the 1975 legislation, US oil imports have remained above 3 million B/D, fluctuating in response to domestic production, economic activity, and energy efficiency (Figure 1.1). The reduction in demand and imports during the early 1980s was related to a major recession, a shifting from residual fuel oil (RFO) to gas in the power sector, the impact of automobile fuel efficiency standards and (in the case of imports) the build-up of new supply from Alaska. But that was a temporary downturn. Between 1975 and 2005, net imports overall rose from 36% to 60% of total demand.

Since 2005, a steep fall has been registered in US import dependence—from that 60% down to 29% in March 2014. The reasons are multiple, including the drop in product demand from the Great Recession, the increase in domestic crude production from LTO and the increase in vehicle fuel efficiency. This dependence can be expected to fall further over the coming years as oil production increases and consumption remains relatively stable or declines.

[19] Bureau of Industry and Security, U.S. Department of Commerce, Short Supply Controls, https://www.bis.doc.gov/index.php/forms-documents/doc_view/425-part-754-short-supply-controls.
[20] Vann, Adam, Congressional Research Service "Applicability of Federal Export Requirements to Natural Gas Liquids and Condensate" http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=3e18847c-cf43-48f6-ad3a-f8f896a5cc5c.
[21] Schlumberger Oilfield Glossary, available at http://www.glossary.oilfield.slb.com/en/Terms/c/condensate.aspx.
[22] http://www.eia.gov/conference/ngl_virtual/eia-ngl_workshop-anne-keller.pdf.

FIGURE 1.1
US Petroleum (Crude Oil and Refined Product) Import Dependence



IHS Energy, EIA

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KEY QUESTIONS ADDRESSED

Many important questions need to be addressed in reviewing oil export policy. This study responds to these important issues.

WHAT VALUE DOES THE CURRENT POLICY PROVIDE?

Until recently, current policy essentially had no effect, because there was insufficient crude production to allow exports to occur on an economic basis—the United States was a substantial light crude importer. But over the past three years, the United States has reduced its light crude imports from 2.7 million B/D to 0.7 million B/D. Now, the ban is starting to distort markets, as US Gulf Coast crudes have become disconnected from global markets at a price below international crude, even as gasoline and other refined US products remain tied to global prices. This disconnect reduces investment in the US oil sector, job creation and energy security.

WHAT ABOUT GASOLINE PRICES?

A central fear of permitting crude oil exports is that gasoline prices will increase as the Gridlock is cleared and domestic crude oil prices increase to international levels. The historical record on this point clearly contradicts this notion. US gasoline prices are most directly related to international gasoline prices due to free trade (both imports and exports) with Europe and other world markets. Rapid and large changes in the domestic pricing at Cushing, Oklahoma, for crude oil beginning in 2011 and in US Gulf Coast crude in late 2013 have had little, if any, influence on gasoline prices, nationally or in those regions.[23] Therefore, a domestic crude price increase associated with the free trade of crude oil is not likely to affect the US gasoline price.

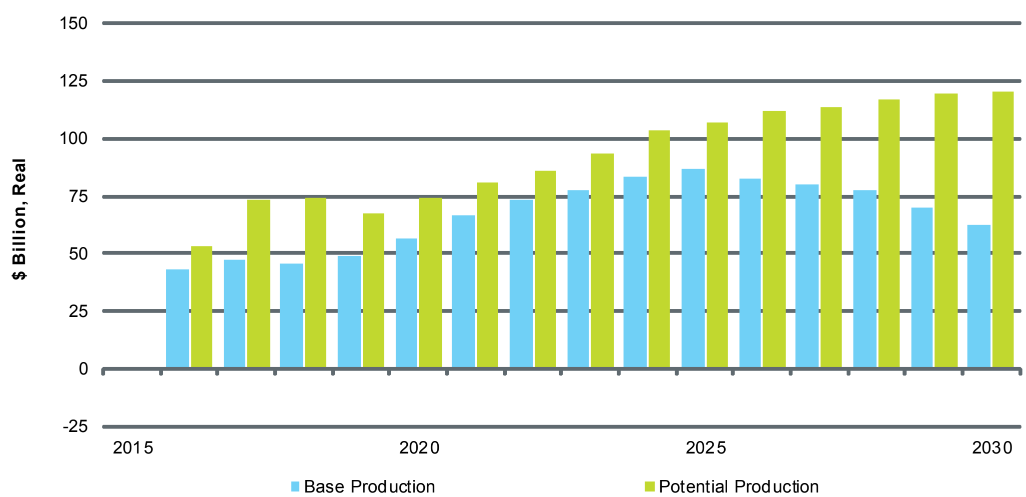
The US gasoline price is instead affected by international crude prices (e.g., Brent crude oil), transmitted through global gasoline prices. In a better-supplied world oil market (which would result from exporting US crude), prices would be lower than in a tighter market. Those lower prices would flow back into US gasoline prices.

[23] Cushing, Oklahoma, is a primary US crude oil pricing location and the basis of physical delivery for New York Mercantile Exchange contracts.

WHAT ARE THE BENEFITS OF INCREASED PRODUCTION OF DOMESTIC CRUDE OIL?

Domestic crude production adds significant value in terms of investment, jobs and economic activity, and also increases energy security, among other benefits. Further, because US oil demand is little affected, increased production directly reduces our petroleum import bill. The Great Revival has already resulted in substantial improvements to the long standing petroleum trade deficit. IHS calculates that the US petroleum import bill stood at $311 billion in 2011 and by 2013 had been reduced by 30% to $218 billion.[24] Free trade will further reduce the import bill by $67 billion per year compared to the current restricted trade policy.

FIGURE 1.2
Reduction in US Net Petroleum Import Bill from Free Trade



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WHAT IS THE REASON FOR EXPORTING CRUDE OIL WHEN THE UNITED STATES STILL IMPORTS A SIGNIFICANT VOLUME OF CRUDE?

This important question focuses in on the character of the US refining system and, in particular, US Gulf Coast refineries, which constitute more than half the total refining capacity of the United States. Some $85 billion dollars has been invested to upgrade Gulf Coast refineries to process large volumes of heavy crude oil. They cannot efficiently process large volumes of light crude. As a result, light crude is in Gridlock, while heavy crudes remain on an open highway. Because the heavy crude refineries are inefficient at processing light crude, a substantial light crude price discount is required to recover the economic penalty of substituting domestic light crude for imported heavy crude.

WHAT IS THE DIFFERENCE BETWEEN "GROSS IMPORTS" AND "NET IMPORTS"?

This distinction holds great importance for export policy. Gross imports measures the total oil imported into the United States. Net imports subtracts exports of refined products and crude from gross imports. In 2013, for instance, gross imports were 9.8 million B/D, while exports were 3.6 million B/D (mostly refined products). The resulting net imports were 6.2 million B/D.

[24] IHS calculation for the US net petroleum trade deficit is slightly different from the EIA Merchandise Trade Value statistics. The primary difference being EIA data is based on import/export customs data where IHS uses EIA imports and export volumes multiplied by applicable spot benchmark price quotations to provide consistency for forecasting purposes.

Net imports are the key indicator of import dependence. A barrel exported does not create a one barrel deficit, for that barrel will be replaced by a barrel imported. However, allowing the market to make that decision will enhance economic efficiency. Moreover, light crude is more valuable than heavy crude, so exporting surplus light oil improves the US trade balance and supports more economic activity in the United States, rather than constraining activity as is the case under the current policy. Increasing US exports, which also stimulates increased production over what it would otherwise be, will lower net imports.

STUDY APPROACH

This report provides an in-depth review of the refining industry and the macroeconomic implications and impacts of moving from the current restricted trade policy to a free trade policy that allows crude to be freely exported (barring extreme cases, such as times of national emergency). The study addresses the key topics using an end-to-end analysis, beginning with upstream oil production through the downstream refining process, including pricing and investment implications, and concluding with the macroeconomic impacts (e.g., economic growth, jobs) at the national and state levels.

IHS brings a wide range of capabilities to bear through its integrated team and modeling systems. Its understanding of upstream production and downstream refining are combined with in-depth macroeconomic skills, bolstered by the largest well database of upstream US oil and gas, and extensive refining and petroleum market databases and national and state economic databases. IHS builds on a steady flow of ongoing research and previous studies that have combined these capabilities, including on the economic impact of the unconventional revolution in shale gas and tight oil technologies.

The following provides an overview of the analytical approach and results provided in this report.

- Crude production is forecast for two different cases: Base Production and Potential Production. The production is first forecasted assuming a free trade environment that allows international market trading and pricing. For each production case, a restricted trade policy is also assessed using a domestic crude price discount provided by the refining market analysis and reflecting Gridlock (an oversupply) in the light crude oil market. These restricted trade evaluations result in decreased crude oil prices, which translate to less investment and lower crude oil production.
- An analysis of downstream refining capacity provides an estimate of light crude processing capacity and examines in detail the important US Gulf Coast refining market. With all of the light crude processing capacity already filled in the Gulf Coast, refiners are now substituting light crude (also known as light tight oil, or LTO) for sour crude (medium sour and heavy sour) refining capacity. An analysis of the available tiers in sour crude processing is quantified to estimate the forthcoming LTO price discounts associated with a Gridlocked market and inefficient light crude processing in the Gulf Coast refining system.
- Pricing analysis for international crude oil and US gasoline provides the free trade benefit when crude exports affect international prices.
- Finally, the US macroeconomic impact is modeled from changes in industry investment, production, national trade flows, crude and gasoline pricing and other inputs. National and state-level results are provided for both production cases.

II. US CRUDE OIL PRODUCTION ANALYSIS

KEY INSIGHTS

- The potential for increasing US oil production is much greater than previously anticipated, but to be fully realized will require the ability to export crude oil—in particular, light tight oil (LTO) streams that exceed the capacity of the US refining system.
- Our Base Production Case with exports allowed envisages LTO production peaking at 6.1 million B/D in 2024, up from 2.8 million B/D in 2013. In this case, total US crude oil output is expected to rise from 7.4 million B/D in 2013 to 11.2 million B/D in 2022.
- In the Potential Production Case, IHS estimates the output of LTO under favorable conditions, which include the ability to export, has the potential to peak at 9.2 million B/D in 2028, resulting in total US peak oil output of 14.3 million B/D.
- If crude oil exports continue to be restricted, US oil output is expected to be 1.2 million B/D lower in the Base Production Case and 2.3 million B/D lower in the Potential Production Case. That is because US refining capacity for light sweet crude—sometimes known as low-sulfur crude that is produced in unconventional tight oil plays—is limited.
- Rapid production growth and continued expansion of output is driven by a number of factors, but one key driver has been the ability of producers to quickly implement new learnings developed in the industry. The result is improved drilling and production performance, more potential drilling locations, additional economic reservoirs, increased recovery rates and operational cost savings. These trends are expected to continue for the relatively young tight oil revival.
- Producers in search of higher value crude oil resources are focusing on liquid-rich unconventional tight oil plays such as Bakken, Niobrara, Eagle Ford and West Texas. All of these plays produce light sweet (low-sulfur) crude oil. As a result, light sweet crude oil production is increasing at a much faster rate and accounts for virtually all increases in forecast production.
- Price discounts to make refiners choose to process light oil instead of the heavy oils for which they are configured would make some tight plays uneconomic. Tight oil is a relatively high-cost resource, with some plays requiring a wellhead crude oil price of greater than $80 per barrel to fully recover development costs.
- Without the ability to export crude oil, price discounts between 2015 and 2018 are projected to be as much as $12-15 per barrel (compared to $3-5 per barrel today). The price discounts above reflect the price of domestic crude oil on the US Gulf Coast. However, many of the tight oil plays are located inland, and the price at the wellhead for these plays is lower—typically in the range of $4-12 per barrel—due to the logistics cost of transporting crude oil to refining centers. As a result, the wellhead price of Bakken crude oil in North Dakota is approximately $25 per barrel below its international equivalent during the 2015-2018 period.

THE GREAT REVIVAL

The upstream oil and gas industry in the United States has been revitalized by the emergence of unconventional "tight" oil resources. This has resulted in a substantial increase in US crude oil and total liquids production in the past half a dozen years.[25] Total US daily production of crude oil increased from 5 million B/D in 2008 to 7.4 million B/D in calendar year 2013 and 8.2 million B/D in March 2014. This remarkable growth trend in crude output has profound implications for US and global oil markets. One critical issue concerns the capacity of the US downstream oil refining industry to efficiently handle increasing domestic output of light crude oil. Crude oil exports are for the most part banned.

[25] Liquids include NGLs, condensate and crude oil.

The surge in US light oil supplies has already displaced similar quality imported light crude oil and is now testing refining capacity limits. Exports of crude oil under a free trade policy could resolve this issue, allowing oil producers to continue increasing their output without the wellhead discounts that are a disincentive to investment in increasing production capacity. Of key importance, it should be noted that wellhead price discounts do not translate into gasoline price discounts, as discussed in Section IV.

STUDY CASE DESCRIPTIONS

IHS has created two scenarios for the outlook for US oil production in the years ahead. We have named them the Base Production Case and the Potential Production Case. These outlooks are based on the following: analyzing proprietary IHS databases and public data; utilizing proprietary forecast models and methodologies and incorporating the perspectives and analyses of internal and external oil industry experts. In a further refinement, IHS has studied the outcome of each case based on whether the United States lifts the effective ban on crude exports or continues with it.

FIGURE 2.1
Basis for Production Cases and Trade Policies

Production Cases

Trade Policies	**Base** IHS central planning forecast. Conservative view based on defined plays and assumes limited industry improvements.	**Potential** Includes additional potential but less w ell defined areas of existing plays, moderate industry drilling and technology improvements.
Restricted Current policies (including condensate treatment as crude).	Base Production / Restricted Trade	Potential Production / Restricted Trade
Free Trade to broad group of trading partners including Europe and Asia (India, China).	Base Production / Free Trade	Potential Production / Free Trade

Trade Policy Decision

Difference in Underlying US Production Forecast View

Note: Each case starts with the same IHS macroeconomic and international crude oil price f orecast

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After analyzing these cases, we conclude the following:

- The growth in US crude oil production will come mainly from higher-cost unconventional resources, the development of which is predicated on the price levels of the last few years' and the continued application of technology and innovation.
- Oil production growth will come primarily from the Bakken, Eagle Ford and Permian Basin areas, which produce a LTO or light sweet crude grade. This will result in increases in the volume of light oil in excess of the ability of US refineries to process it.
- Oil prices will be a primary driver of investment to increase production. Any actual or anticipated reduction in US crude prices because of export restrictions will prompt producers to reduce drilling in higher cost unconventional plays, resulting in lower production rates for LTO.

- Forecasts have typically underestimated the growth of unconventional oil production. A main reason is the challenge of anticipating the speed of the industry's ability to apply new technology and innovation to continuously improve performance and lower costs. One of the prime reasons for the difficulty in assessing the pace and impact of innovation is the variegated and competitive nature of the US upstream industry, in which much of the exploration and about 85% of production is carried out by a wide range of independent producing companies. Also not anticipated has been the ability of producers and midstream companies to overcome a lack of infrastructure in transporting crude oil to refineries.
- With this recent experience in mind, IHS has developed the Potential Production Case that assumes that industry will be able to commercially produce additional resources that are just now being identified with most of these being located in established tight oil plays and a higher pace of technology and drilling efficiency improvements.

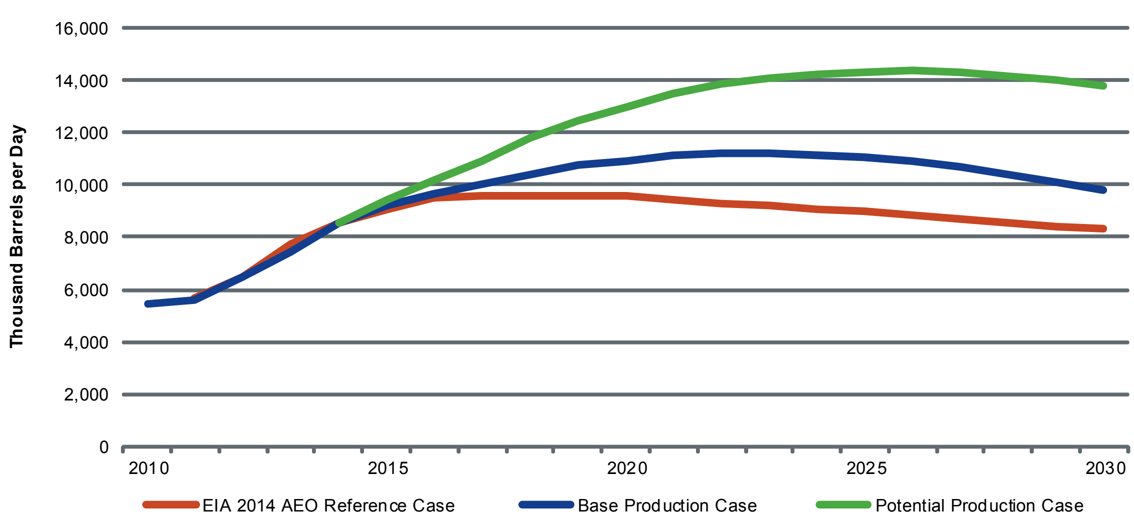
OIL PRODUCTION FORECASTS: BASE PRODUCTION CASE AND POTENTIAL PRODUCTION CASE

Oil production is projected to rise significantly in the years ahead, but outcomes vary based on a multitude of factors. The first part of this section presents the Base Production Case and a Potential Production Case—both of which are based on a free trade policy under which exports are allowed. Later in this chapter, these crude production cases are assessed under a restricted trade policy under which exports continue to be essentially banned.

THE OUTLOOK FOR PRODUCTION INCREASES

The US government's Energy Information Administration (US EIA) currently estimates crude oil output will peak at 9.6 million B/D in 2019 (compared to an April 2011 forecast of 5.9 million B/D) before production begins to decline (Figure 2.2).[26] [27]

FIGURE 2.2
IHS Oil Production Forecasts Compared to EIA Annual Energy Outlook (AEO) Forecast



Source: IHS Energy, EIA

Note: EIA 2014 AEO released April 7, 2014

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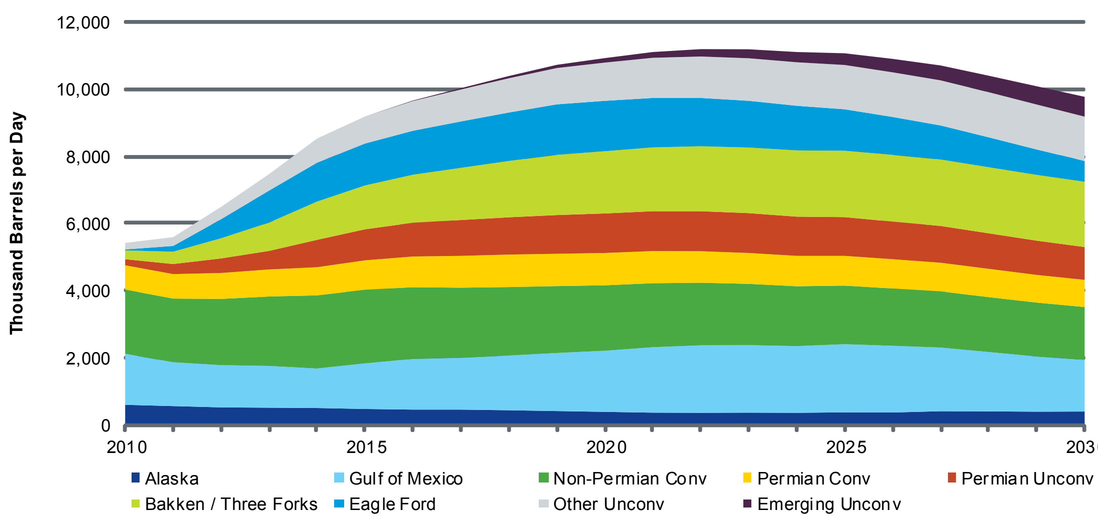
[26] EIA Annual Energy Outlook, April 2011, Reference Case.
[27] EIA Annual Energy Outlook, April 2014, Early Release, Reference Case.

However, our analysis, based on geology and production technologies, evolving oil plays and our database of producing wells in the United States, suggest a different profile with a significantly higher peak output. The reasons are 1) improved performance at the well level; 2) an extensive inventory of drilling locations that are available from known defined and delineated reserves and contingent and perspective resources, particularly in tight oil or other unconventional oil plays and 3) enhancements in producing technologies and the application of innovative operating practices.

The IHS Base Production Case projects production increases through 2022 when production peaks at 11.2 million B/D. The IHS Potential Production Case indicates a much higher output peak of 14.3 million B/D in 2026 with production declining only slightly by 2030.

IHS outlooks are the result of a fundamental bottom-up analysis that begins with each contributing geologic play. These play-level forecasts were aggregated to develop the total US crude production forecasts. Nine major contributing plays, shown in below, represent conventional onshore and offshore plays, as well as unconventional plays. Numerous sub-plays exist within each of these nine plays, all of which were aggregated to this level for ease of presentation.

FIGURE 2.3
Base Production Case: US Production Forecast by Play



Source: IHS Energy © 2014 IHS

POTENTIAL PRODUCTION CASE FORECAST

The Base Production Case reflects:

- Known plays that have been defined and delineated by available geologic information, engineering data and production history.
- Historical and current production and production trends from each play.
- Application of known practices and technologies used to extract resources from these plays.

The history of major unconventional plays has shown that significant learning curves for both production rates and costs are inherent in the application of technology, which typically leads to development upside. Thus, some upside potential is included in the Base Production Case. The Potential Production Case is intended to convey a less conservative view of each play and includes additional upside potential, as well as slightly elevated near term production performance. Both the Potential Production Case and the Base Production Case employ the same price forecast assumptions provided in Section IV.

CRUDE FORECASTING METHODOLOGY

For the unconventional crude oil production forecast, IHS used proprietary models that incorporate a fundamental bottom-up approach.* The methodology includes the following parameters for each play:

- Number of drilling locations: The geographic size of the play, with risking for different production boundaries within each play, downspacing and the number of production zones.
- Type curve: The purpose of type curves is to create an expected or average production profile that will be replicated for the forecasted wells. Type curves are developed based on recent well performance data and known trends within the play, such as down-spacing.
- Drill rig count and drilling cycle times: Historic rig counts and well completions are tracked by play and forecasted based on the maturity of the play, known drill plans and total industry drilling activity. Rig cycle times reflect the average number of drill days and are forecasted based on actual performance with conservative improvements in drilling efficiency.

The methodology used here to assess the impact of restricted trade impact included drilling activity reduction (less wells drilled) due to lower wellhead prices. As prices decline, some areas of tight oil plays become uneconomic. IHS maintains a detailed play-level cost and economic model, which provides breakeven costs, which forms the basis for determining the level of drilling reduction in each tight oil play. This reduced drilling leads to lower production through the production model above.

* Play level capital cost, operating cost and production forecasting models similar to those used to generate content for the Vantage database. Type curve generation using PowerTools and Harmony proprietary software and IHS well and production databases.

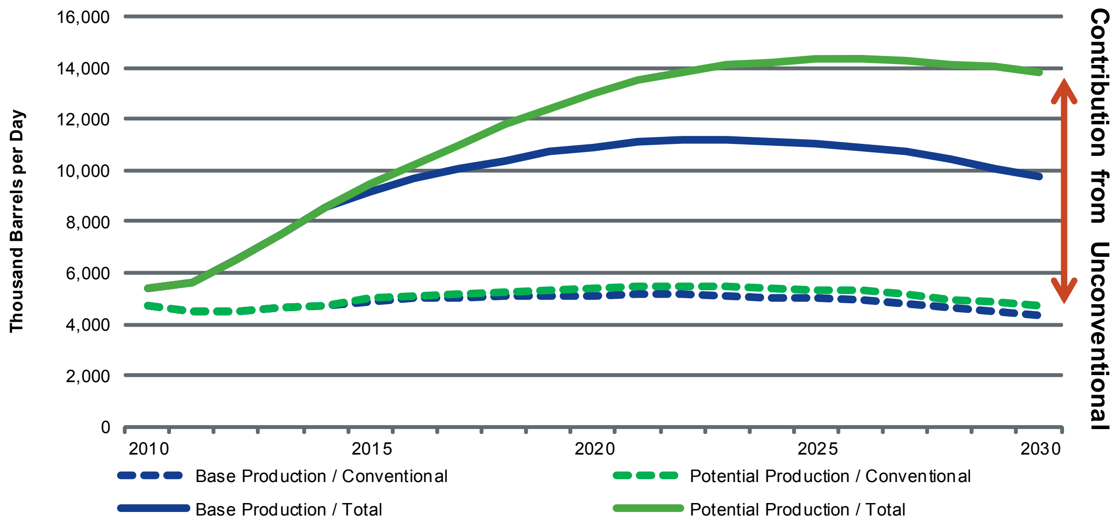
UNCONVENTIONAL "LIGHT TIGHT OIL" IMPACT

Almost all of the growth in output is expected to come from increased oil production from unconventional reservoirs, commonly referred to as LTO (Figure 2.4).[28] IHS expects LTO production to peak at 6.1 million B/D in 2024 and 9.2 million B/D in 2028 for the Base and Potential Production Cases, respectively. The second largest contribution to crude oil production growth comes from the Gulf of Mexico (GOM), with forecast production peaking at 2 million B/D in 2023 and 2.2 million B/D in 2025 in the Base and Potential Production Cases, respectively.

Given the rapid developments and relatively limited historical LTO production data, unconventional play development carries a relatively high range of uncertainty. Key variables include the amount of commercial resources available, future well performance, the timing of development, takeaway capacity (transportation capacity from the field), commodity prices and the manner in which current and future technology and innovation will be applied. Due to this uncertainty, virtually all of the difference between the Base Production Case and the Potential Production Case is attributed to unconventional oil production (Figure 2.4).

[28] The term tight oil is specific to crude oil extracted from low-porosity geologic formations which cannot be produced commercially under natural conditions. Economic development of the resource is facilitated by the combination of hydraulic fracturing and horizontal drilling.

FIGURE 2.4
Unconventional Contributions to Base and Potential Production Forecasts



Source: IHS Energy

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Within several of these tight oil plays, producers have identified very large quantities of oil-in-place.[29] However, at this time, recovery rates are very low. Even the Potential Production Case projects that a relatively small percentage of oil-in-place will be recovered before 2030 with known technology. This reflects a further degree of forecasting conservatism for both production forecasts. The following five play categories are included in forecasts of the four cases outlined above (detailed play discussions are provided in Appendix C):

- Bakken / Three Forks.
- Eagle Ford.
- Permian Basin Unconventional.
- Other unconventional mid-level plays beyond the first three major plays listed above.
- Emerging or potential plays.

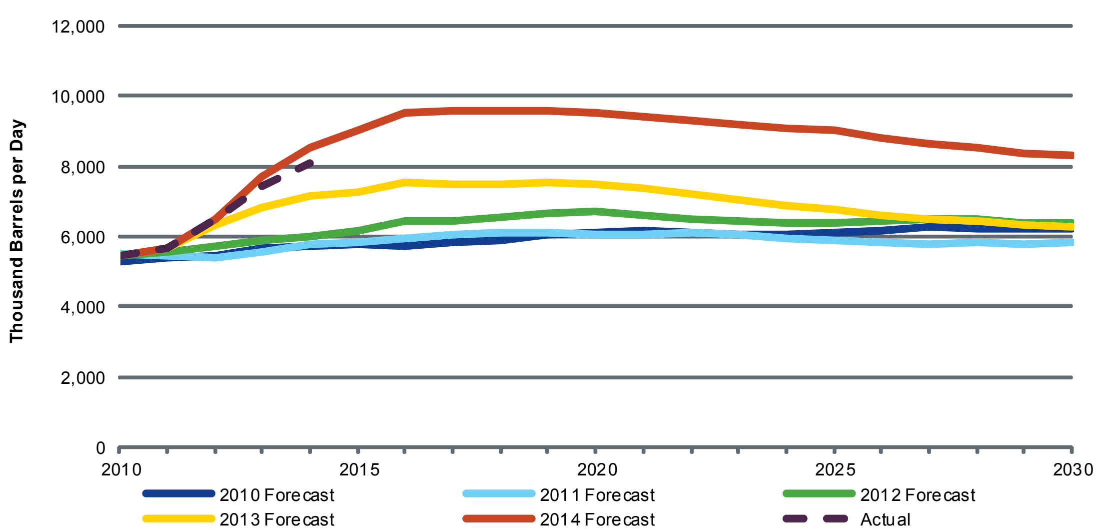
REVIEW OF HISTORICAL FORECASTS

Prior to about 2008, the tight oil revival was not forecasted to occur, and forecasts conducted since then have generally under-predicted actual output from unconventional plays. Once operators "crack the code" and determine how to successfully produce in large plays such as the Bakken / Three Forks, production ramps up very quickly and producers are able to generate much larger production growth than was initially projected. As an example, the forecasts from the EIA Annual Energy Outlook (AEO) for five consecutive years show a common evolution for tight oil forecasts over the past three to five years (Figure 2.5). The pace of growth is illustrated by the fact that production by September 2013 exceeded that year's AEO forecast for peak production of 7.5 million B/D in year 2016.

Similarly, forecast volumes for the Eagle Ford have been surpassed by actual output in each year the forecast was published. (Figure 2.6)

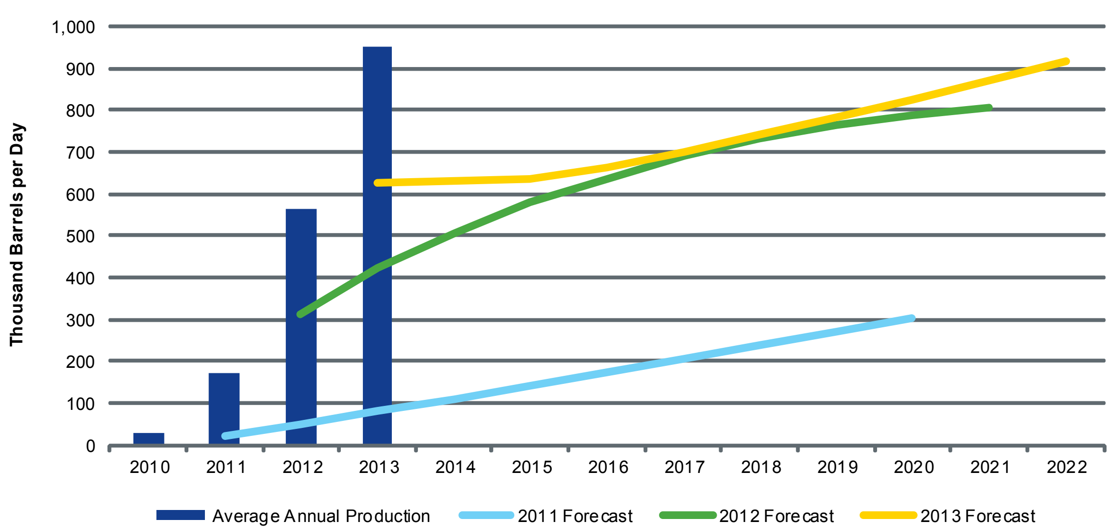
[29] Oil-in-place refers to the total hydrocarbon content of an oil reservoir and is not to be confused with an oil reserve, which is an estimate of the economically recoverable portion of a reservoir.

FIGURE 2.5
US EIA Annual Energy Outlook (AEO) Domestic Crude Production Forecasts (2010-2014)



Source: EIA Note: EIA Reference Case © 2014 IHS

FIGURE 2.6
Comparison of University of Texas - San Antonio Eagle Ford Forecasts



Source: IHS Energy, University of Texas - San Antonio © 2014 IHS

PRODUCTION INCREASE FACTORS

A key driver of this rapid production growth is that producers generally work within a culture of continuous improvement aimed at increasing performance, reducing costs and building an ever-larger portfolio of drilling locations. The following are some examples:

- **Performance Improvement:** Operators are seeking to improve drilling performance by utilizing longer laterals (by extending wellbore pipe horizontally through reservoirs), improving the effectiveness of hydraulic fracturing and more accurately locating the position of the horizontal borehole within a specified target zone. These techniques enable operators to target "sweet spots" of specific formations and sub-plays where deposits are particularly prolific. For instance, wells drilled after 2011 have substantially better performance than wells drilled just a few years before. More recent performance data suggest that another step change in performance improvement occurred in some plays in late 2013.

- **Additional Reservoirs:** Within established plays, new producing reservoirs have been identified. These new reservoirs could double or even triple the amount of commercially recoverable oil. Examples include up to three additional zones in the Three Forks, multiple zones in the Permian Wolfcamp and three potential zones in the Niobrara.
- **Optimum Spacing:** Operators are currently optimizing well spacing and associated completion practices for unconventional plays.[30] Traditional well spacing in some of the more mature shale plays has evolved to 80-acre spacing (660 feet between laterals), but operators are evaluating tighter downspacing in core areas of the most prolific plays.[31] [32] Tighter downspacing will increase overall oil recovery rates, but may also reduce per-well output; thus operators seek the economic optimum.
- **Operational Best Practices:** Operators are continually working to improve efficiency and cut costs by reducing drill times (the number of days required for a rig to drill a well), by employing the practice of “batch” drilling (drilling multiple wells from a single drill pad location) and by optimizing hydraulic fracture operations to increase oil flow. The net effect of these efforts is to reduce drill cycle times, bringing more production online at a faster rate.

The results of these improvement initiatives are highlighted in investor presentations and Securities and Exchange Commission filings by producers. Furthermore, knowledge gained through successes and breakthroughs are shared among producers, service companies, professional societies and universities so that the entire producer community within a play benefits.

Our Base Production Case and Potential Production Case forecasts seek to balance historical performance with our data analysis, known and proven current performance and anticipated benefits from technology advances. A detailed discussion of IHS’ methodology and assumptions is contained in Appendix B.

OUTLOOK BEYOND 2030

The production outlooks in this study extend to 2030, but it is instructive to consider the total production from tight oil resources beyond this period. Oil production for the two cases is provided through 2050 in Table 2.1. The 93.7 billion barrel forecast from 2014 through 2050 in the Potential Production Case is nearly 50% higher than the 61.6 billion barrels in the Base Production Case. The US Geological Survey is in the process of reevaluating its current estimate US crude oil reserves of 33.4 billion barrels—a further illustration of the pace of change for tight oil.

TABLE 2.1
Unconventional Commercial Resource: Resource in the Free Trade Environment

	Oil - Million barrels		Number of Wells	
	2014-2030	2014-2050	2014-2030	2014-2050
Base Production Case	33,305	61,600	217,217	353,595
Potential Production Case	46,462	93,695	266,152	438,269

Source: IHS Energy

[30] Well spacing refers to the number of acres a horizontal lateral occupies.
[31] A lateral refers to a horizontally drilled section of a given well.
[32] Downspacing refers to a reduction in the distance between horizontal laterals and tighter downspacing adds more wells per a geographic area.

There is, of course, a measure of uncertainty associated with assessing the impact over the next 36 years of performance improvement and cost reduction due to improved technology or innovation. However, the industry's track record and the focus on technology and best practices suggest that performance will continue to improve. It is, for instance, quite possible that today's Potential Case may be tomorrow's Base Case.

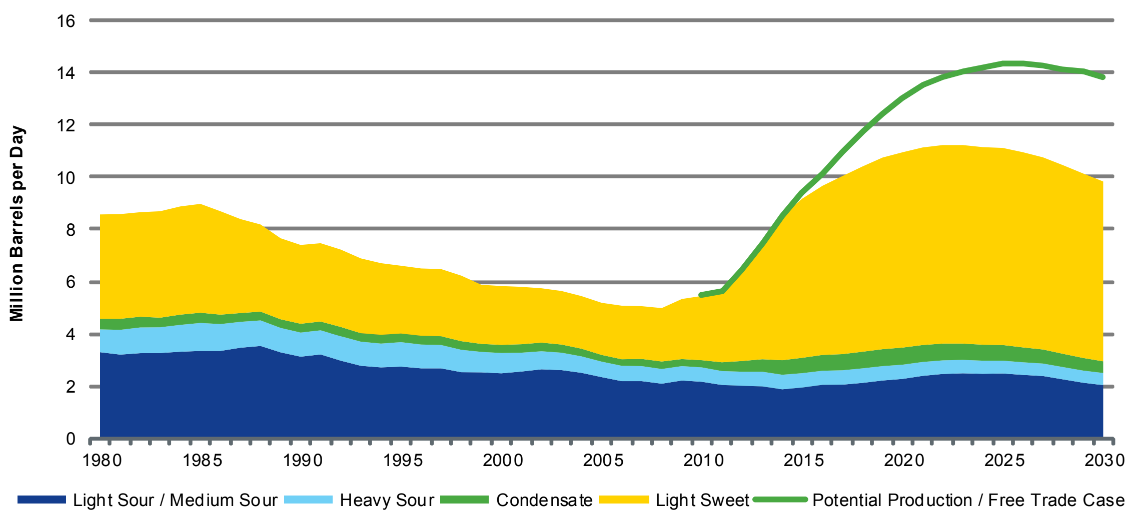
OTHER FORECAST CONSIDERATIONS

This discussion has so far addressed geologic, engineering and technical matters with finding, developing and producing crude oil. In the next few pages, the above-ground factors embedded into our forecasts will be discussed.

LIGHT OIL GROWTH

As presented in the next two sections, it is not only the rapid production increases in crude oil but also the light quality of LTO that are impacting the refining industry and LTO prices. Producers in search of higher-value crude oil resources are focusing their efforts on liquid-rich unconventional tight oil plays such as the Bakken, Niobrara, Eagle Ford and West Texas. These plays produce LTO and, as a result, light sweet crude oil production is increasing at a much faster rate than other crude quality types. LTO accounts for virtually all increases in forecast production, with increases in light and medium sour grades in the Gulf of Mexico largely offset by declines in other conventional sour production elsewhere (Figure 2.7). This represents a major shift from the historic mix of crude types produced in the United States.

FIGURE 2.7
US Crude Production by Crude Type



Source: IHS Energy, EIA

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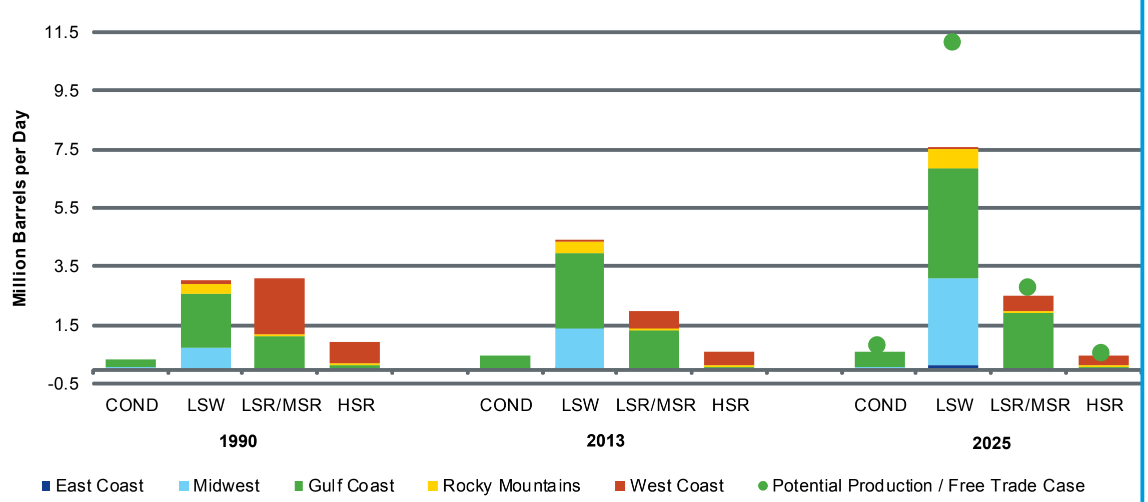
Along with tight oil increases, production trends by US region and quality type are changing, with most production expected in the Midwest and Texas and most of this coming in the form of LTO.

While the United States produced 7.4 million B/D of crude oil in 2013, equaling the volume produced in 1990, the primary changes in regional production and quality for each region since this period and for our 2025 forecast have changed and include (See Figure 2.8):

- **East Coast:** This region produced little crude in 1990 but moderate increases in LTO production are expected with the development of the Utica play.

- **Midwest:** This region has rapidly growing production due largely to the Bakken and nearly all production will be LTO.
- **Gulf Coast:** This region includes Texas and the Gulf of Mexico, so it has a mix of light / medium sour and light sweet production. Most of the growth in Texas will be in LTO from Eagle Ford and the Permian unconventional plays, and most of the Gulf of Mexico growth will be in sour crude grades from deepwater developments.
- **Rocky Mountains:** Production of LTO will grow but remain relatively small.
- **West Coast and Alaska:** This region accounted for over 35% of US production in 1990, but declines in Californian heavy sour and Alaskan light sour crude grades (1.7 million B/D since 1990) have reduced the region's contribution to less than 10%.

FIGURE 2.8
Evolution of US Crude Quality by Region (as Marketed)



Source: IHS Energy, EIA Note: COND = Condensate, LSW = Light Sweet, LSR/MSR = Light Sour/Medium Sour, HSR = Heavy Sour © 2014 IHS

CONSIDERATION OF ABOVEGROUND FACTORS

The Base and Potential Production Cases are predicated on applying geologic, engineering and technical parameters to the continuous or unimpeded development of these resources in a roughly $100 per barrel price environment without commercial constraints. These commercial constraints, often categorized as "aboveground" factors, could potentially slow development and delay or stunt forecasted production. Among the aboveground factors that could affect production are the price of oil, the availability of rigs and oilfield services, costs, infrastructure and environmental concerns.

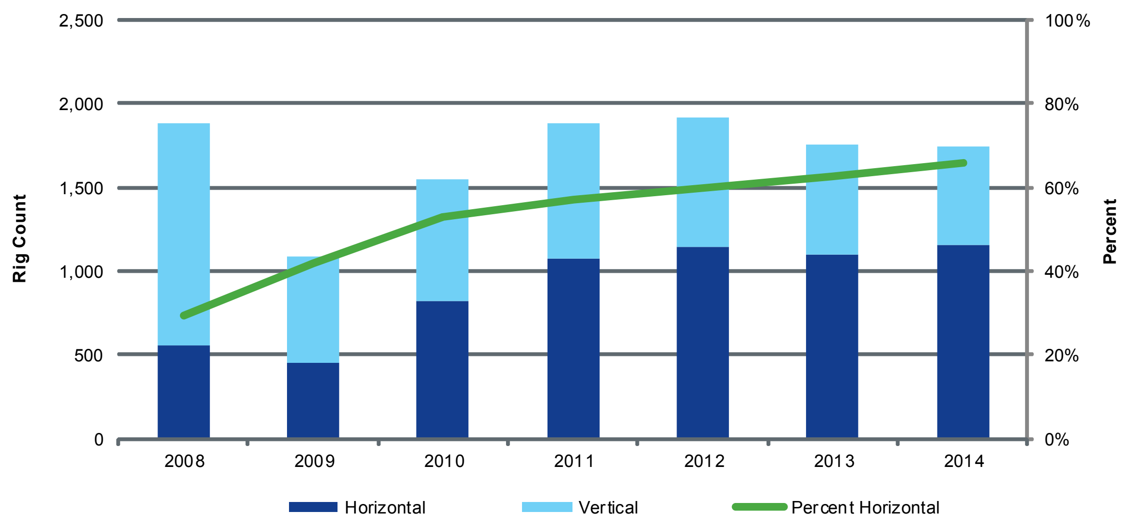
PRICE

The price of oil and the expected trajectory of future oil prices are key determinants of investment in oil production. Because unconventional oil is typically at the high end of the industry's cost curve, unconventional plays are particularly sensitive to price expectations. For the past three years, the benchmark Brent oil price has stayed above $100 per barrel, and IHS forecasts prices to remain in this range or higher through 2030 (real dollar basis). The price for US West Texas Intermediate crude will decline to approximately $86 per barrel in 2015, as oversupply depresses light crude prices, but will then recover to near $100 per barrel in 2016 (with free trade) and will remain at or above this level through 2030. Results in both the Base Production Case and the Potential Production Case are contingent upon prices staying within this forecast range.

RIGS AND OILFIELD SERVICE AVAILABILITY

A shortage of rigs in the years ahead is not foreseen. The number of new US oil wells has increased, reaching a peak of 29,650 wells in 2012, up from 19,500 in 2010. The percentage of horizontal wells is expected to increase (over the forecast period 2016-2030), with nearly two-thirds of active rigs currently designated as horizontal. The number of horizontal rigs increased from 822 in 2010 to 1,150 in 2012. The rig count has been relatively flat since then (Figure 2.9). The number of new oil wells is expected to decrease slightly in the Base Production Case and increase only modestly in the Potential Production Case. Moreover, increased drilling efficiencies are likely to reduce the number of rigs needed to achieve forecast production levels.

FIGURE 2.9
Historical Rigs Counts by Type



Source: IHS Energy

Drilling needs over the forecast period are expected to be either flat or only modestly higher. Oilfield service providers should thus be able to meet the industry's needs.

INFRASTRUCTURE

Most major plays that have either experienced or are expected to experience significant growth in the near future are located in a mature oil producing regions that has been a major source of conventional hydrocarbons for decades. Consequently, with the exception of Bakken, moderate to high levels of regional infrastructure such as pipelines and processing facilities were already in place. Over the past three years the midstream industry, in response to huge year-over-year production increases in plays such as Bakken and Eagle Ford, has developed infrastructure or alternatives, such as rail, to handle the increased supply. While production increases are still projected for these areas, the rate of growth is expected to slow and new projects are progressing to handle these expected increases (Table 2.2). While some local delays in terms of new output could occur as roads, bridges and pipelines are built in response to projected production increases, overall long term growth will not be impeded as the United States has a highly skilled and flexible service industry that can be mobilized and scaled up quickly as plays increase production.

The current and projected takeaway capacity in the Bakken and Permian Basin is more than sufficient to handle anticipated production increases.[33]

TABLE 2.2
Production Growth by Play
(percent over period)

Play	2011-2013	2014-2016
Permian Unconventional	46	29
Other Unconventional	36	24
Bakken	48	23
Eagle Ford	280	14
Offshore Gulf of Mexico	-6	9

Source: IHS Energy

Pipeline takeaway capacity in the Bakken area has grown from 340,000 B/D in 2010 to 580,000 B/D in 2013. This is short of 2013's production of nearly 850,000 B/D, so producers are using rail to move volumes that cannot be transported via pipelines. Although rail is more expensive, it opens up additional refining markets (primarily on the US East Coast) and also provides flexibility and speed in delivering supplies. By 2016, pipeline takeaway capacity for the Bakken is expected to exceed 1.0 million B/D with ample rail takeaway capacity to meet production needs.

TABLE 2.3
Production versus Takeaway Capacity
(million barrels per day)

	2013	2016
Bakken Takeaway Capacity	**1.5**	**2.5**
Rail Takeaway	1.0	1.4
Pipeline Takeaway	0.6	1.2
Bakken Production: Potential Case	**0.8**	**1.5**
Permian Basin Takeaway Capacity	**1.7**	**2.7**
Local Refining	0.6	0.6
Pipeline Takeaway	1.1	2.0
Permian Basin Production: Potential Case	**1.4**	**2.1**

Note: Sum totals do not equal individual components due to rounding
Source: IHS Energy

Midstream projects in shale plays have attracted significant investments. For example, in the Eagle Ford play alone over 20 pipeline or midstream projects valued at over $3.5 billion have changed hands since June 2010 when production from the play began to increase significantly. Substantial midstream asset transactions have also taken place in other tight oil plays as these opportunities have attracted investors seeking long term cashflows and stable returns on investment.

While some drilling and production delays may occur, IHS has observed that the US midstream industry responds quickly to opportunities that fast-growing plays provide and that takeaway capacity quickly catches up with production needs. Consequently, infrastructure requirements are not considered to be a constraining factor in either Base Production or Potential Production cases as any delays in forecasted production will be relatively short (one to two years).

[33] "Takeaway capacity" is the capacity to transport crude oil away from a given production region via pipeline, rail, truck, barge or marine tanker.

ENVIRONMENTAL CONCERNS

Most of the growth in production is expected in Texas, North Dakota, Colorado and Oklahoma—all states with long histories of crude oil production and an extensive understanding of the industry and associated regulatory and environmental requirements. These states are developing new standards to meet environmental aspects of unconventional production. Hydraulic fracturing is also regulated by state agencies in each jurisdiction. Areas of possible concern that could slow development of resources include a shift in the weight of regulatory authority from states to the federal government, opposition by environmental organizations, local controversy, delays in reducing natural gas flaring in regions still developing infrastructure, water access, water disposal and uncertainty regarding emissions controls.

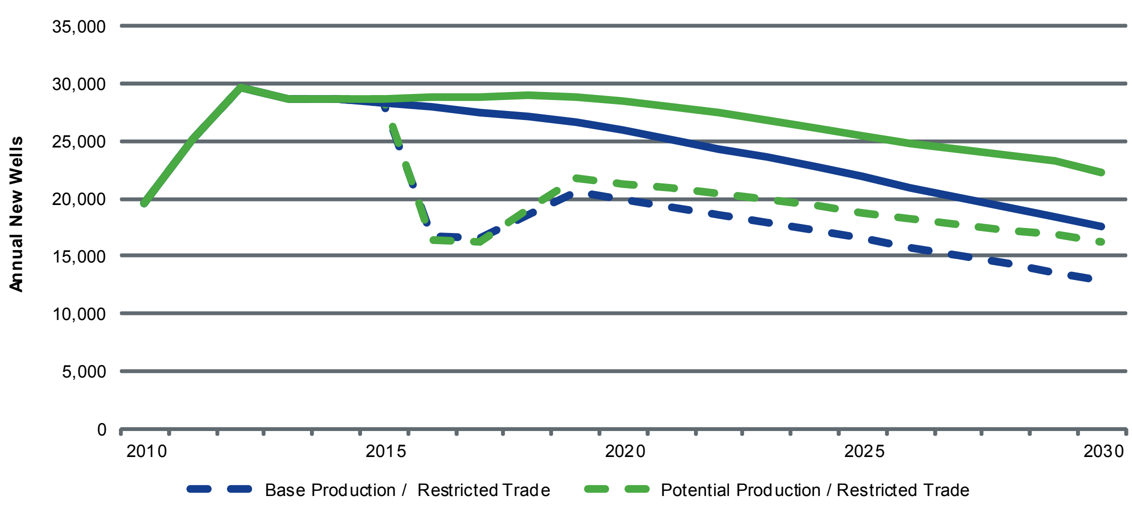
RESTRICTED TRADE POLICY

Up to this point, the assessment of the Base Production Case and Potential Production Case has been predicated on continuous or unimpeded development of resources in a roughly $100 per barrel price environment, and assuming the industry will be able to export oil that is in excess of domestic light crude refining capacity.

The US refining industry is reaching the limits of its ability to process the volumes of LTO being produced. Thus, the general ban on exports of crude oil is discounting LTO prices from where they would otherwise be, negatively impacting producers' revenues, cashflows and profits. The LTO price discount is presented in Section IV. That section will assess the impact of continued restrictions on exports under the Restricted Trade Cases.

Drilling activity reached a plateau of nearly 30,000 new oil wells per year in 2013. In the unconstrained free trade policy environment, the number of new wells is expected to remain between 25,000 and 30,000 through 2020 before tapering down to between 17,000 and 23,000 new wells by 2030 in the Base and Potential Production Cases, respectively. In contrast, we expect the number of wells to decrease more significantly (Figure 2.10) with restricted trade policies in place because of lower wellhead crude prices and reduced investment.

FIGURE 2.10
Impact of Restricted Trade Policies on Drilling Activity in Base and Potential Production Cases



Source: IHS Energy

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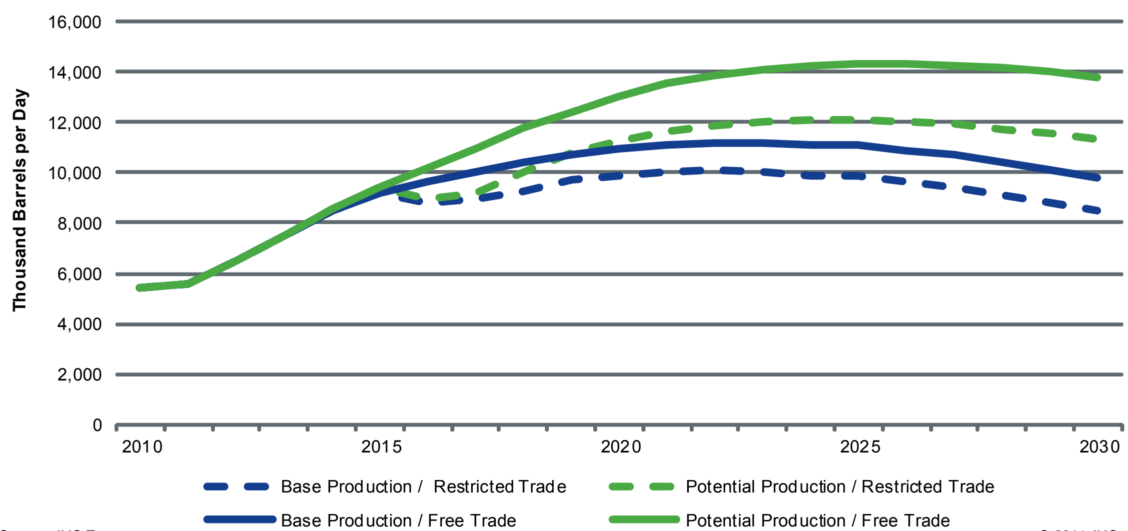
PRODUCTION RESPONSE

These reductions in drilling will limit further production increases (Figure 2.11). A decline in forecasted production is expected as early as 2016. The cumulative impact will be a projected loss of over 1 million B/D in the Base Production Case if trade continues to be restricted and a loss of over 2 million B/D in the Potential Production Case through most of the forecast period.

FIGURE 2.11
Impact of Trade Policies on Production



Source: IHS Energy

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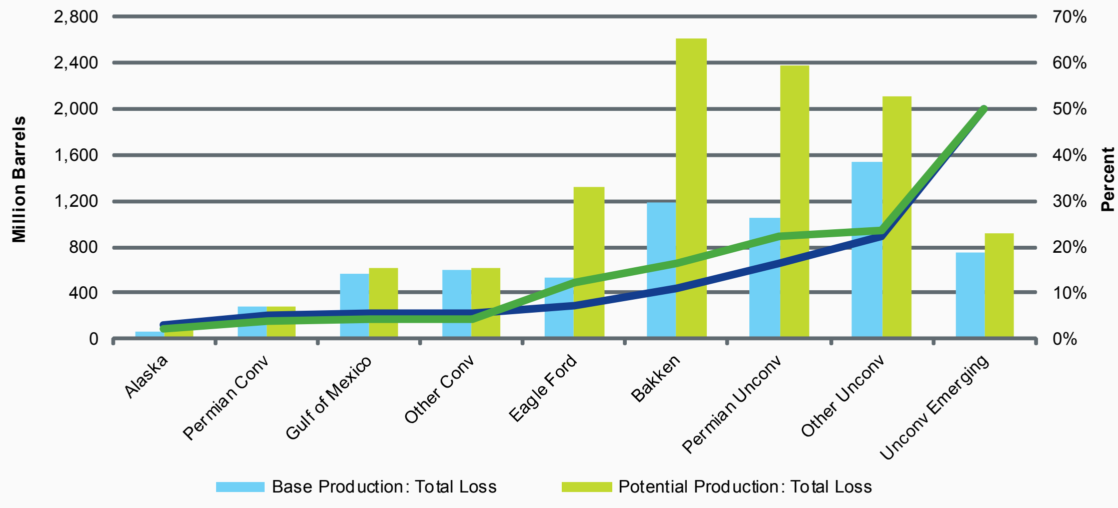
Figure 2.12 shows the estimated impact on crude production that will be felt by each play in the analysis if current restrictive trade policies remain. Losses from the unconventional plays will be felt most dramatically since a large percentage of these plays will not be developed within the forecast horizon of 2030. This loss of production will ultimately leave 6.6 billion barrels of oil in the ground in the Base Production Case and up to 10.9 billion barrels in the ground in the Potential Production Case. This is the estimated "opportunity cost" in terms of lost production from a continuation of the effective ban on crude oil exports.

The reason is to be found in terms of the interaction between the US oil industry's upstream and downstream activities—to be specific, in the nature of America's refining complex. It is to that subject that we now turn.

FIGURE 2.12
Resource Not Produced for Base and Potential Production Cases (2016-2030)



Source: IHS Energy

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III. US REFINING SYSTEM

KEY INSIGHTS

- The United States contains the largest and most sophisticated refining system in the world, with a total capacity of 18 million B/D distributed across 133 refineries. The scale and global competitiveness of the US refining industry stems from low-cost input energy from natural gas, the ability to process lower-quality, heavy crude oils into high-quality transportation fuels and a high degree of petrochemical integration.
- The centerpiece of the US refining system is the US Gulf Coast, which hosts slightly over half of US refining capacity. It alone is equivalent in size to 85% of China's entire refining capacity—the country with the second largest refining system in the world.
- Refineries come in many types and sizes or what is known as "configurations". The configuration of a given refinery is a function of both the crude processed and the processing capability to convert this crude into usable end-user products, particularly light clean products (LCP).[34] The configuration of a refinery is integral to the quality of crude oil that can be processed efficiently and economically.
- Refineries are designed and most efficient for the particular quality of crude oil that matches the refinery's configuration. When a refinery processes crude oil that it was not designed to process, it will begin accumulating inefficiencies or processing penalties in the form of a lower yield of high-value transportation fuels, less than optimal utilization of equipment and eventually a reduction in processing capacity.
- Most of the refineries on the US Gulf Coast are designed to process a lower-quality crude oil than the LTO now being produced in abundance from US tight oil plays. To incentivize some of these Gulf Coast refineries to process LTO economically, the LTO price must be discounted well below its value on the international market. The discounting can range from $2-5 per barrel to more than $15 per barrel, depending on the marginal refining capacity needed.
- Currently, the price discount for LTO in the US Gulf Coast is in the $2-5 per barrel range, and the analysis in this section demonstrates that as LTO production continues to increase over the course of 2014-2015, this discount will become greater than $15 per barrel on a regular basis. This level of price discounting for US domestic crude oil will not have a proportional impact on lowering the price of US gasoline, which is freely traded and priced with international markets (as discussed in Section IV), but discounting will negatively impact investment in upstream production and thus reducing the contribution to the US economy.
- A policy change allowing the export of condensate only, as opposed to a broader crude oil export policy, could provide partial market relief. Some condensate is blended with crude oil for logistical and commercial reasons. The investment in new infrastructure to export unblended condensate faces the same challenge as refining investments for light crude—that dedicated pipeline investments from certain plays could be unnecessary with a further policy change.[35] Further, a policy that limits trade of one petroleum stream—no matter how defined—could create other unintended market distortions.

CRUDE OIL QUALITY AND GRADES

To this end, refineries are designed to process particular types of crude and efficiently produce them into finished products needed by consumers. Therefore, to understand the refining industry first requires an understanding of crude oil quality.

[34] A crude oil petroleum fraction is the volume percent in a barrel of crude oil that boils in a specified temperature range. Vacuum Gas Oil and Resid (or Residuum) are the two heaviest fractions of the barrel and those that require conversion to be consumed as LCP.

[35] Particularly from LTO plays located further inland.

What determines the price of crude oil? Factors such as global supply and demand, OPEC spare capacity, geopolitical tensions and supply disruptions influence the absolute price level of each of the global benchmark grades.[36] These factors tend to set absolute price levels, but there are important price differences among individual crude oils.

What determines the relative price of one type of crude oil against another? There are two main factors: quality and location. The physical properties or quality of a given type or grade of crude oil sets the value, or price, of that grade relative to other grades available in the same refining market. Quality differences, along with transportation costs, determine the price difference or spread between prices for two crude oils.

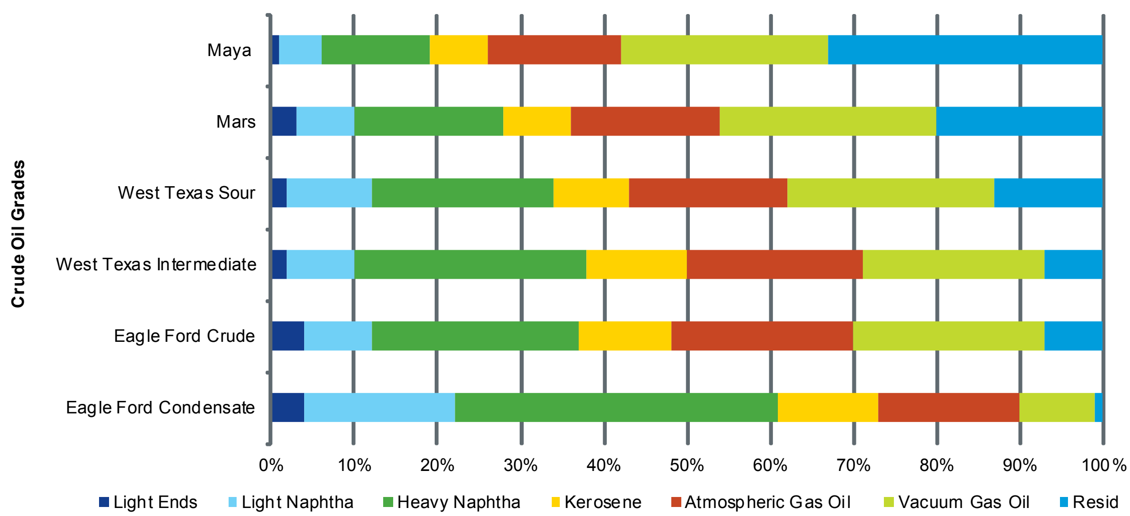
Many physical properties of crude oil can influence its quality and therefore its price. Two in particular have the largest effect on the price a refiner is willing to pay. One is density and the other is the level of impurities, such as sulfur. These two properties are important as show below:

- **Density:** This is measured in American Petroleum Institute (API) degrees, commonly referred to as API gravity. Counterintuitively, the API gravity scale is inverted. That is, the heavier crude oils have a lower API gravity. The importance of API gravity is that it gives a refiner an approximation of how much of the barrel has the right molecules in its natural state to be readily transformed into gasoline, jet and diesel fuels (collectively, LCPs) and how much of the barrel must go through more complex processing in order to be converted into those fuels. Light crude oils have a higher percentage of the barrel naturally in the desired range to be easily transformed into LCP, and therefore typically have a higher price than heavy crude. Heavy crude oils have a higher percentage of the barrel that must be converted into LCP, requiring higher capital investment and operating costs. This is the economic reason why heavy crude oils have a lower price relative to light crude oils. For purposes of this analysis, IHS uses the following crude oil grade definitions:
    - **Heavy:** Crude oils with an API gravity of less than 24. These grades include Western Canada Oil Sands, California Central Valley, Mexico Maya and Venezuelan Merey.
    - **Medium:** Crude oils with an API gravity greater than or equal to 24 and less than 32. These grades include Saudi Arabia Medium, Iraq Basrah and US Gulf of Mexico Mars and Poseidon.
    - **Light:** Crude oils with an API gravity greater than or equal to 32 and less than 42. These grades include North Sea Brent, Nigeria and Angola West African Baskets, Light Louisiana Sweet, West Texas Intermediate, Alaska North Slope, Saudi Arabia Arab Light and Russian Urals.
    - **Ultra Light:** Crude oils with an API gravity greater than or equal to 42 and less than 50. These grades have historically included Algerian Saharan Blend and Malaysian Tapis. However, ultra-light now also includes many of the LTOs being produced in the United States, such as the Bakken and Eagle Ford.
    - **Condensate:** Field condensate is generally produced from the condensation of liquids from gas wells. This liquid is typically comprised of very light oils with a high API gravity. Much of the condensate produced is not marketed separately but is blended into nearby crude oil streams, which both increases value and reduces infrastructure costs.

[36] Brent and West Texas Intermediate crude.

As shown in Figure 3.1 below, the natural yield of crude oil fractions—from light ends to resid—varies considerably between heavy and light crude oils:[37]

FIGURE 3.1
Crude Oil Petroleum Fraction Yield



Source: IHS Energy

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- **Impurities:** The concentration of impurities in crude oil, such as sulfur and nitrogen, must be removed prior to end-use (combustion). These impurities are typically measured in weight percent. A crude oil with a high concentration of sulfur (greater than 1 weight percent) is called sour; those with a low concentration (less than 1 weight percent) are called sweet. The impurity specifications for LCP are often dictated by country or regional environmental standards. For example, the finished product specification for gasoline in the United States is 30 parts per million by weight (wppm) and 15 wppm for diesel. A sour crude oil of 1 weight percent sulfur, or 10,000 wppm sulfur concentration, must have 99.7% of the sulfur removed in the refinery prior to distribution and sales. Crudes with a higher sulfur concentration are more expensive to process since the removal of sulfur is done using high temperatures (energy), catalysts (chemicals) and hydrogen (derived from natural gas).[38]

For the purposes of this study, the heavy sour and heavy sweet grades will be commonly referred to as *heavy*, the light and medium sour grades will be discussed as a combined crude grade referred to as *sour*. The light, ultra light and medium sweet crude grades are also referred to as *sweet*. The reasons for doing this are rooted in the reality that production volumes for heavy sweet and medium sweet crude oils are small and not major grades processed in the US refining system, nor are US refineries configured specifically for those grades of production

[37] A crude oil fraction is the volume percent in a barrel of crude oil that boils in a specified temperature range. Vacuum Gas Oil and Resid (or Residuum) are the two heaviest fractions of the barrel and those that require conversion to LCP.
[38] The majority of hydrogen used by refineries to remove impurities is produced from natural gas.

TYPICAL REFINERY CONFIGURATIONS

No two refineries are identical; some basic characteristics and configuration types are provided:

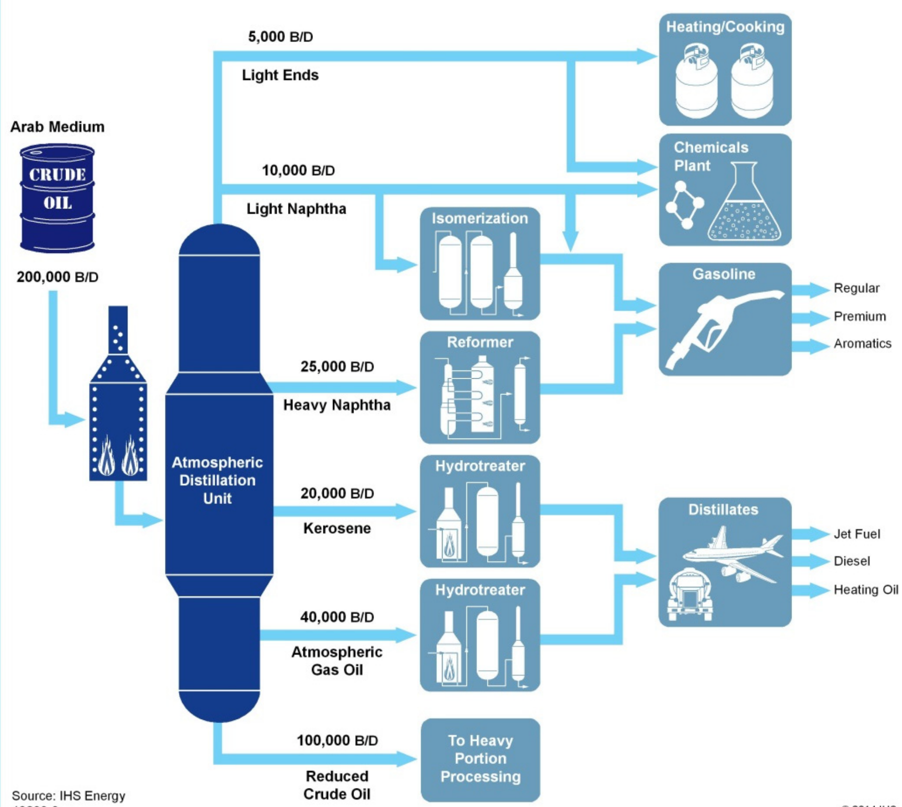
- **Size:** A refinery's capacity or throughput is the volume of crude oil and other feedstocks capable of being processed, normally expressed in barrels per day. Refineries range in size from 1,000 B/D to as much as 900,000 B/D.[39]
- **Ownership:** A refinery's ownership can be in the form of 1) an independent refinery, 2) a joint venture (JV), 3) an international oil company or 4) a national oil company. Independent refineries are commonly owned by public or private companies or financial institutions. The ownership interests of a refinery can have an influence on the operation and crude slate of a given refinery.[40] Several refineries in the United States operate as JVs with an international oil company providing refinery operational and fuels marketing expertise and a national oil company providing a steady supply of crude oil via a long term supply agreement.
- **Target Market:** The target market of the refinery's production can range from the transportation fuels market (most refineries) to a specialty market such as lubricating oils, refrigeration and transformer oils, asphalt or petrochemical feedstocks. Specialty refineries are much smaller in size, with typical capacities of roughly one-tenth that of fuels refineries, and are often tied to processing a few grades of crude oil with specific properties.
- **Configuration:** The configuration of a refinery can be defined as the fraction of the crude oil barrel a refinery is capable of processing into LCP. Each petroleum fraction has different processing or hardware requirements to transform that fraction into a finished product. Crude oil grades have a high degree of variability in the petroleum fractions they yield (Figure 3.1). Refiners configured for light crude oil have much more and larger hardware for the light fractions of the barrel, with the opposite being true for refiners configured for heavy crude oil. Figures 3.2 and 3.3 illustrate the typical fractions, and hardware and configuration for a full conversion coking refinery processing Arab Medium crude oil. Arab Medium was selected because this grade represents a balanced crude oil barrel; when fractionated, there is a 50/50 split between light and heavy portions. Graphically, the refinery is divided into two parts: Figure 3.2 showing the light processing portion of the barrel and Figure 3.3 showing the heavy processing portion of the barrel.

Refineries are typically grouped into one of four standard configurations based on processing hardware and the petroleum fractions they are capable of converting into LCP. The four standard configurations used in this report are the following:

- **Topping:** This type of refinery includes only primary distillation or fractionation equipment and no other downstream processing hardware. A topping refinery is the simplest refinery to construct and has the lowest capital investment threshold; however, it produces few, if any, finished products, and no gasoline.
- **Hydroskimming:** This refinery includes primary distillation equipment and downstream processing units for the natural light fractions of the barrel. This configuration is typically capable of producing gasoline, jet fuel and diesel, but only in proportion to the natural yield of the crude oil barrel. A hydroskimming refinery does not contain any conversion hardware for the two heavy fractions in the bottom portion of the crude oil barrel.[41] These heavy fractions are sold as a low-value product, such as residual fuel oil (RFO), generally priced at less than the crude purchased.

[39] The capacity of a refinery can be expressed in either stream day terms—the 100% full design capacity of the refinery—or in calendar days which recalibrates a refinery's capacity for maintenance and economic factors that can prevent full utilization.
[40] A crude slate is the mix of crude oils that a refinery processes.
[41] The bottom portion of the barrel is defined as the Vacuum Gas Oil (VGO) fraction plus the Resid fraction.

FIGURE 3.2
Typical Refinery Configuration for the Light Portion of the Barrel



Source: IHS Energy
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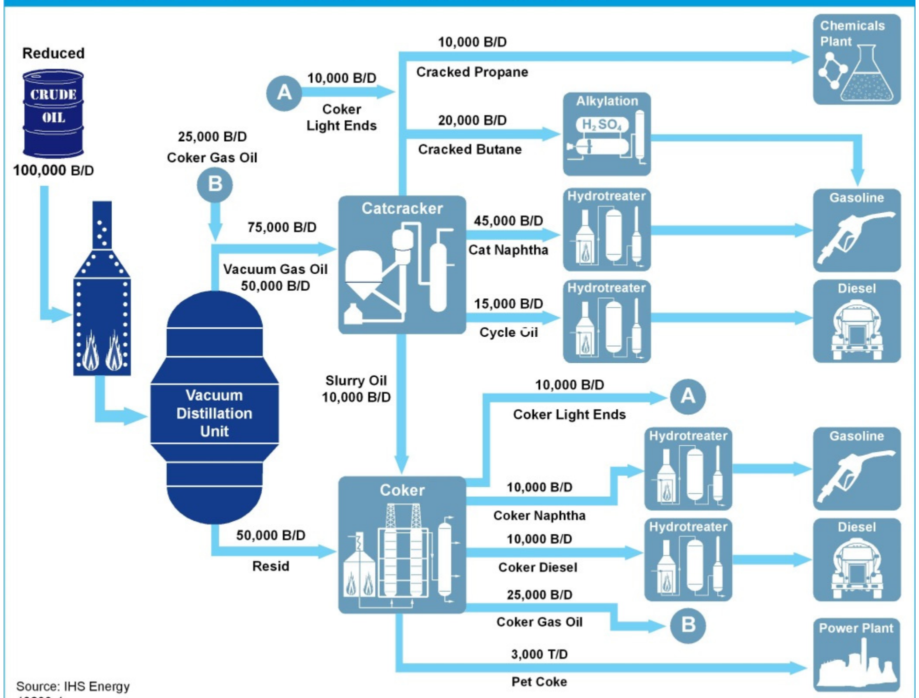
FIGURE 3.3
Typical Refinery Configuration for the Heavy Portion of the Barrel



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- **Cracking:** This refinery includes a hydroskimming refinery with added vacuum gas oil (one of the two heavy fractions of a crude oil barrel) conversion equipment in the form of a catcracker or hydrocracker. The transition from a hydroskimming to a cracking refinery represents a major increase in investment, but also a major increase in LCP output. The heaviest fraction of the crude oil barrel (known as resid) remains unconverted in this configuration and is sold as low value RFO. It is important to note that demand for RFO has been steadily falling since the 1970s, as it is no longer widely utilized as power plant fuel. As the global crude slate has, until recently, been getting progressively heavier, refiners have responded to declining RFO demand by investing in cracking and coking to convert low value RFO to LCP.
- **Coking:** This refinery includes a cracking refinery that has added resid (the heaviest fraction of a crude oil barrel) conversion equipment, usually in the form of a delayed coker. The next step in a coking configuration represents a large jump in investment but includes the benefit that the refinery is now able to convert the full barrel into LCP. One of the primary variables that differentiates a light crude oil from a heavy crude oil is the resid yield. While light crudes typically have a yield of less than 10%, heavy crude oils typically have a resid yield of greater than 30%. Most of the coking refineries, both in the United States and globally, have been configured to process heavy grades of crude oil that are lower in price, but that also have greater amounts of resid that need to be converted to LCP.

MATCHING CRUDE OIL QUALITY WITH REFINING CONFIGURATIONS

The two key parameters in the design of a refinery are the combination of 1) the expected grades of crude oil to be processed and 2) the degree of conversion to LCP necessary to meet expected LCP demand. Based on these input parameters, regions that produce heavy crude oils tend to build more coking refineries than regions that produce lighter crude oils. This is done because the vast majority of global refined product demand is for LCP, so properly matching a refinery configuration to the expected availability of crude oil grades is critical to being a viable business.

A refinery's objective is to produce high-value finished products (e.g., gasoline, diesel). This goal can be met when the crude quality and natural yield is matched with the refinery configuration.

However, if the crude quality is changed enough, the yields in the refinery no longer match the processing capacity, and not all products can be produced to a finished state for sale. At this point, the refinery is suboptimal and operating in an inefficient manner to process a crude oil quality for which it was not designed. One of the outcomes is that unfinished products are produced, which have a lower value, because they require further processing to be upgraded into an LCP. An unfinished product is a crude oil fraction that has been distilled, but has not gone through the necessary treating or conversion steps to be blended into a finished LCP. An example of this would be atmospheric gas oil with a sulfur concentration too high to be blended into diesel or home heating oil. To illustrate the matching of crude oil quality with configuration, Table 3.1, provides a matrix of crude oil quality along the top row, with refinery configurations down the left column. The typical ratios are shown for finished to unfinished refinery products produced across the grades of crude oil and configurations of refineries:

TABLE 3.1
Matching Crude Oil Grade to Refinery Configuration
(percent product yield)

	Condensate		Light Sweet		Light Sour		Medium Sour		Heavy Sour	
	Finished	Unfinished	Finished	Unfinished	Finished	Unfinished	Finished	Unfinished	Finished	Unfinished
Refinery Configuration										
Topping	-	100	-	100	-	100	-	100	-	100
Hydroskimming	92	8	70	30	62	38	54	46	42	58
Cracking	100	-	93	7	87	13	81	19	67	33
Coking	100	-	100	-	100	-	100	-	100	-

Source: IHS Energy

At the bookends, topping refineries produce all unfinished products, and coking refineries produce all finished products.[42] The middle three configurations are all sensitive to crude oil quality. When heavier crudes are processed in the hydroskimming or cracking refineries, more low value unfinished products are produced, as the simple refineries do not have the hardware to convert the bottom portion of the barrel into LCP.

A coking refinery that processes a heavy sour crude oil has the majority of its hardware designed to handle the bottom portion of the barrel but only minimal hardware for processing the light portion of the barrel.[43] When lighter crudes are processed in complex refineries, more low-value products are also produced. Only this time, these low-value products are unfinished light products, rather than heavy products like RFO. Although RFO is technically a finished product in that it has a developed end-use market, the price of RFO is low enough that it is valued the same as an unfinished product by most refineries.

Coking refineries that process medium and heavy sour crude grades typically are designed with less hardware to process the lower natural yields of naphtha, jet and diesel fuel produced from these heavy crude oils. Over-investment is not common given the high investment costs.

When market forces such as the oversupply of a given grade of crude oil emerge, it is possible that the medium and heavy sour, full conversion coking refineries have the proper crude oil pricing incentives to substitute their heavier, lower-quality crude oil for lighter, higher-quality crude oil. However, the challenge for the medium and heavy sour coking refineries is that they have too much processing capacity at the bottom of the barrel and not enough processing capacity at the top of the barrel. The processing of lighter, higher-quality crude oil will result in operational inefficiencies, higher costs and financial penalties. In order to incentivize a heavy crude refinery to process light crude, the pricing must be such that the reduction in crude costs offsets the penalties being incurred. The inefficiencies and penalties expected for medium and heavy crude refineries processing light crude oils are discussed later in this section, in Refining Crude Substitution.

NORTH AMERICAN REFINING SYSTEM

The United States contains the largest refining capacity of any country in the world, with 133 operating refineries with a combined crude oil distillation capacity of 17.9 million B/D.[44] When the United States' NAFTA partners—Mexico and Canada—are included, total refining capacity for North America increases to 21.8 million B/D. The US refining system is characterized not only by the number and size of refineries but also by a high number of world-class, high-complexity, full conversion refineries with a substantial degree of petrochemical and specialty products integration.

US demand for the heavy portion of the barrel is minimal. Current US demand for the heavy portion of the barrel directly usable as finished products—lubricating oils, waxes, asphalt, RFO and petroleum coke—is less than 5% of total US crude oil demand. The complexity and level of sophistication of the US refining system is driven by market forces that require conversion of anywhere from 30-60% of the crude oil barrel (the heavy portion) from products with almost no demand into high-demand, finished transportation fuels.

[42] Based on LCP production relative to fuel oil. In practice, coking refineries produce some low value products in petroleum coke and catcracker slurry oils, which are not shown to simplify the table.
[43] The light portion of the barrel is defined as the Light Naphtha fraction plus the Heavy Naphtha fraction, both of which are commonly further processed into gasoline.
[44] Stream Day Capacity or Maximum Capacity Averaged over 30 Days, Annual Average Capacity is typically about 95% of Stream Day Capacity.

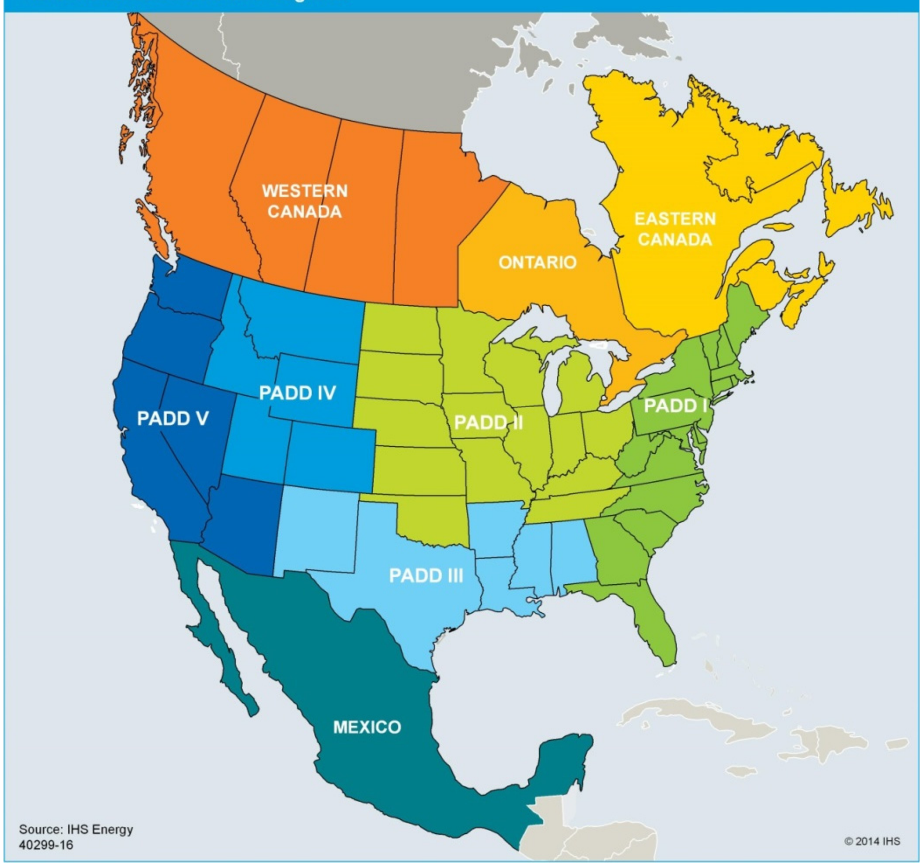
TABLE 3.2
Key Region Refining Configurations
(million barrels per day)

	Total Refinery Capacity	Cracking Configuration	Coking Configuration	% Cracking	% Coking
United States	17.9	4.6	12.5	26%	70%
Europe	15.7	11.0	2.9	70%	18%
China	11.0	2.1	8.5	19%	78%
India	4.4	1.7	2.7	37%	62%
Russia	6.0	2.5	1.7	42%	29%
North America (inc. Mexico)	17.9	4.6	12.5	26%	70%

Source: IHS Energy

A point of comparison in Table 3.2 above are the refining systems of Europe and the United States. Even though both markets have a high demand for LCP, the European refining system was largely designed around light sweet North Sea and North African crude oils. Due to this, Europe's refineries never made large-scale investments to upgrade their cracking refineries into coking refineries. The United States, by contrast, invested heavily in its refining system to process heavy Canadian, Mexican and Venezuelan crude oils and needs a much higher percentage of coking configuration refineries to produce the same LCP output. Another market factor over the past two decades was that RFO demand remained higher in Europe due to less RFO inter-fuel completion from low-cost natural gas and coal compared to the US market.

FIGURE 3.4
North America PADDs and Regions



For practical, logistical and interconnectivity purposes, US petroleum supply and distribution is subdivided into five Petroleum Administration Defense Districts (PADDs). Canada is subdivided into three additional refining regions, while Mexico consists of one large refining region. Mexico is more isolated than the United States and Canada, as Mexico contains no cross-border crude oil pipelines with the United States and only several small refined product interconnections. In contrast, the United States and Canada represent a truly integrated crude oil and refined product distribution system, with numerous cross-border pipelines connecting the two countries, as well as growing rail connections.

Due to a variety of factors such as refined product demand, local and regional availability of grades of crude oil, marine access and pipeline infrastructure, the refining system of each region has evolved differently and often contains markedly divergent footprints in terms of capacity, prevalent configuration type, and historic grade or crude slate. The following section of the report provides a brief overview of each North American refining region and how each region is expected to evolve with the growing overabundance of LTO.

Each region of the North American refining system plays a role in balancing the total inflows and outflows of crude oil into the US refining system. However, given the impending LTO oversupply, the importance of each refining region in North America is not proportional. PADD III—with just over half of total US refining capacity—is expected to take center stage in the coming years.

TABLE 3.3
North American Refining Configuration
(millions barrels per day)

Region	Number of Refineries	Total Distillation Capacity (DC)	Total DC @ 90%	Topping / HDS	LSW Cracking	LSR/MSR Cracking	LSW Coking	LSR/MSR Coking	HSR Coking
United States									
PADD I	9	1.3	1.1	0.1	0.8	0.1	-	0.3	-
PADD II	26	3.8	3.5	-	0.7	0.4	0.3	0.7	1.8
PADD III	52	9.2	8.2	0.3	1.1	0.7	0.6	3.8	2.7
PADD IV	16	0.6	0.6	-	0.2	0.1	-	-	0.3
PADD V	30	3.0	2.7	0.3	0.4	0.3	-	1.2	0.8
Total U.S.	133	17.9	16.1	0.8	3.1	1.5	0.9	6.1	5.6
Canada									
Eastern Canada	4	0.8	0.7	-	0.7	0.1	-	-	-
Ontario	5	0.5	0.4	0.1	0.1	0.2	-	-	0.1
Western Canada	8	0.7	0.6	-	0.3	-	-	-	0.3
Total Canada	17	1.9	1.7	0.1	1.1	0.3	-	-	0.4
Total North America	**150**	**19.8**	**17.8**	**0.9**	**4.1**	**1.8**	**0.9**	**6.1**	**5.9**

Source: IHS Energy

Particularly as it relates to the substituting of light domestically produced crude oil for heavier imports, the decisions made by Gulf Coast refiners and the balancing steps taken by 15-20 key refineries in the Gulf Coast region will drive the price signals and production impacts as the oversupply develops and persists. As such, the following section will primarily focus on PADD III. The diminished role of the US regions outside PADD III in affecting the North America crude oil balances and prices is described briefly below:[45]

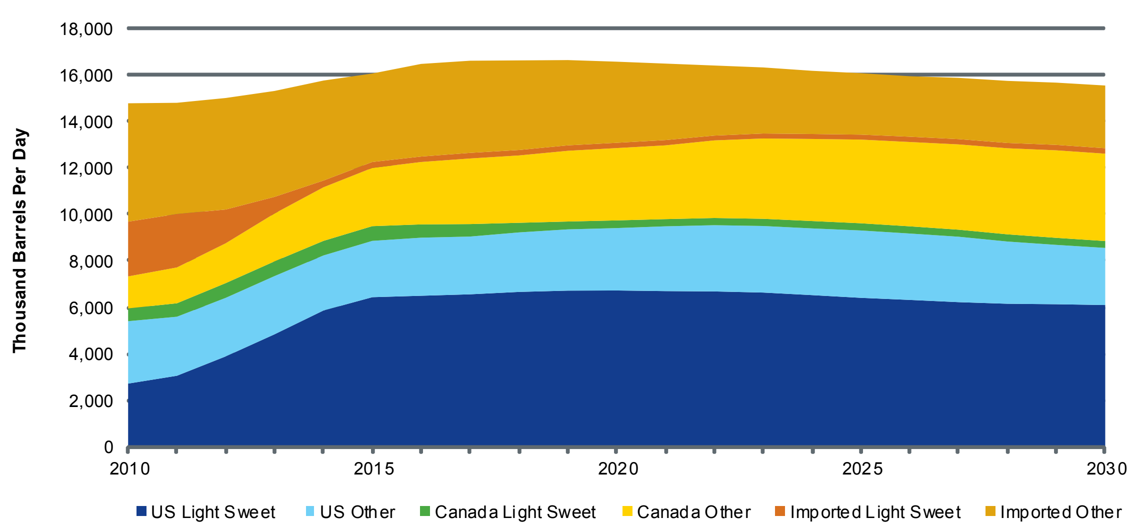
- **PADD I – Eastern United States and Eastern Canada:** The majority of refineries in these two regions have historically processed a crude slate of light sweet grades sourced from offshore Canada, the North Sea and, notably, West Africa. Due to these historic sources of crude supply, the majority of the region's refineries are already configured to process light sweet grades such as LTO. As rail infrastructure has been developed recently, the displacement of imports occurred rapidly. IHS forecasts that by the end of 2014, virtually all

[45] For a more detailed discussion on the mechanics of these other regions, see Appendix C.

light sweet and the majority of all imports will be displaced from these two regions. The impact is already clear in terms of imports of West African crude into PADD I. They have fallen 75%, from 524,000 B/D in January 2011 to 135,000 B/D in January 2014. Since most of the refineries in PADD I and Eastern Canada are configured for light sweet crude, the replacement of an import with domestic production represents a like-for-like substitution, and no major processing limitations are expected for this region. The reversal and completion of several pipeline projects on the Canadian side of the border will provide a broader mix of delivery options. These projects are expected to be in place between 2016 and 2018.

- **PADD II, PADD IV, Ontario and Western Canada – North American Midwest:** Historically, offshore imports have been an important piece of the crude supply landscape for this large region. However, the growth of production from US LTO and Western Canada oil sands has displaced virtually all imports from outside North America. When considering the United States and Canada as an integrated energy market largely due to their pipeline interconnectivity, there are no remaining imports to displace in this region. For the foreseeable future, IHS expects all of the region's refineries to be supplied with North American produced crude oil. As such, the North American Midwest refining region will not play a large role in influencing in the ability and cost of replacing light and medium sour imports with LTO.
- **PADD V – US West Coast:** The West Coast has historically been supplied with light sour Alaska North Slope and heavy sour crude oil from California's Central Valley. As a result, PADD V has historically not been a large importer and processor of light crude oils. IHS expects moderate volumes of LTO oil to be processed in PADD V, but it will be limited due to the configuration of the refineries in the region and a collection of California-specific regulations that make modifying refineries and adding infrastructure to deliver LTO by rail or marine more challenging than in other regions. These and several other regulatory measures will impede the large-scale processing of LTO in California and in the remainder of the West Coast.

FIGURE 3.5
Total US Refinery Crude Oil Runs by Grade and Source



Source: IHS Energy, EIA

- **PADD III – US Gulf Coast:** The Gulf Coast is the largest, most diverse and sophisticated refining region in North America and represents the premier refining hub in the world. The Gulf Coast stands out in terms of the number of refineries (52), total distillation capacity

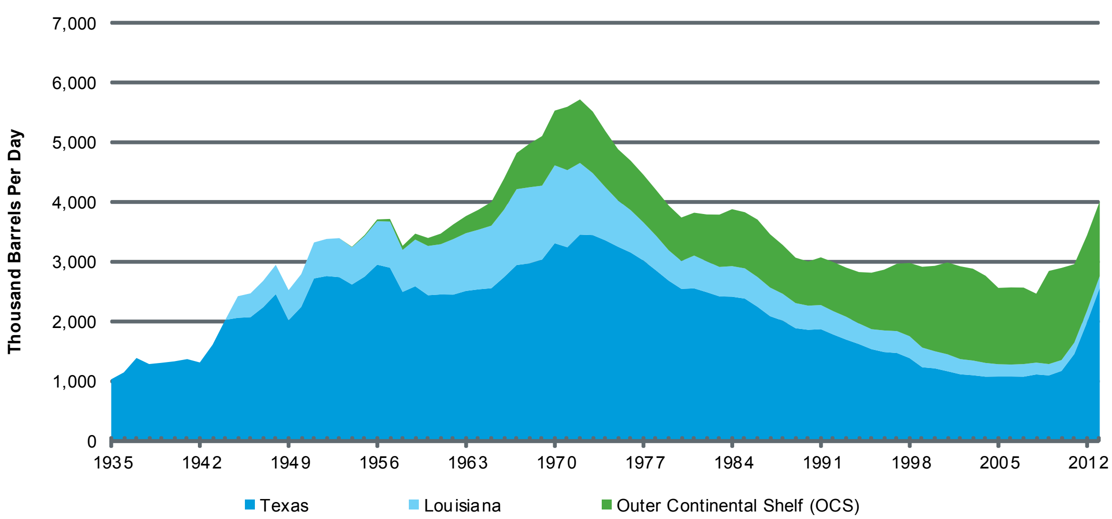
(9.2 million B/D), significant petrochemicals integration and the presence of several truly world class facilities. To put this in perspective, PADD III alone is equivalent to 85% of the refining capacity in of all of China—the country with the second largest refining system in the world. Both with and without revisions to US trade policies, PADD III is expected to become the epicenter of LTO crude substitution, replacing sour imports with LTO and driving the crude oil price signals that IHS anticipates will emerge over the next 12-24 months. Crude substitution is defined in greater detail and quantified later in this section.

PADD III refined product demand stands at 3.3 million B/D, equivalent to only about one-third of the region's refining capacity. This large difference between refining capacity and demand enables PADD III to 1) cover most refined product deficits for the remainder of the United States, and 2) serve as the largest exporter of refined products globally. Most of the major refined product systems that supply the Midwest and East Coast originate in PADD III, coming from Houston, Beaumont or Baton Rouge. As a standalone nation, PADD III would be number one in terms of refined product exports.

Given the extremely long and sustained history of both onshore and offshore production in the region, it is only natural that it developed a parallel, large-scale and sophisticated refining system. Moreover, PADD III had the advantage of a 50-year head start over much of the rest of the world. Originally built to process regional grades of oil, the region's refineries made investment over the years to reconfigure the refineries for the anticipated future availability of global production grades.

Texas production grew to an all-time high of 3.5 million B/D in 1972, before beginning a seemingly irreversible decline to 1.1 million B/D in 2007.[46] This decline, only partly offset by development of deepwater Gulf of Mexico supplies, forced refineries of the region to make additional heavy investments to retool their operations in order to remain viable. At the same time, US oil imports were rising. Reshaping of Gulf Coast refineries was centered initially on processing increasing volumes of light and medium sour Middle Eastern crude oils.

FIGURE 3.6
PADD III Gulf Coast Crude Oil Production



Source: IHS Energy, EIA, Texas Railroad Commission, Louisiana Department of Natural Resources

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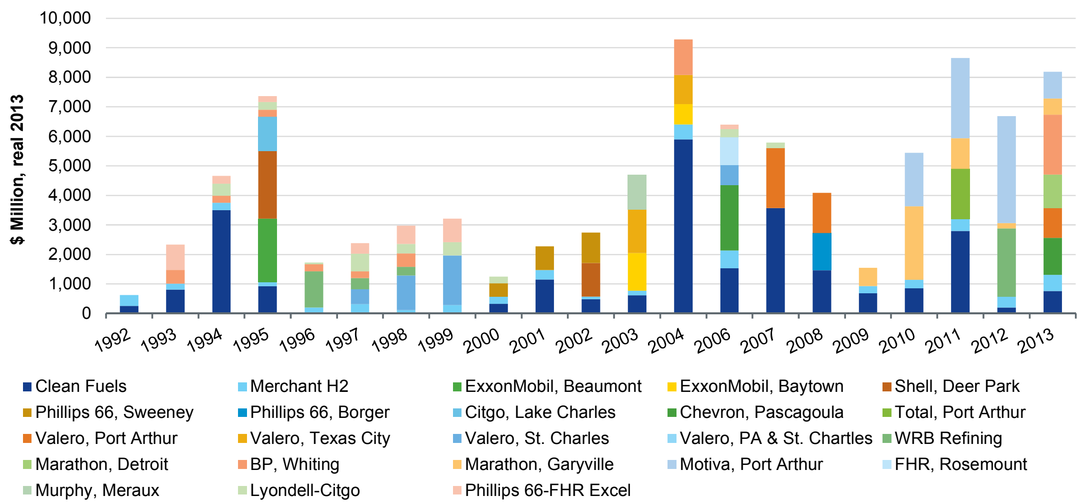
[46] Total Gulf Coast (Texas, Louisiana, Outer Continental Shelf) production peaked in the same year at 5.7 million B/D, the nadir was reached in 2008 with a regional production of 2.5 million B/D the lowest level since 1945.

BUILDING A WORLD CLASS REFINING SYSTEM

Since 1992, PADDs II and III (the Midwest, Midcontinent and Gulf Coast regions) have together invested over $100 billion to become the premier processing hub for low-quality crude oils ($85 billion in PADD III alone). This transformation occurred in response to the changing crude slates and in conjunction with three major clean fuels regulatory initiatives: low-sulfur diesel, Tier II gasoline and ultra-low sulfur diesel. IHS has evaluated the specific projects that occurred over this period and utilized a proprietary replacement cost model to calculate the direct capital investment made since 1992, shown below:

FIGURE 3.7
Major Heavy-Up Projects & Clean Fuels Related Investments



Source: IHS Energy FHR = Flint Hills Resources, PA = Port Arthur

One example that is illustrative of the broader regional trend is Valero Saint Charles, formerly the Orion Refining Corporation and Good Hope Refining Company. Originally constructed as a 10,000 B/D simple topping refinery in 1969, the refinery received a major upgrade in the late 1970s when it was converted into a 200,000 B/D light sweet cracking (moderate complexity) refinery, tailored for a crude slate of shallow water Gulf of Mexico and other light crude oils. The investments in the late 1970s included the addition of capacity in atmospheric and vacuum distillation, visbreaker, catalytic cracking, sulfur plant and alkylation. After the refinery became financially insolvent in 1983, it was shuttered until 1994 when new ownership recommissioned the refinery behind a second major wave of investment. New investments in the refinery reconfigured the facility into a heavy sour coking facility, complete with revamped distillation units, a new catalytic cracker, a new large delayed coker and other treating and sulfur removal capacity. In 2003, the reconfigured refinery was purchased by Valero, which proceeded to invest an additional $4 billion into the facility, adding two hydrocrackers, additional hydrotreating capacity and a major redesign of the fluid catalytic cracker.

Today, the refinery is regarded as one of several premier heavy oil processing facilities on the Gulf Coast, running a mix of Latin American, Middle Eastern and Canadian heavy sour crude oils, as well as reduced crude oil (a crude-derived feedstock containing only the heavy portion of the barrel) from Russia and other countries.

What stands out for refineries such as Valero Saint Charles is the disparity between its ability to process both the light and heavy portions of the crude oil barrel. Today, the refinery has a crude throughput capacity of 190,000 B/D, but throughput is closer to 270,000 B/D when including reduced crude and other feedstocks. However, the refinery's naphtha processing capability is only 36,000 B/D, or 13% of feedstock capacity, while heavy oil (vacuum gas oil and resid) processing capacity is 85% of total feedstock throughput capacity. LTO, by contrast, yields 30-40% or more naphtha and only about 25-30% heavy oil. On paper, if Valero Saint Charles were to process a crude slate comprised of LTO, it would have a third of the capacity required for the light portion of the barrel and three times too much capacity for the heavy portion of the barrel.

Increasing production during the 1980s in Mexico and Venezuela provided Gulf Coast refineries with growing amounts of stable crude oil supply from a much closer proximity than the long distance supply chain from the Middle East. Starting in the late 1980s / early 1990s, a 25-year wave of investment occurred as the Gulf Coast system reconfigured to run the increasing volumes of Mexican and Venezuelan resources, which happened to be of the heavy sour type. At the same time, large capital projects were instituted to meet tighter environmental regulations. Altogether, this constituted a huge investment—more than $85 billion over less than a quarter of a century.[47]

In sum, two historic trends drove the huge investment in reconfiguring Gulf Coast refineries. One was what seemed to be the unstoppable decline in US production and the continuing increase in imports of lower-quality heavy oils that required much more processing. The other was a wave of increasingly tight environmental regulations that compounded processing costs, especially given the lower quality of the growing volumes of crude oil.

Although the Gulf Coast can be seen as one large refining complex, it breaks down into multiple refining hubs geographically distributed across the region. These clusters within the overall complex are typically connected by common crude and refined product infrastructure and are organized into the following:

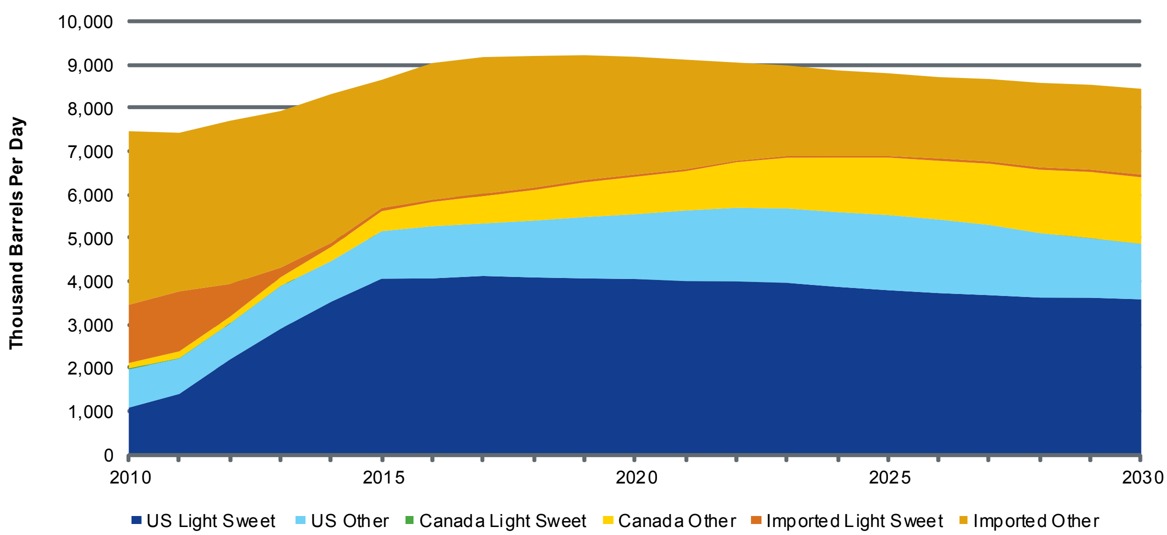
- **West Texas:** This region contains eight refineries with a total distillation capacity of 660,000 B/D that are geographically dispersed across New Mexico, West Texas and the Texas Panhandle down to the Eagle Ford region of Texas. These refineries are an equal mix of coking and cracking refineries whose crude slate is comprised of West Texas Intermediate, West Texas Sour and a moderate amount of Western Canada heavy sour.
- **PADD III Inland:** The Gulf Coast regions of East Texas, Arkansas, Northern Louisiana and inland Alabama and Mississippi contain 10 refineries with a total distillation capacity of 310,000 B/D. These facilities are much smaller than their Gulf Coast counterparts and are predominantly specialty lubricating oil and asphalt refineries running predominately domestic crude grades.
- **Corpus Christi:** Located at the far western and southern edge of the Gulf of Mexico, this interregional cluster contains five refineries with a total distillation capacity of 770,000 B/D. These refineries are full conversion coking and cracking refineries that have historically processed a diverse slate of domestic and imported barrels of all grades. The proximity of the cluster to the rapidly growing Eagle Ford formation has resulted in several of the refineries here switching to an Eagle Ford centric crude slate. Two refineries in the region are making investments to process increasing volumes of Eagle Ford crude oil.
- **Texas Gulf Coast (TXGC):** This hub has 13 refineries located in Sweeny, Texas City, the Houston Ship Channel, Beaumont and Port Arthur, with a total crude distillation capacity of 3.9 million B/D, including the two largest US refineries. These are all full conversion refineries with cracking and coking configurations and have a high degree of petrochemical interconnectivity. They process a crude slate comprised of all grades of domestic, Canadian and offshore imported crude oils.
- **Louisiana Gulf Coast:** Similar to TXGC, the Louisiana Gulf Coast hub crosses multiple regions including Lake Charles, Baton Rouge, Lower Mississippi River / New Orleans and the coastal regions of Mississippi and Alabama. The hub contains 14 refineries with a total distillation capacity of 3.5 million B/D and includes the third and fourth largest refineries in the United States. These refineries share many similarities with the TXGC refineries but tend to

[47] The investment in heavy crude processing and clean fuels increases to over $100 billion when including concurrent investment made in the US Midwest.

have a slightly better natural configuration for LTO due to the clusters' long history of processing light sweet crude oils produced from shallow water Gulf of Mexico.

The key point is that market and pricing dynamics are largely a function of crude slate and of the decisions made by refineries to balance the availability of crude oils, versus the ability of the refining system to efficiently process those available crude oils. The 32 refineries located in Corpus Christi and the Texas and Louisiana Gulf Coasts will be the main drivers of this dynamic. The market and pricing dynamics are complex, as all grades—domestic and imported—are in play. IHS expects these decisions to be driven by the economics of substituting one crude for another and by the size of the processing penalties incurred, as increasing volumes of lighter oil are processed in refineries that have been reconfigured for heavier and more sour grades of crude oil.

FIGURE 3.8
PADD III Refinery Crude Oil Runs by Grade and Source



Source: IHS Energy, EIA

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IMPORTANCE OF US GULF COAST REFINING SYSTEM

As discussed, the US refining system is large and dispersed. However, the US Gulf Coast (USGC) refiners are expected to be most important in terms of the pricing for crude oils and products for the following reasons:

- The USGC accounts for slightly over half of total US capacity.
- The USGC is an important product supplier to other major US demand centers, including the East Coast and Midwest, where demand exceeds refining capacity. It also has influence, though less direct interaction with, the Rocky Mountains and West Coast.
- The vast majority of US product exports originate from USGC refiners.
- Perhaps most important for this analysis, the USGC is a hub for key domestic and international crude oil grades including WTI, Eagle Ford, Bakken, Canadian oils sands and offshore medium and heavy sours grades.

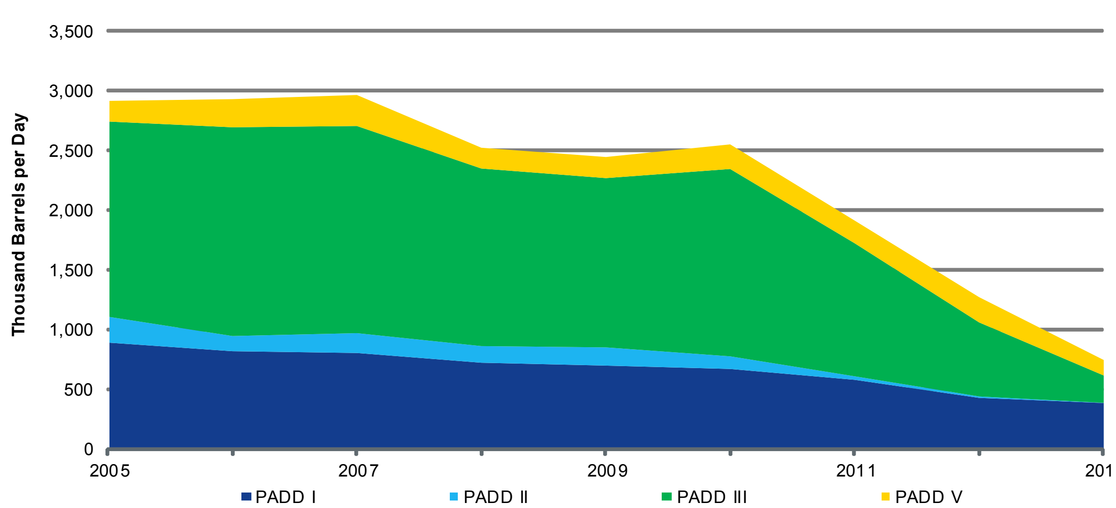
Refining Crude Substitution – The Four Tiers

As LTO volumes have increased, the downstream industry has shifted quickly to optimize its refineries to capture the available margin from crude oil grades that are in oversupply or logistically disadvantaged and depressed in price. The increasing consumption of domestic LTO in the refining system is referred to as a crude substitution in which LTO replaces traditional crude oils. Crude substitution refers to the simple replacement of one crude grade with another.[48] The quality difference between the two crude oil grades, in conjunction with the refinery internal capacities and constraints, dictates the products that can be produced. Based on the product price and the crude price, the profit from each crude oil can be estimated. A refinery will make a crude substitution only if the profit improvement warrants it.

The increasing substitution of LTO is swiftly moving through a series of tiers, with each tier imparting a potentially more significant economic loss for the refiner. To overcome the loss and incentivize processing requires a more significant LTO price discount. While the actual crude substitution varies by refinery, depending on configuration, scale, location and other factors, a generalization is useful in considering the overall refining system but particularly the PADD III supply and demand balance and pricing response. The LTO substitution tiers (or ways to process more LTO) include:

- **Tier 1 – Displacement of Light Crude Imports:** As production has increased in Canada and PADD II, light sweet crude overseas oil imports into PADD II Midwest and Midcontinent refiners have essentially ceased. US LTO production has rapidly reduced imports of these crude grades into the PADD III / US Gulf Coast region as well. Finally, observed reductions in the PADD I / East Coast region is currently underway as rail and tanker/barge movements of LTO have begun (Figure 3.9) in substantial volumes.

FIGURE 3.9
Non-Canadian Light Sweet Crude Oil Imports



Source: IHS Energy, EIA
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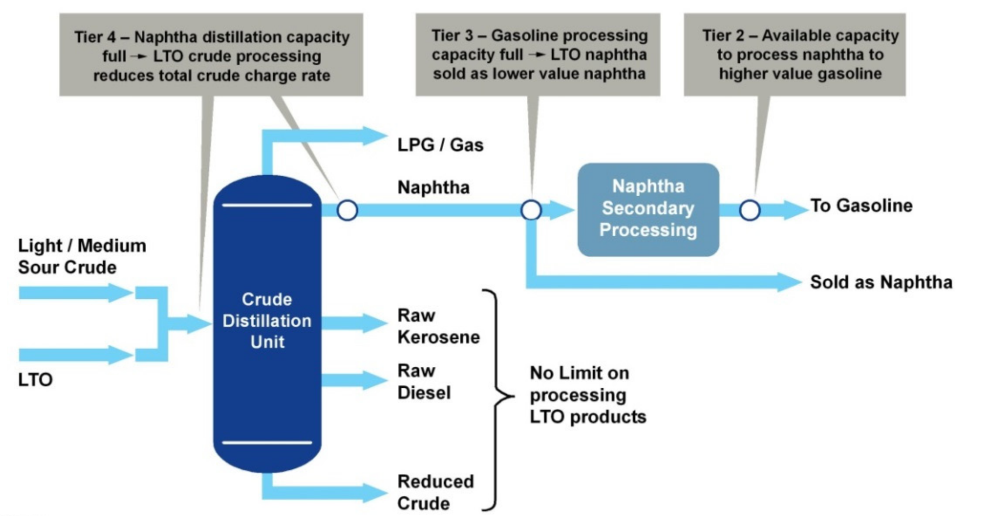
[48] Refineries use sophisticated models to simultaneous optimize multiple crude purchase, product production and refinery operations to maximize profits.

- **Tier 2 – Optimum Processing in Light / Medium Sour Capacity:** While the crude yields of LTO are notably different than light sour and medium sour crude yields (see Figure 3.10 below), there is some capacity in certain refineries to substitute LTO for sour crudes, particularly for imported light sour grades such as Arabian Light. This second tier of substitution is limited by the ability of these refineries to fully process all of the lighter distillation streams, such as naphtha and liquefied petroleum gas, into finished products at full crude charge rates (utilization). Most of the imported crude in this category consists of medium sour crude grades, which include Arabian Medium, Kuwait, Basrah and several grades from of Venezuela.
- **Tier 3 – Suboptimum Yield in Medium Sour Capacity:** As a refinery designed to process medium sour crude oil increases the amount of LTO substituted, it can reach limits in secondary processing and gasoline blending that result in a change in product output, known as Tier 3 substituting. The production and blending of gasoline requires significant secondary processing to remove contaminants, such as sulfur, and to rearrange molecules to improve quality, such as refining octane. As the amount of LTO processed increases, the available processing designed for medium sour crude limits the ability to process all the naphtha into finished gasoline. At this point, the refinery becomes suboptimal and begins producing unfinished products, which have a lower value. The refinery will still choose to take the suboptimal step if the LTO price carries a large enough discount. Tier 2 through Tier 4 are depicted in Figure 3.10 below.

FIGURE 3.10
Restricted Trade Impact on US Crude and Gasoline



Source: IHS Energy
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- **Tier 4 – Suboptimum Capacity Reduction in Medium Sour Capacity:** As a final step, refiners have the option of processing additional LTO to the point that the higher naphtha distillation yield results in a lower utilization (known as a reduced crude charge rate). At this point, the refinery incurs the lost opportunity cost of forgoing the medium sour crude margin, as the total crude rate is reduced. An example of this is provided in the Table 3.4, which shows that adding 25% LTO to the refinery crude charge results in a total crude charge reduction of 15%. The lost margin associated with the lower utilization must be recovered by lower LTO pricing.

The level of the LTO price discount needed to incentivize an individual refinery (or refinery system) to move from Tier 1 through Tier 4 increases.

TABLE 3.4 Suboptimum Capacity Reduction in Medium Sour Capacity (Tier 4)			
	Crude Charge (barrels per day)	Naphtha Yield (percent)	Naphtha Yield (barrels per day)
Full Medium Sour Processing			
Medium Sour Crude	200,000	25%	50,000
Light Tight Oil	0		
Total	**200,000**		**50,000**
			(Limiting Capacity)
Light Tight Oil Substitution for Medium Sour			
Medium Sour Crude	120,000	25%	30,000
Light Tight Oil	50,000	40%	20,000
Total	**170,000**		**50,000**
			(Limiting Capacity)
Light Tight Oil Percent of Capacity	**25%**		
Crude Charge Reduction	**15%**		

Notes: Illustrative only; values rounded for presentation.
Source: IHS Energy

Price Volatility and Seasonal Effects

In addition to the refining value discounts discussed, there will be periods when the supply of LTO does not match the demand for such grades of crude, even with available substitution. The most likely periods for these discounts are during the two primary maintenance seasons (fall and winter), when a notable amount of refining capacity is offline. Refineries at regular intervals clean, repair equipment and replace catalysts.[49] The normal planned maintenance interval for a refinery is every 4-5 years, and the maintenance work typically takes 6-8 weeks to perform. A reasonable expectation is that 20% of US refining capacity will be offline each year for two months. During this time, discounts can be particularly acute if a large amount of light crude refining capacity is undergoing maintenance at the same time.

As US LTO production increases, IHS expects the domestic crude discount to increase if US refiners do not have access to offshore export markets. Based on the rather large discounts observed in the Midcontinent in 2011-2012 ($25+ per barrel) and in the US Gulf Coast in 2013 ($15 per barrel), and considering that production growth is likely to exceed LTO refining capacity growth for at least the next 2-3 years, a volatility discount of about $10 per barrel is expected by 2016 without an export policy change.

US REFINING RESPONSE

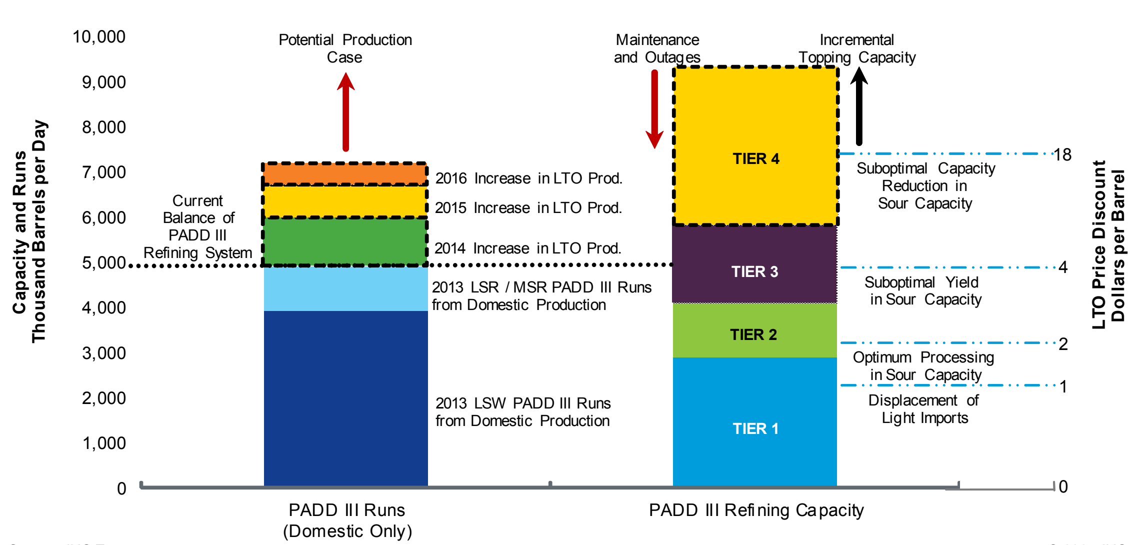
THE IMPACT OF INCREASED LIGHT TIGHT OIL—DISPLACEMENT ECONOMICS—IN TIER 3 MOVING TOWARD TIER 4

Figure 3.11 shows the US Gulf Coast processing tiers on the right side, with an estimated capacity to process LTO for each tier on the left side. The approximate LTO price discount associated with each tier is provided on the right axis. The price discount for Tier 1 through Tier 3 are modest, rising from $1-4 per barrel, but increase sharply for Tier 4, to $10-25 per barrel. Current domestic crude runs for these refineries and the expected total LTO growth over the next few years are depicted on the left side of the figure. The remaining area—the arrow on top of the PADD III Runs column—includes imported crude oils (not shown). This figure supports IHS' conclusion that the Gulf Coast refining system is already operating in Tier 3, which is consistent with the level of LTO price discount observed in the market (maintenance periods aside) today.

[49] Regular planned refinery maintenance periods are referred to as turnarounds.

It is important to note the increases in LTO runs over the coming years. A portion of this additional LTO will be processed in new topping capacity, but our analysis indicates that supply will outpace demand for the next several years, moving the Gulf Coast and the entire North American refining system into a structural Tier 4 operating mode.

FIGURE 3.11
US Gulf Coast Refinery Processing Tiers and Corresponding LTO Discount



Source: IHS Energy

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CONDENSATE AND PROCESSING

A prominent feature of the Great Revival of US crude production is the high percentage of ultra-light crude oil and condensate production. One of the more challenging issues in discussing condensate is definitional in nature. The traditional definition of condensate is the hydrocarbon liquid produced from the gas phase of a well that is heavier than liquefied petroleum gases, but lighter than raw crude oil or, alternately, the liquids from gas processing that remain a liquid at ambient conditions.[50]

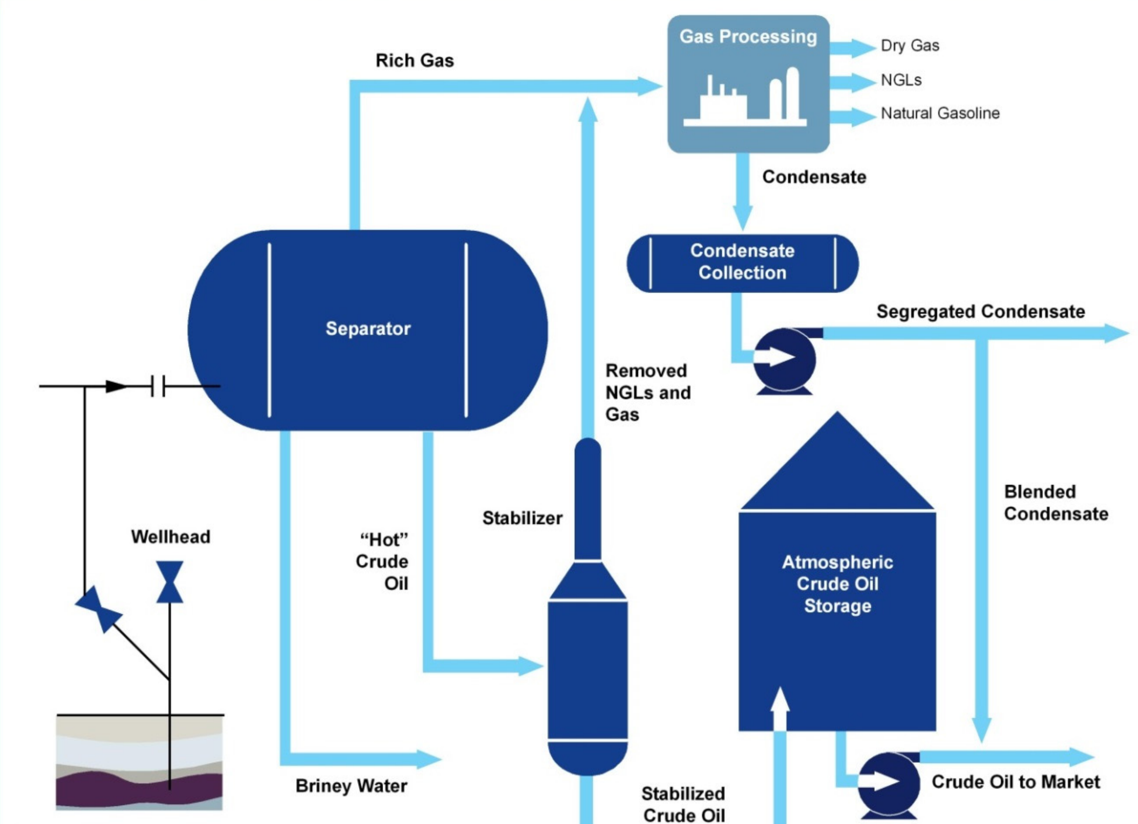
WHAT IS CONDENSATE?

When oil or gas wells are drilled, the hydrocarbons produced are a mixture of molecules from natural gas (methane) and heavier hydrocarbons defined as raw crude oil. Wells that are more gas-oriented are classified as gas wells; wells that are more liquids-oriented are classified as oil wells.

But where does the dividing line fall between an “oily gas” well and a “gassy oil” well? The next heaviest group of hydrocarbons after methane or dry natural gas are the liquefied petroleum gases, defined as the ethane, propane and butane molecular families.[51] Some gas processing arrangements produce heavier NGL streams, composed of a mixture of pentane and hexane molecules commonly referred to as natural gasoline or pentanes plus. The definitional gray area comes with this collection of hydrocarbons that generally boil in the range of gasoline and can be defined as either condensate or crude oil, depending on where the liquids stream is removed from oil and gas separation facilities, even though the two streams might be chemically similar or identical.

[50] Liquefied petroleum gasses (LPGs) will vaporize unless stored or transported under pressure.
[51] The NGLs have the following API gravities; Ethane – 266, Propane – 148, Butane – 111, Pentane 93, Hexane 82, Cyclohexane 49, and Benzene with an API of 29 the same as medium crude oil.

FIGURE 3.12
Oil and Gas Field Separation Diagram



Source: IHS Energy
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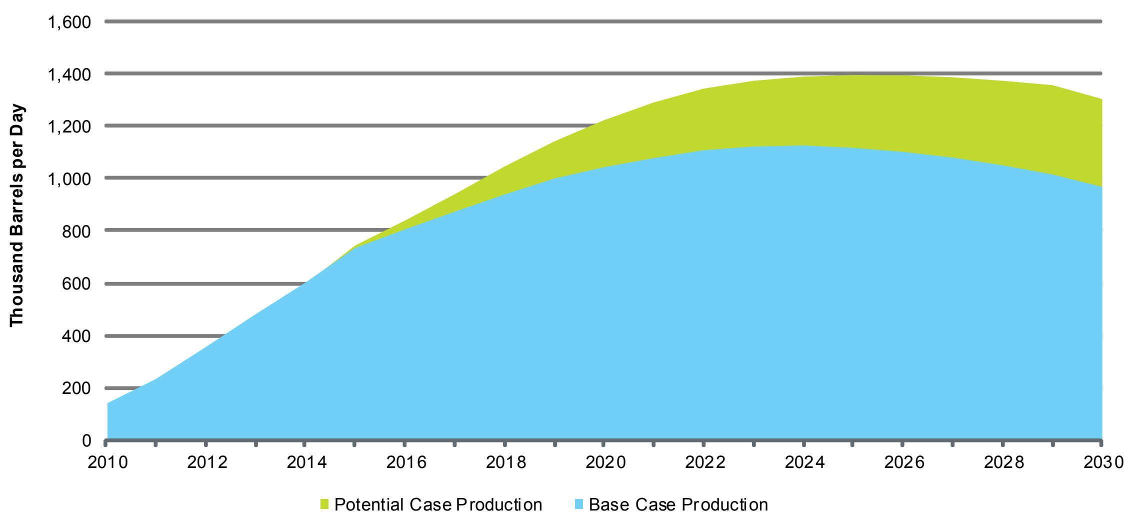
Historically, producers have re-blended condensate with crude oil during production, which has the effect of lightening or spiking the crude oil with a slightly lighter material. Producers do this for two reasons:

- Condensate is easier to handle if blended with oil. Condensate is more volatile than crude oil, holding properties of both NGLs and crude oil that would require a separate infrastructure to handle and transport if kept segregated (unblended with crude oil).
- Condensate is relatively deficient of diesel and heavier molecules valued by refiners and is typically priced at a discount to light crude oil. The blending of condensate into crude oil has the dual benefit, when done at appropriate levels, of increasing the value of both the crude oil and the condensate.

The production from US tight oil formations to date has included substantially higher production of condensate than from most conventional plays and wells. In plays such as the Bakken, the condensate production is small enough to be managed via traditional crude blending. However, in plays like the Eagle Ford, the production of segregated condensate is significant enough that it cannot all be disposed of via crude oil blending and is marketed as a product separate from crude oil.

Due to the definitional issues and the typical practice of blending condensate into crude oil, it is difficult to assess the true production levels of condensate (field production before blending) with no official standard or recognized source of condensate production information. IHS has used the fundamental play-level analysis performed for this study to provide production estimates and forecasts for condensate in both the Base and Potential Production Cases, shown below:

FIGURE 3.13
US Shale Gas and Tight Oil Condensate Production



Source: IHS Energy

REFINING CONDENSATE

As with LTO, the same questions exist with condensate: Can the US refining system efficiently process segregated condensate? And what constraints exist to absorb the full volume of produced condensate? The processing of condensate magnifies the challenges associated with processing surplus LTO, and even refineries configured for light crude oil will struggle to process additional volumes of condensate.

TABLE 3.5
Suboptimum Capacity Reduction in Light Sweet Tier when Substituting Condensate

	Crude Charge (barrels per day)	Naphtha Yield (percent)	Naphtha Yield (barrels per day)
Full Light Sweet Processing			
Light Tight Oil	200,000	40%	80,000
Condensate	0		
Total	**200,000**		**80,000**
			(Limiting Capacity)
Condensate Substitution for Light Tight Oil			
Light Tight Oil	125,000	40%	50,000
Condensate	50,000	60%	30,000
Total	**175,000**		**80,000**
			(Limiting Capacity)
Condensate Percent of Capacity	**25%**		
Crude Charge Reduction	**13%**		

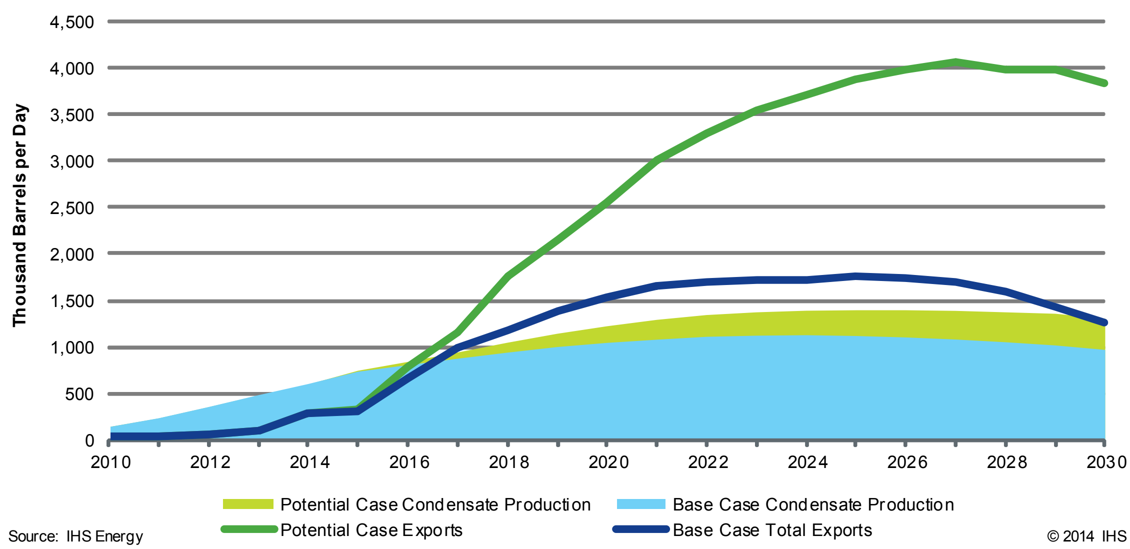
Notes: Illustrative only; values rounded for presentation.
Source: IHS Energy

The impact of substituting condensate into an LTO configured refinery is similar to the impact of substituting LTO into a medium sour configured refinery: a 15% reduction in the refinery's throughput capacity. The impact of forcing condensate into a medium sour refinery would have twice the operational and crude throughput reduction impact as that of substituting LTO into the same refinery.

EXPORTS OF CONDENSATE ONLY

As the policy discussion concerning crude oil exports has developed, one option is, at least initially, to permit the export of condensate only, and not crude oil. Using the crude oil production and refining balances prepared, Figure 3.14 compares crude oil exports (including exports to Canada) projected in the Free Trade Cases to the production of condensate from LTO developments. There are two important observations: 1) the crude oil exports modeled in both of the Free Trade Cases includes condensate and 2) the export of all of the field condensate produced requires new infrastructure.

FIGURE 3.14
US Tight Oil Plays Segregated Condensate Production and Total Forecasted Exports with Free Trade



Source: IHS Energy

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Figure 3.14, shown above, illustrates how the liberalized export of only condensate could provide an interim step in market relief. The area chart (light blue and green) in the background shows IHS' forecast for segregated condensate production from LTO plays in the Base and Potential Production Cases. The lines overlaid (dark blue and crude) in the foreground provides IHS' forecast for the level of non-Canadian exports projected in the Base and Potential Production Cases with free trade of all crude oil grades. If future condensate production is near the Base Production Case forecast, condensate exports could enable the US refining system to better balance its configuration with respect to the quality of domestic crude production, particularly between 2016 and 2020. In the Base Production Case, the difference between the expected LTO exports and condensate production is relatively small, at approximately 500,000 B/D, and could be absorbed into the existing refining system with moderate levels of crude substitution and investment in simple topping capacity additions. In the Potential Production Case, the free trade of condensate would delay, by 18-24 months, when the US refining system reaches the point of export Gridlock.

ISSUES AND CONSIDERATIONS

Even though exporting segregated condensate would help to alleviate congestion resulting from an overabundance of US production, important questions and concerns remain regarding this option. IHS has identified the following issues and considerations associated with a condensate-only free trade alternative:

In certain plays, such as Eagle Ford, condensate could be exported today, but in several of the other major plays, a separate infrastructure for handling segregated condensate does not exist. In these locations, the construction of a fourth oil and gas infrastructure system would be needed to parallel those that already exist for crude oil, NGLs and natural gas.[52] This would take time, a large capital investment and regulatory certainty to create. The coming export Gridlock will be reached well before this infrastructure could be in place. In contrast, the full free trade of crude oil already has the infrastructure in place and under development to quickly alleviate system congestion, providing a more ready and efficient solution.

Definitional inconsistency around what constitutes condensate would lead to confusion and the need for more complex definitions and more regulations and regulatory guidance. The following definitions could be adopted, though each poses its own challenges:

- **API Gravity Definition:** Set a threshold for when crude oil becomes condensate, for example an API gravity of 50. A bright line provided by a fixed API level would create incentives to "lighten" crude to just slightly above the API definition of condensate, via NGL and natural gasoline blending, in order to qualify for an export license.
- **Well Type Definition:** Use the historic definition of condensate as the ambient condition liquids produced from a gas well or a liquids-rich gas well. However, since there is no set definition of what constitutes an oil versus a gas well—there is actually a continuum—this type of definitional solution would be potentially difficult to implement. Additionally, if a policy is adopted that allows atmospheric liquids from a gas well to be classified and exported as condensate, design solutions would in some cases be implemented to shift wells into the gas column and to favor condensate production over crude oil production.

The selective application of free trade policies to condensate, but not crude oil, would advantage certain plays and producers over others. Producers with a large footprint in rich gas and condensate-rich plays such as the Eagle Ford would receive larger benefits than producers with a large footprint in LTO-rich plays such as the Bakken.

A long term policy of condensate only exports could create distortions of its own. As previously enumerated, there are large and widespread benefits of allowing the free trade of crude oil. While a condensates only policy would be an improvement on the current ban, it would not maximize the full benefits of free trade.

The above issues will need to be considered against the advantages of enabling free trade of condensates as an interim step in relieving the market Gridlock and moving ahead on the free trade of crude oil exports overall.

In summary, the surge in domestic oil production has dramatically changed the US oil landscape. But the US refining system, particularly the huge Gulf Coast complex, is significantly geared to processing heavy oil and is limited in its ability to handle the light crude. This has created the Gridlock in the US domestic oil industry between upstream and downstream. To try to force more into the refining system will require steeper discounts, which will negatively affect investment, production, and employment. Allowing exports of excess LTO will relieve this Gridlock.

But what will be the impact on crude oil and gasoline prices? This is the topic we take up in the next section.

[52] Namely the Bakken and other Midcontinent tight oil plays.

IV. US PRICE RESPONSE

KEY INSIGHTS

- The global market price of crude oil is the single most important factor determining US gasoline prices. Lower international crude oil prices in general lead to lower gasoline prices in the United States. The opposite is also true.
- Existing export restrictions negatively impact US consumers. The benefit to consumers of a crude oil free trade policy is an estimated at 8 cents per gallon (Base Production) and 12 cents per gallon (Potential Production) reduction in the price of gasoline and transportation fuels.[53] This would result in $265 billion (Base Production) and $418 billion (Potential Production) in savings to American consumers over the 15-year period modeled in this report.
- The Great Revival in US crude production is lowering world oil prices from what they would otherwise be as US crude oil imports are diverted to non-US markets. Free trade can further lower prices by adding greater supply to global markets. As US crude production grows under a free trade policy change, international crude prices are estimated to decline by $3-$5 per barrel over the 15-year period modeled, depending on the US production increase, which is forecasted to add 1-2 million to global supply.[54]
- The price of US gasoline is linked to global gasoline and crude oil markets—not to the price of US crude oil. This means lower prices for US crude oil—with the current restricted trade policy—do not translate into lower prices for US gasoline. US gasoline prices are and will continue to be priced relative to international crude oil and gasoline prices. Therefore, removing the current price distortion on domestic crude through free trade should not increase US gasoline prices, as some might otherwise have expected.
- The crude export ban is distorting the price of US crude oils. With an inability to export, US prices are being discounted relative to international crude oils, and this discount will continue until an export policy change is made. As crude production increases, the current policy will increase the price distortion to a level of $15-25 per barrel in 2016 and 2017 and more than $8 per barrel on average for the 2016-2030 period analyzed. This level of crude price discount was observed in 2011-2012 in Cushing, Oklahoma, due to logistics bottlenecks and again in the US Gulf Coast in the fourth quarter of 2013 due to refining constraints. These discounts will persist due to the refining investment risk in the face of the crude export policy uncertainty that Gridlocks the market.
- A key uncertainty with the current export policy is whether and when refining capacity will be built to accommodate growth in production of LTO. There is currently substantial risk to building new refining capacity in the face of declining domestic gasoline demand (higher vehicle efficiency), regulatory and environmental permitting hurdles, unpredictable export product markets (competing international refining projects and market barriers to entry), and the US crude export policy (removing the crude discount). For this analysis, IHS has assumed price signals in the first five years result in rapid investments in substantial new simple topping capacity (an amount equal to 20-35% of the current US Gulf Coast refining capacity). If this capacity is not built as quickly as modeled in this analysis, a larger price discount would persist, resulting in a greater free trade benefits than modeled.

[53] Transportation fuels include gasoline, jet and diesel fuel.
[54] Annual average in real dollars over the period modelled (2016-2030).

INTRODUCTION

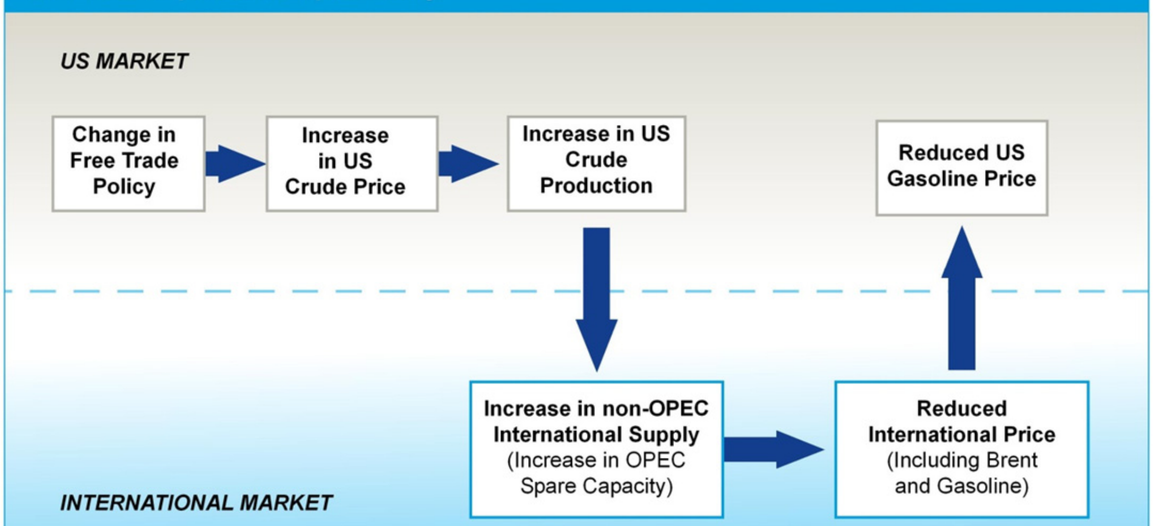
The rapidly increasing production of LTO is impacting crude and refined product prices both in the United States and internationally. This section provides an analysis of prices in three markets that are being affected by the growth in production: US light crude, international crude and US gasoline.

These three markets are individually distinct but interrelated through trade or the restriction of trade:

- **US Light Crude Price:** This analysis considers the impact of surging LTO production on the relationship between US crude oil prices and international crude oil prices. The section starts with a review of the historical price discounts observed between US and international crude oil prices over the past few years. The methodology and forecast results are then presented for this relationship between US and international prices, considered under both a free trade and restricted trade policy.
- **International Crude Price:** First, the IHS Brent price forecast underlying this study is presented. Next, the influence of additional US crude production on the global oil market is discussed, including an assessment of how free trade would lead to a lower price for international Brent crude.
- **US Gasoline Price:** An analysis of the US gasoline price is developed based on the results of the international market price response. This case shows that international crude and gasoline market prices have the most influence on US gasoline prices and not, as might be expected, domestic crude prices.

Based on our analyses of these three markets, free trade of crude oil is likely to result in a reduction in US gasoline prices. The relationship between trade policy and US and international prices is shown in Figure 4.1 below. Freeing US crude trade will lead to higher US crude prices and production while reducing both world crude and US gasoline prices.

FIGURE 4.1
US Price Response to Export Policy



Source: IHS Energy
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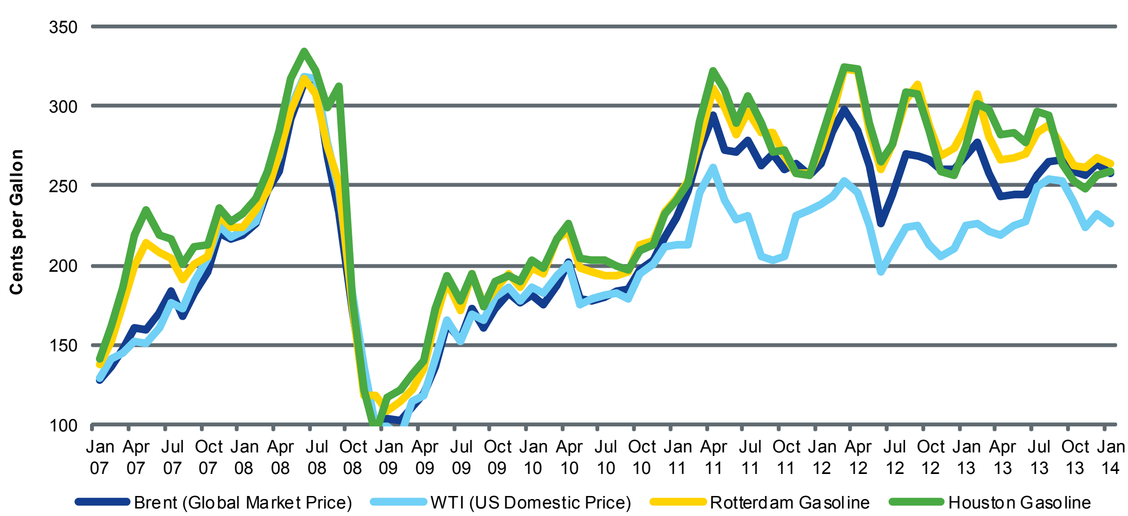
In freely traded markets, crude and refined product prices tend to move together. US gasoline prices, for example, are determined by international crude and international gasoline prices (Figure 4.2), because there are no US trade restrictions on the import and export of gasoline. But US trade in crude oil is restricted to the domestic market, which has caused notable differences between the US crude oil price and the global crude oil price.

The following section describes recent price divergences followed by how a change to free trade for US crude would reduce prices for crude traded on the international markets, translating into lower US gasoline prices.

FIGURE 4.2
Global Crude and Domestic Gasoline Price Tracking / Correlation



Source: Platts, IHS Energy

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US LIGHT CRUDE PRICE

After crude prices were deregulated in the early 1980s, US crude prices tracked closely with international prices. Indeed, the US crude oil benchmark (WTI) was typically priced slightly higher than Brent crude, the international price benchmark.

However, the price relationship between WTI and Brent has changed since 2010 because of the exceptional growth in US domestic crude oil production and the current restrictive crude oil export policy.

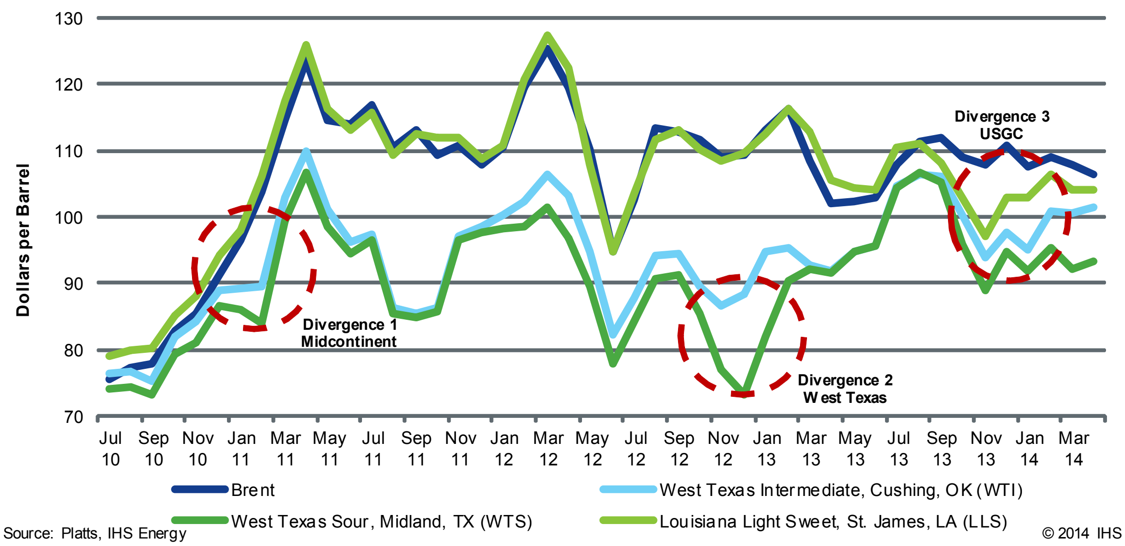
DIVERGENCES IN US CRUDE PRICE

Divergence One – Late 2010 / Early 2011 – The Great Revival Emerges

The price impact of the Great Revival in production of US inland crude oils emerged in December 2010. That period saw a divergence between prices for these inland crudes, which were declining, and for coastal and imported grades. Since the price for WTI is located inland at Cushing, Oklahoma, the WTI price discount was interpreted as a price discount for all US crude oils relative to the international market. However, grades produced in the Gulf Coast region (such as Light Louisiana Sweet (LLS) produced on the Louisiana coast) remained linked to higher-priced international benchmark grades. The initial Midcontinent crude oil price divergence was the result of logistics bottlenecks—there was insufficient pipeline capacity to move growing crude oil output from the Midcontinent/Cushing to the Gulf Coast.

In early 2011 and throughout 2012, the difference between the price of WTI Midcontinent crude oil and LLS Coastal crude oil widened to the point where it became necessary to move Midcontinent crude oils by rail car to a broader refining market since pipeline capacity was insufficient. The freight cost of moving crude oil by rail was roughly $10-15 per barrel. The divergence of a crude price in one region versus an adjacent region was symptomatic of the fundamental imbalance between demand and supply. When supply exceeds demand, the price falls to incentivize more demand, making it economic for refiners in other adjacent regions to process the crude and cover high freight costs.

FIGURE 4.3
Benchmark Crude Oil Prices



Source: Platts, IHS Energy

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Divergence Two – Late 2012 – The Great Revival Spreads to West Texas

In December 2012, a second domestic crude price divergence occurred, this time between prices for West Texas Sour (WTS), which is located in Midland, Texas, and prices in Cushing and on the Gulf Coast. This second price divergence, although short-lived, was another indication of the domestic crude market becoming increasingly oversupplied with light sweet crude oil. The price in West Texas was the result of a combination of inadequate pipeline capacity and seasonal maintenance of several West Texas refineries. The short-lived nature of the divergence was a function of the relatively rapid pace at which those refineries returned to full capacity.

During the first half of 2013, as pipeline capacity was added to connect Cushing to the Gulf Coast, the first price divergence—Divergence One—closed.[55] The price of inland crude oils was now reconnected to US coastal crude oils, and only small differences in price now existed, reflecting quality differences and pipeline logistic costs.

Divergence Three – Autumn 2013 – The Great Revival Reaches the World's Largest Refining Market, the US Gulf Coast

In October and November of 2013, a third price divergence occurred. This one impacted all domestically produced crude oils. This disconnect, resulting from a restrictive export policy, signaled the potential for deeper and long-lasting price disconnects. This restrictive export policy means there are no more market outlets for higher US crude production, except at prices that would endanger the revival of US crude oil production.

[55] In the form of reversing the Seaway pipeline system so that it runs from north to south.

GRIDLOCK FROM INCREASED LIGHT TIGHT OIL

Continued growth in US production will drive deeper crude oil discounts (though not gasoline discounts), as less and less efficient refinery processing tiers are breached in an effort to process more and more LTO. The inability to export light crude oil creates an LTO price discount that provides a clear price signal for investments that is negative for producers and positive for refiners. The result is that refiners see significant risk in the form of potentially stranded investments if the export policy were to change, while producers see a risk that refiners will not invest and that prices will decline further. This market dynamic, which IHS terms Gridlock, effectively acts like a traffic jam.

Gridlock is driven not only by price signals between the US upstream and downstream industries, but also by a heightened degree of uncertainty about future crude oil trade policy. This means investment to relieve system congestions will be slower in coming years, compared with a business environment of greater confidence about present and future policies.

Uncertainty about future US crude export policy exacerbates this Gridlock. Deeply discounted crude (well below the level of LTO price advantage from free trade) will significantly reduce the amount of capital that upstream participants will invest in additional drilling and production, eventually negatively affecting both US economic growth and production. Initially, some downstream participants have responded to the domestic crude discount and available export markets by adding select simple topping capacity. But they also have to recognize that a change in export policy could strand investments of this type. The United States will continue to import large quantities of heavy crude oil, but a liberalization of oil exports would allow crude to efficiently move to the highest-value markets, unlocking the Gridlock while providing greater benefits to the US economy and consumers.

PRICE RESPONSE: 2014 – 2030

Price Response Methodology

For most people, the price of crude is what is shown in the morning paper or on the market news shows. However, as outlined previously, there are important differences among crude oil grades within the oil industry, particularly when they flow into the downstream refining sector. The LTO price discounts observed in recent years and projected to occur over the coming years can be explained by two primary factors: 1) refining economics and 2) discounts due to market volatility during periods of market oversupply.

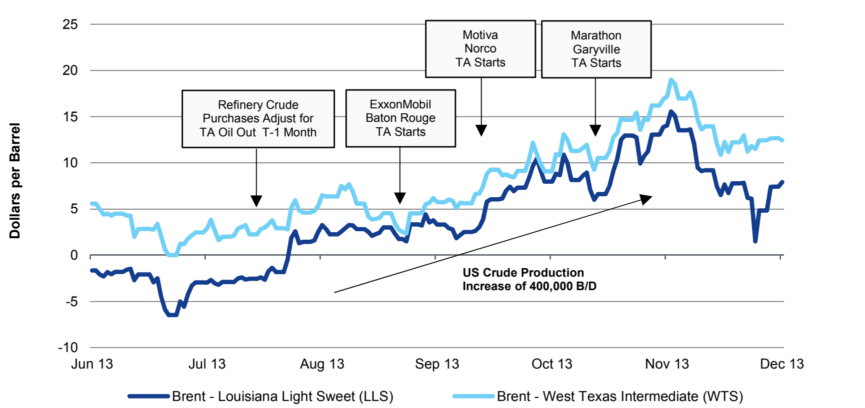
Refining economics focuses on the profit difference a refinery realizes when substituting one crude oil for another, or in this case, when substituting imported crude of a given quality with higher-priced domestic LTO. In some cases, the reduction in profits from this substitution can be quite large. This profit impact can be used to estimate the LTO price discount, which is defined as the price relative to an alternative crude oil. To calculate this LTO discount, IHS uses a series of refinery models to estimate the profitability of processing crude oils in different refinery capacities (configurations). A brief description of refinery displacement economics is shown in Figure 4.5 and was previously discussed in Section III.

The seasonal discount is more challenging to quantify but can also be estimated based on historical market behavior and expected seasonal changes in supply and demand. One such period is described previously in the text box, “Has Crude Oil Gridlock Already Occurred?”

HAS CRUDE OIL GRIDLOCK ALREADY OCCURRED?

The US oil system still has several outlets for placing LTO before full crude oil Gridlock occurs. But in late 2013, crude price differentials suggested that producers can experience much lower prices well before all outlets are fully utilized. Since 2010, the WTI crude price at Cushing has had periodic, and at times very sharp, price dislocations from global markets. These dislocations were caused by increased volumes of US and Canadian crude moving into the Cushing storage hub, creating a surplus of crude as the hub contended with insufficient takeaway capacity. The US Gulf Coast, which lacked sufficient connectivity during this period, did not experience the discounts seen at Cushing and further upstream. Additional pipelines have been added to increase the connectivity between the Cushing hub and large refining centers on the US Gulf Coast. In mid-2013, large new pipelines began filling and flowing.

FIGURE 4.4
Refinery Outages vs Crude Differentials



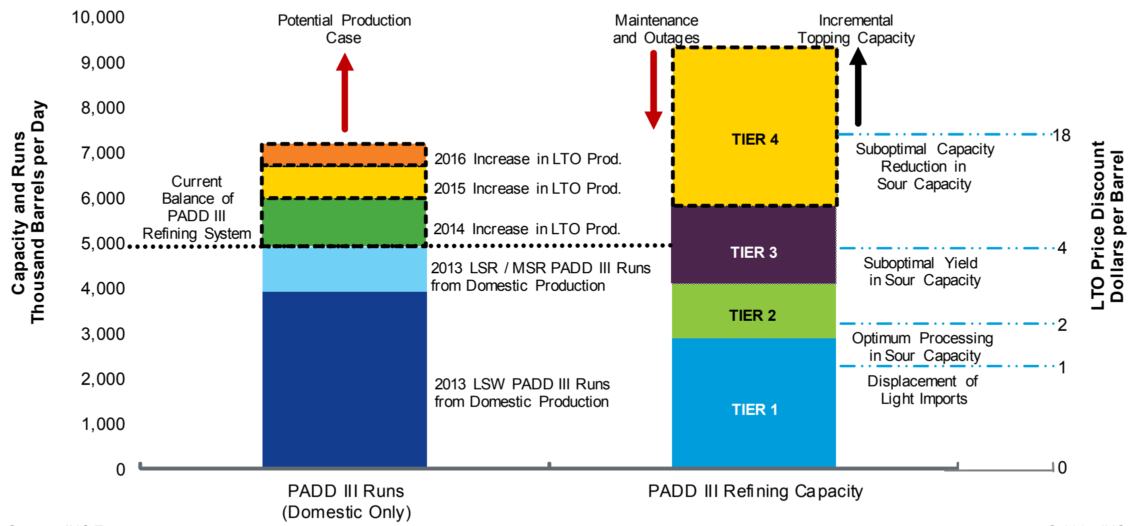
Source: IHS Energy, Platts | Note: TA = Turn Around | © 2014 IHS

As these additional pipelines physically linked the US Gulf Coast crudes to the WTI hub, a price correlation has been maintained since early September 2013. But this physical connectivity, combined with the increased production also revealed that the market was temporarily oversupplied in light sweet crude oil as refiners entered the fall maintenance period, temporarily reducing crude oil demand. When domestic light sweet crude prices began to disconnect from global markets in early September 2013, the Gulf Coast crude markets followed the WTI benchmark down, with discounts for LLS as low as $15 a barrel relative to Brent prices. As refiners came back from maintenance and the excess inventory of light sweet crude was reduced, prices reverted to a much smaller, but still historically large, discount.

This highlights that the current difference between a balanced and imbalanced light sweet market could be as small as 500,000 B/D. What will matter increasingly going forward is not just that some of the Gulf Coast refineries are entering maintenance season, but which refineries are scheduled for maintenance. The shutdown of just one or two refineries or crude trains that are properly configured for LTO could have a disproportionate price response, as displaced LTO volumes are forced to be processed in ill-configured capacity (and no ability to export). To absorb the capacity during maintenance, the entire US crude market could move into the next Tier.* This seasonal issue for US producers is expected to be exacerbated with each subsequent refining maintenance season as LTO production increases. It certainly can become more acute during the 2014 maintenance season when production of LTO increases by 1 million B/D. The typical interval between planned refinery maintenance downtimes is 4-5 years, and the downtime typically lasts 6-8 weeks. Using these two inputs, on average 3.3% of US refining capacity can expected to be offline on a structural basis.** However, most refiners concentrate maintenance in the winter and fall to avoid the higher demand associated with the summer driving season. This can result in 5-10% of US refining capacity being offline during a typical maintenance season. For the US Gulf Coast, 5% of capacity equates to 460,000 B/D of capacity offline, and is enough to move the market from the Tier 3 to Tier 4 pricing environment. It is possible that this market dynamic could become a biannual fixture of the market.

* Moving from Tier 3 (LTO into medium sour, suboptimal yield) into Tier 4 (LTO into medium sour, throughput reduction).
** One refinery downtime every five years equals 20% of the US refining capacity down annually for a period of two months or 16.7% of the year; 20% x 16.7% = 3.3%

FIGURE 4.5
US Gulf Coast Refinery Processing Tiers and Corresponding LTO Discount



Source: IHS Energy

Crude oil refining is a manufacturing process with a different profit and risk profile than crude oil exploration and production. To maximize profits, refineries seek to select the optimal mix of crude oils and products. Crude producers, on the other hand, take on large discovery and exploration risks to determine whether the resource is available and can be extracted economically. Once producing, the field economics are in large part dependent on the market crude price. Unlike the upstream producing sector that relies on the overall crude price, the primary driver of downstream refining economics is the margin available between the prices for crude oil and for the products that can be produced with the hardware (configuration) available. These margins are typically relatively small—a few dollars per barrel of crude throughput.

The refiner is subjected to market margin risk, which can be quite volatile; however, there is only modest operational risk that the crude oil will not be converted into the intended products. While profit margins are relatively small, crude throughput at a typical refinery is large (on the order of 200,000-600,000 B/D (compared to 1,000 B/D for a typical Bakken well, for example). As a result, refiners have developed sophisticated models (linear-program or LP models) to optimize the available crude slate (the mix of crude oils processed) and associated products that can be produced in the refinery.

Results for Free Trade Cases

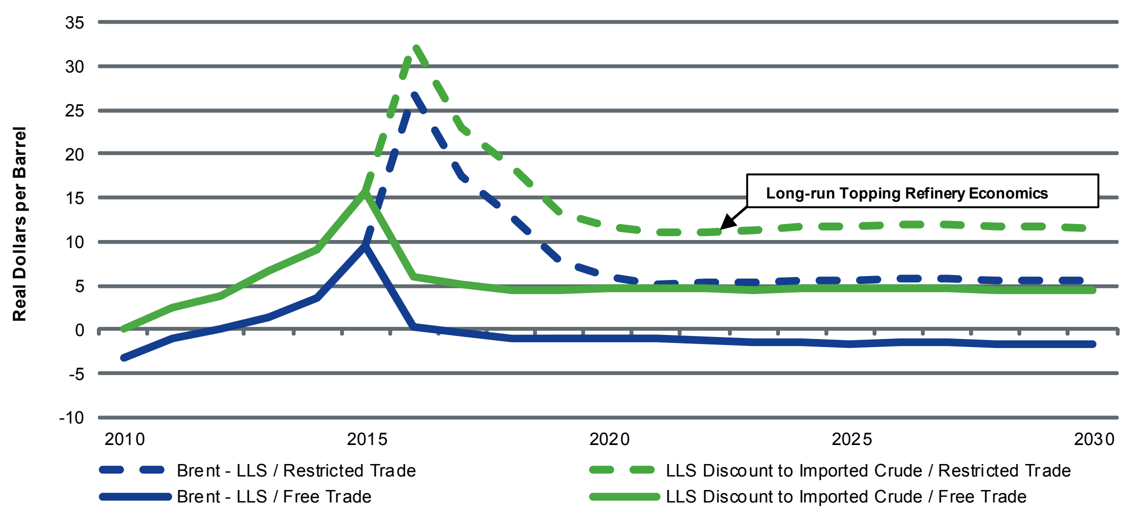
As additional domestic crude is produced over the next few years, LTO discounts are expected to become larger and larger. In both of the Production Cases with free trade, the average 2015 discount of domestic crudes (LLS) to international crudes (Brent) is modeled at $10 per barrel with continued restricted trade. This price difference is larger near the end of the year and during certain months when refineries are shut down for maintenance (Figure 4.6).[56] The LTO balance suggests that sour crude refiners will be operating in a Tier 3 LTO price discount (refining LTO into medium sour at a suboptimal yield) during most of 2015 but during four months of the year will push into a Tier 4 LTO discount (refining LTO into medium sour, with reduced throughput). The assumption for both Production Cases is that the free trade of crude oil is allowed beginning in January 2016. At that point, the price discount is expected to decline rapidly as crude oil cargos are exported from the United States and additional sour crude oil is imported, allowing the

[56] The Brent-LLS spread is forecasted at $17 per barrel in the 4th quarter of 2015.

refining systems to move from suboptimal to optimal operation. In both cases, the LTO price reestablishes a new equilibrium based on export markets in Europe and Asia, placing US Gulf Coast crude oil (LLS) near or just below Brent on a freight on board (FOB) price basis.

It is important to note that when LTO free trade is modeled in both production cases, the price for domestically produced LTO will still be competitively priced to both imported crude oils and to historical price relationships with Brent. This price, on the order of $5 per barrel lower versus imported crude after accounting for quality and freight (marine tanker to and from the international market), will provide domestic refiners a continued competitive advantage in international markets for their products. This LTO price is important to refining competitiveness but much less severe than the LTO discounts expected under the restricted trade policy. The lower priced US natural gas is a further benefit to refiners.[57]

FIGURE 4.6
Domestic Light Crude Price Discount for Base Production Case



Source: IHS Energy, Platts Note: LLS = Louisiana Light Sweet (St. James, LA) © 2014 IHS

Markets for US Crude Exports

Latin America and Europe are logical export markets for US light sweet including LTO. [58]

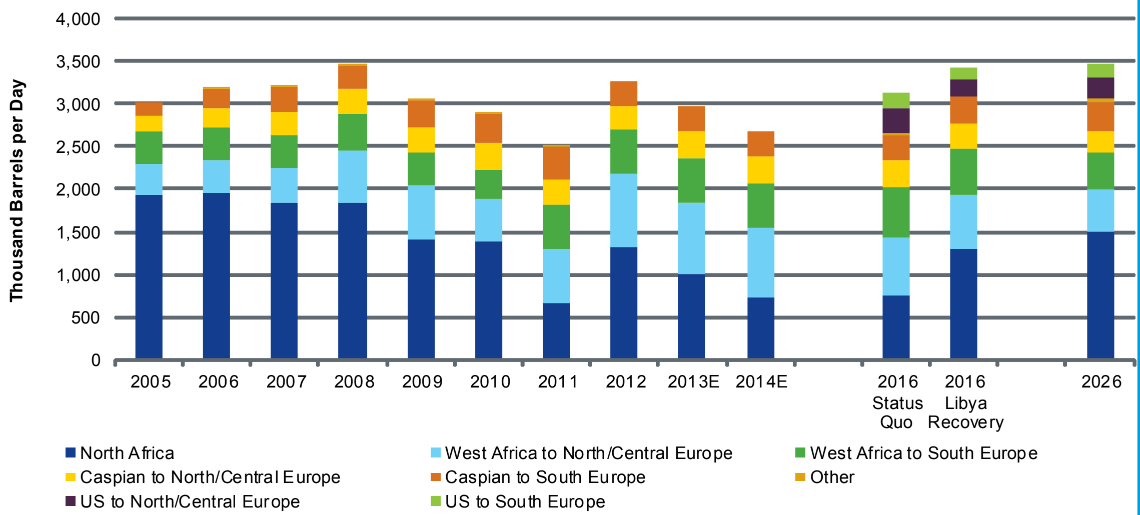
Latin America currently imports less than 300,000 B/D of light sweet crude, mostly from West Africa. A portion of this trade could be displaced by US crude oil, diverting the African shipments to Asia's rapidly growing market. US exports to Latin America are likely to be modest relative to the overall projected export volumes.

In Europe, declining crude production from the North Sea fields has increased light sweet crude imports from other regions to around 3 million B/D. This import volume has varied in the past few years due to production losses from Libya. Figure 4.7 provides Europe's historical light sweet crude imports from major exporting regions, along with projections of how US exports, if permitted, could be expected to shift the balance in 2016 and 2026.

[57] Energy costs are a primary refinery expense, with natural gas and electricity typically representing 30-40% of the variable operating costs. The difference between $5 per MMBTU natural gas and $10 per MMBTU natural gas represents a difference of $0.50-1.00 per barrel in variable operating costs.
[58] Latin America includes Mexico in this analysis.

Of the current supplies to Europe, West African imports are most likely to be displaced to Asia by US crude oil exports. Some of the Caspian trade to northwestern Europe could be expected to be replaced by US crude oil exports as well. In addition, some Russian crude exports to Europe could be displaced by US crude. Much of northwest Europe's refining capacity was originally designed for North Sea light sweet crude oil, which has since declined in production. North Sea crude has been replaced with both sweet and sour crude oil imports—about half from Russia (Europe now imports approximately 4 million B/D of Russian Urals grades, primarily light sour). Due to historical configuration and crude slate, European refineries possess the ability to economically substitute US light sweet crude grades for light sour crude oil.

FIGURE 4.7
Light Sweet Crude Imports to Europe



Source: IHS Energy Note: Does not include potential Russian light sour crude displacement. © 2014 IHS

The remaining US exports are expected to be shipped to Asia, where there is a large and growing appetite for all grades of crude oil. The Asia-Pacific market currently imports over 9 million B/D of crude oil, of which nearly 2 million B/D is of light sweet quality. Total Asian imports are also forecast to increase to 12-13 million B/D by 2030. Further, because new refining capacity is being built in the region—around 600,000 thousand B/D is added per year—to meet growing demand from the developing economies, there is little constraint in processing additional light sweet crude.

In sum, in a free trade policy environment, forecasts of exports (excluding exports to Canada) grow to peaks of 1.4 million B/D in the Base Case and 3.6 million B/D in the Potential Production Case.

Analysis Results with Restricted Trade

In the restricted trade policy environment, the LTO discount to world crude prices is projected to increase sharply in 2016 as production continues to rise and refiners require large discounts to process even more LTO. Pricing moves into a Tier 4 LTO price discount, with reduced sour crude runs to accommodate the refining of LTO with no other place to go. With continued restricted trade, there is an assumed shift in market sentiment towards an acknowledgement among crude buyers and sellers that the current export policy will persist for some time. As discounts widen in 2015 and 2016, the refining industry will respond by adding LTO refining capacity to capture the increasing arbitrage between the discounted domestic LTO and international refined products and refinery unfinished intermediates, such as naphtha and vacuum gasoil.

In the restricted trade situation, the US refining industry is expected to respond to this domestic-international arbitrage. Severe price discounts could be expected to dissipate over a few years as new capacity is added to process LTO. By 2020, a new equilibrium is achieved based on refinery topping economics.

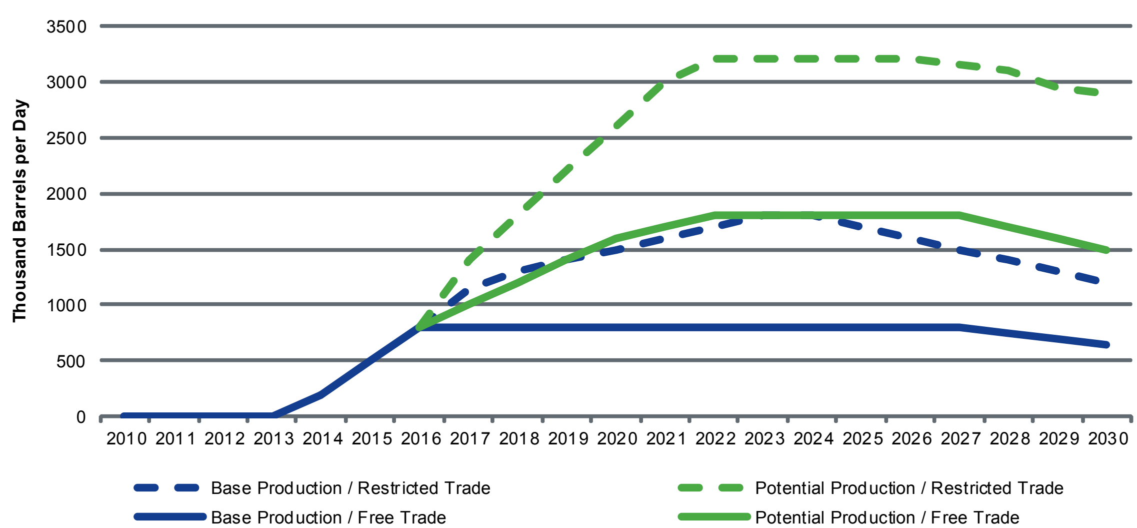
Refining Reaction - Topping Capacity Additions

The US refining industry is expected to build simple topping capacity rather than full conversion refineries, which produce all clean light products (gasoline, jet and diesel fuel). Due to its simplicity, a topping refinery or unit, also known as a splitter, can be constructed more quickly (2-3 years versus 5-6 years for full conversion) and at a much lower cost (approximately $1 billion versus $5 billion).[59]

Topping units are the simplest refining configuration, and little of this type of capacity is located in the United States because the economics are usually poor. However, topping units can be profitable if trade is restricted and a domestic-international oil price arbitrage remains as expected under a restrictive trade policy. These refineries cannot produce gasoline and produce only limited amounts of finished products (liquefied petroleum gas and jet fuel) and would need to export unfinished intermediate products for further refining. While the European refining industry is a substantial importer of intermediates, it is likely that, after a few years, trade of lower quality unfinished products from US topping refineries would need to be shipped to Asia to clear the market. As a result, an Asian pricing basis is used for the longer term crude discount forecast past 2020.

Some new topping plants have been announced to process condensate, and similar units are being constructed inside a few refineries. More could be built, although the speed at which permits and construction can be completed is uncertain and could be a drag. Consistent with recent construction, this analysis assumed that a new moderate-sized unit can be built in 24 months. Another risk, however, is a tightening market for skilled labor, as new manufacturing capacity is built in the US Gulf region to take advantage of low natural gas prices. This could drive up costs of building topping plants or extend construction periods.

FIGURE 4.8
Incremental US Topping Capacity Needed For Each Production Case and Trade Scenario



Source: IHS Energy

© 2014 IHS

[59] Based on a 200,000 B/D refinery.

A key risk of building these plants is that their viability relies solely on US crude export policy. The plants would not be profitable in a free trade market, so a policy change would most likely put simple topping units out of business. While $500 million is much less than $5 billion, it is still a significant sum of money; and potential investors would be concerned about that risk and thus some would be cautious about committing to such a project. To account for this high risk, the long term LTO price discount under restricted trade includes a two-year payout on a newly built topping refinery units. This equates to an LLS price that is about $5 per barrel below Brent.

In summary, there is considerable uncertainty about permitting, constructing and commissioning the 1.8-3.2 million B/D of new topping capacity that would be needed to absorb LTO production with restricted trade. That would be a 20-35% increase from the current US Gulf Coast refining capacity, in the Base and Potential Production Cases respectively. If this capacity is not built, larger price discounts would occur putting more pressure on new upstream investment.

INTERNATIONAL CRUDE PRICE

This study uses the IHS Brent crude price forecast for the Base Production Case that assumes the free trade of crude oil in 2016. In the world oil market, the Brent price represents the global benchmark price used to establish other crude oil and crude oil-related prices. A description is provided below for the IHS Brent crude price as it relates to this analysis. The change in the Brent price forecast caused by changes in US production and export policy is also discussed below.

IHS INTERNATIONAL CRUDE OIL PRICE FORECAST

Over the long term, as world demand for crude continues to grow and conventional reserves decline, more supplies will be needed from high-cost sources, such as deepwater, ultra-deepwater, extra-heavy oil—including the Canadian oil sands—and from plays in other more demanding environments and marginal fields. While growth in US LTO production will be an important supplier to global oil markets over the coming years, other supply will also be required to meet demand. Various factors, including rising project costs, suggest that non-OPEC output growth, outside of North America, will slow and skew toward more expensive, harder-to-produce reserves. As this happens around 2020 in our forecast, the real dollar Brent price rises to approximately $120 per barrel, the price level necessary to develop these more challenging resources.

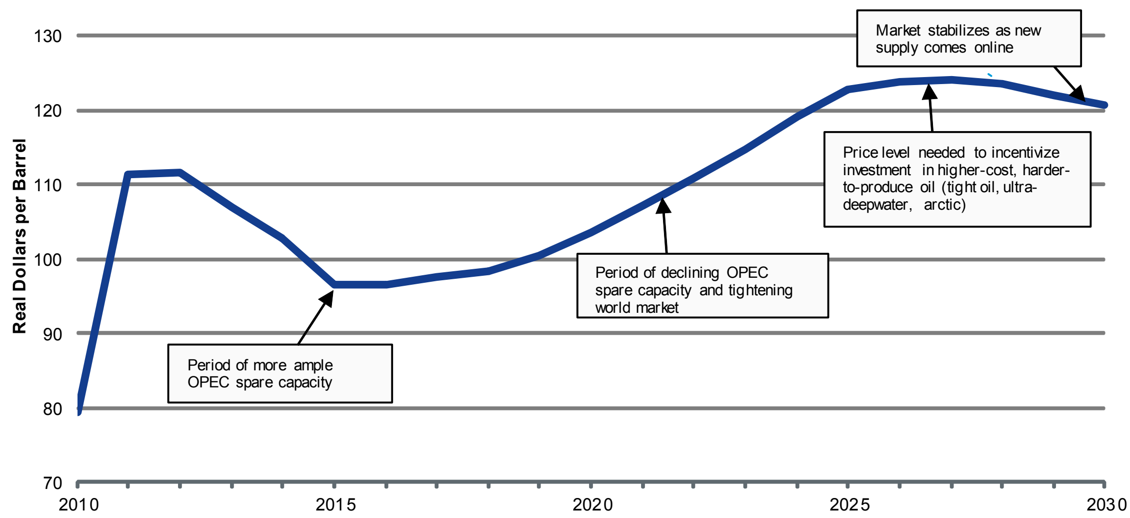
Very large potential for tight oil also exists outside of North America. IHS has identified the 23 most promising prospects.[60] But development of tight oil in other regions is expected to occur at a much slower pace and be more expensive due to a host of above-ground factors.

BRENT CRUDE PRICE FORECAST

Despite relatively weak global economic growth since the Great Recession, international crude oil prices, as represented by Brent, have remained near $110 per barrel for the past three years. IHS' analysis of crude supply, product demand and production cost trends supports the view that prices will be at these levels in the longer term (Figure 4.9). In the meantime, however, Brent is projected to decline moderately over the next several years in the free trade Base Case as additional non-OPEC crude supplies enter the market, notably from the United States and Canada.

[60] Going Global: Predicting the Next Tight Oil Revolution, IHS 2013.

FIGURE 4.9
IHS Base Production / Free Trade Brent Crude Price



Source: IHS Energy, Platts

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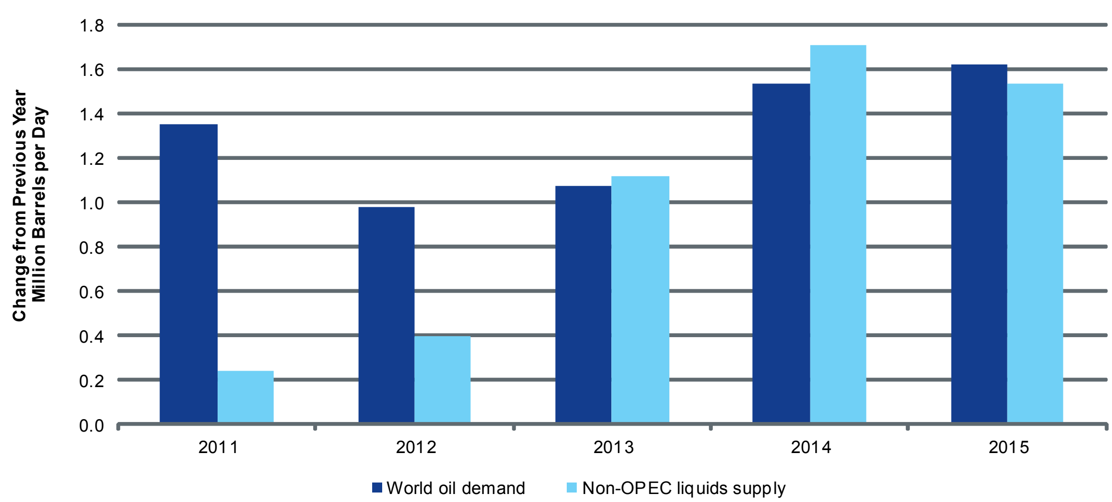
Over the next two years, growth in non-OPEC liquids supplies, driven by North American supplies of tight oil, oil sands and NGLs, is expected to meet—or come close to meeting—all global demand growth, making the call on OPEC flat (Figure 4.10).[61] As this occurs, the Brent price is projected to weaken to slightly less than $100 per barrel in real dollar terms before increasing back above $110 per barrel in the longer term.

FIGURE 4.10
World Oil Supply and Demand Changes, 2011 - 2015



Source: IHS Energy

Note: Liquids supply includes crude, condensate, and natural gas liquids (NGLs).
Demand includes refined products, including liquefied petroleum gases (LPG)

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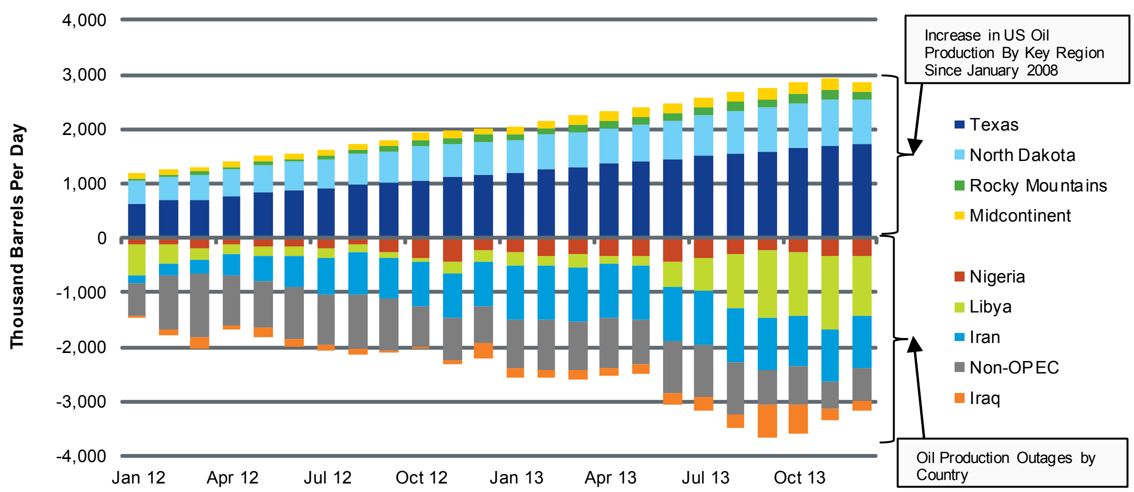
[61] The “call” on OPEC refers to the necessary OPEC crude oil production level to satisfy global demand.

US production has already had an impact on world markets. Over the past three years—coinciding with a period of very strong increases in US and Canadian oil production—there have been significant production outages in key crude supplying countries outside of North America. Today, roughly 3 million B/D of production is off the market due to various production issues. These include Western sanctions that have reduced Iranian oil exports, civil disruption and political blockades of Libyan oil, and wars in Syria, Yemen, Sudan and South Sudan. In countries where significant volumes of new supply had been anticipated, including Iraq and Brazil, actual outputs has fallen short of initial expectations. Meanwhile, between 2008 and March 2014, US production on an annual basis has grown by 3.2 million B/D—an increase of 64%. The offset provided by rising US production is illustrated in Figure 4.11 All else being equal, the increase in US LTO supply has kept oil prices from rising much higher.

FIGURE 4.11
US Production Growth Offsetting Global Market Disruptions



Source: IHS Energy, EIA

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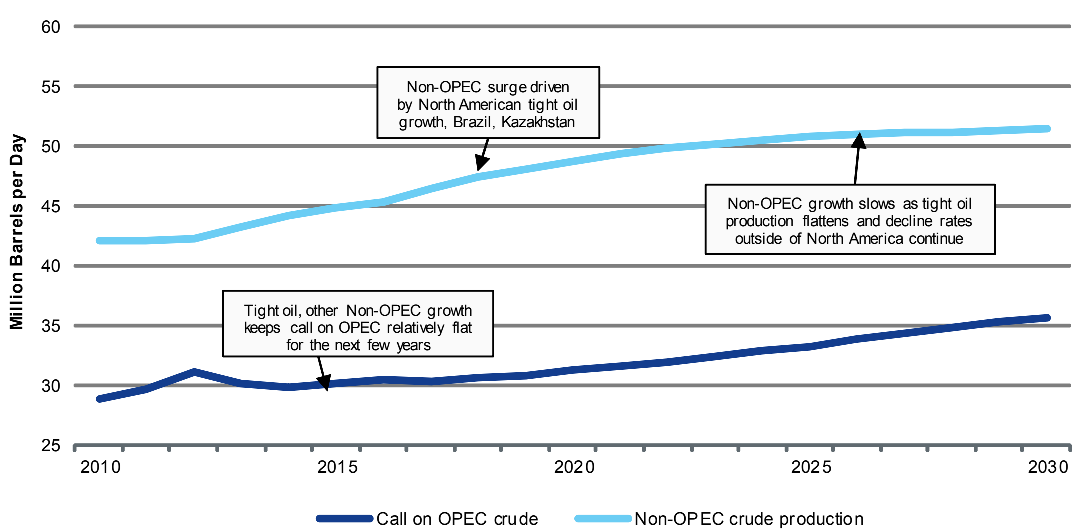
FIGURE 4.12
OPEC and Non-OPEC Crude Production



Source: IHS Energy

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From now through about 2020, growth in US LTO combined with other non-OPEC supplies is forecast to keep the call on OPEC relatively flat (Figure 4.12). After this period, non-OPEC supply growth is forecast to slow (consistent with the Base Production Case). As this occurs, more crude production will be needed from OPEC countries, and the call on OPEC crude supply is forecast to increase to meet global demand.

INFLUENCE OF US CRUDE PRODUCTION ON THE BRENT PRICE

While US crude is currently not exported, except to Canada, the growth in US crude supplies have, nevertheless, influenced global oil markets by reducing US crude imports, which have been displaced to other world markets. Going forward, US production will continue to have a role in global oil prices. However, the degree of influence will be directly related to the level of production that is achieved, which in turn is related to export policy.

IHS estimates US export policy will have a notable impact on the US crude production volume, as presented in Section II, due to the degree of domestic crude price discounting and associated drilling activity. The changes in US production among the cases considered is substantial enough to influence global crude oil prices over the entire period evaluated, through 2030.

While global oil markets and pricing are multifaceted and challenging to project, the level of spare production capacity—held by Gulf OPEC members—is a key factor affecting oil price trends. Typically, non-OPEC producers operate at full capacity and do not make production changes if crude prices remain above their operating costs.

OPEC, and specifically Saudi Arabia, adjusts supply to meet global demand. By increasing or decreasing supply, OPEC's actions affect world oil prices. Therefore, the level of spare OPEC capacity is a key variable that measures how tight or loose the balance is between global production and potential global production. Spare capacity represents the available supply cushion to accommodate unexpected events such as production outages or surges in demand. When other supplies of crude are added or removed from the market, OPEC adjusts its spare capacity accordingly. In this way, the Great Revival in US oil production has led to a higher spare OPEC capacity and a lower global oil price than would otherwise have been the case.

The Libyan revolution in early 2011 is one instance in which the Brent crude price responded to a supply loss and reduction in OPEC spare capacity. This event removed about 1.2 million B/D of light crude oil from the market in two months. Saudi Arabia and other OPEC producers responded by increasing output, but this reduced OPEC's spare capacity. Brent and world crude prices responded immediately, rising from less than a $100 to over $120 per barrel between January and March 2011 before falling back to about $110 per barrel a few months later (Figure 4.13).

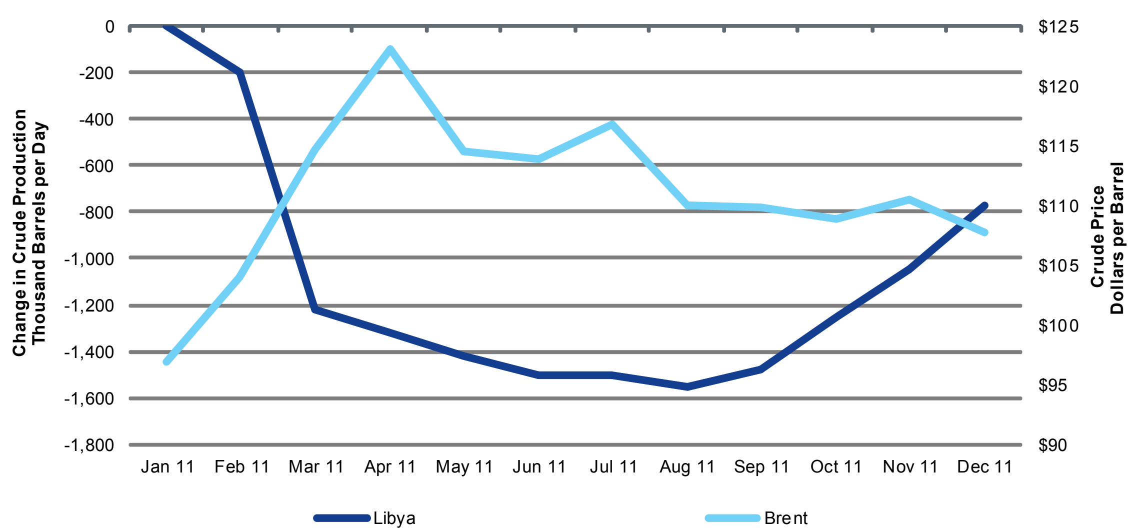
Other examples of changes in supply and price are provided in Table 4.1. In each case, adding or removing supply that is not part of OPEC's spare capacity caused a notable price response.

TABLE 4.1
Recent Crude Oil Supply-Demand Disruptions and Corresponding Crude Oil and Gasoline Price Reponses

Event	Dates	Physical impact (thousand barrels per day)	Brent Price Change (dollars per barrel)	US Retail Gasoline Price Change (dollars per gallon)
Libya Production Fall Libyan Production Offline due to Civil War	Jan 2011 - Jul 2011	1.5 Million B/D Production Decline	$19.8	$0.62
Replacing Libya Production Saudi and other Core GCC OPEC Members Make up for Offline Libya Production	Jun 2011 - Jul 2012	GCC OPEC Core + Libya Production Rises 2.3 Million B/D	-$18.0	-$0.24
Iran Sanctions (Europe) Sanctions Cut Iranian oil Exports to Europe	Jan 2012 - Apr 2012	0.7 Million B/D Export Reduction	$9.0	$0.18
Iran Sanctions (US) Sanction cut Iranian Oil Exports to Largely Asian	Jun 2012 - Aug 2012	0.8 Million Export Reduction	$17.0	$0.52
Absolute Average of 4 Events		1.3 Million B/D	$16 Crude Price Response	$0.39 Gasoline Price Response

Note: GCC = Gulf Cooperation Council
Source: IHS Energy

FIGURE 4.13
Libya Crude Production and Brent Crude Price



Source: IHS Energy, Platts

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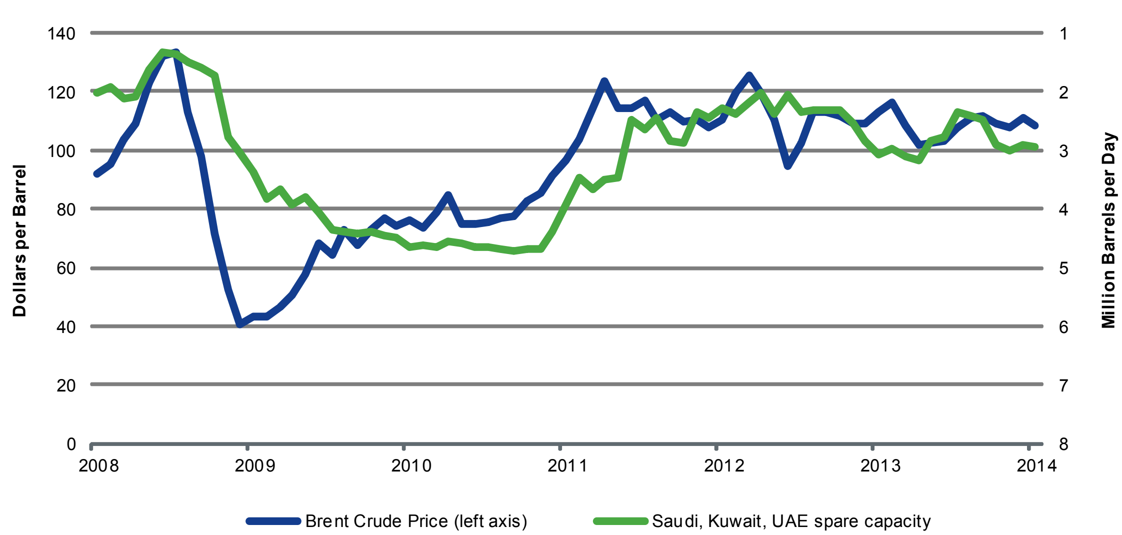
To be sure, numerous forces influence the price of oil, but the level of spare capacity is key. Spare capacity represents the net impact of supply and demand changes around the world. The relationship between OPEC spare capacity and the Brent crude price is reasonably reliable considering the complexity and geopolitical nature of oil.[62] (Figure 4.14) This fundamental economic principle is considered in when estimating the Brent price response from additional US production.

FIGURE 4.14
Sustainable OPEC Spare Capacity



Source: IHS Energy, Platts

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[62] In this analysis, OPEC spare capacity assumed as the total of Saudi Arabia, Kuwait and the U.A.E.

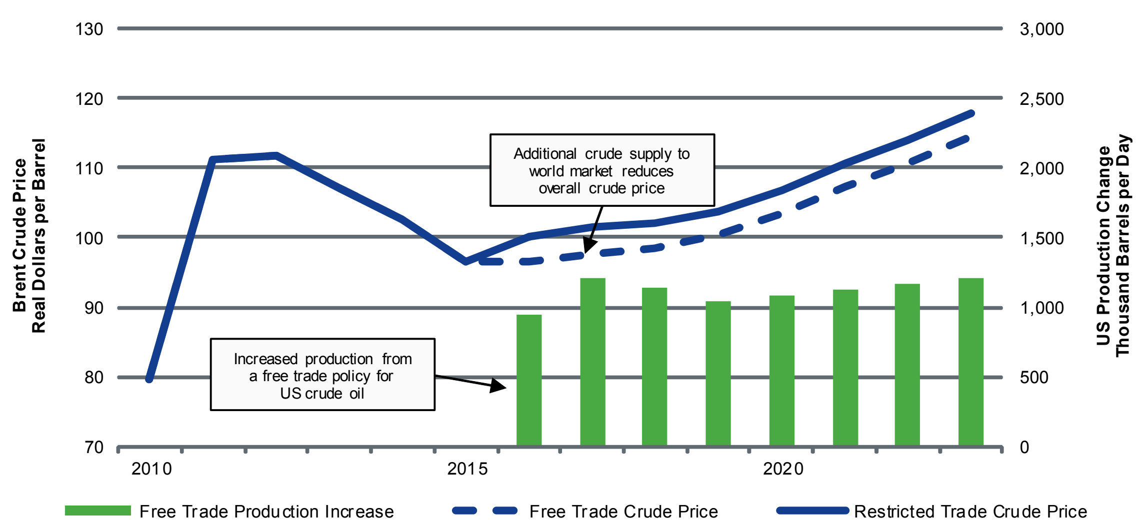
WHY GASOLINE PRICES DECLINE WITH FREE TRADE

So what is the mechanism by which gasoline prices will decline if the free trade of US crude oil is allowed? As will be shown later in this section, the global price of crude (Brent) is a key determinant of US gasoline prices. Therefore, US crude production growth from free trade is important. If growing production causes OPEC's spare capacity to rise, Brent and US gasoline price can be expected to decline.

US and other non-OPEC production growth will have a notable influence on Brent and world oil prices. Therefore, differences in the growth of US crude production in each of the Production Cases and corresponding trade policy environments could be expected to affect the Brent price. For this analysis, it is important focus on how additional US crude supplies in a free-trade environment might affect world oil markets and the Brent price, compared with Brent prices under the current restricted trade policy.

Free trade in both Base and Potential Production Cases takes into account the additional crude supply and resulting reduced prices for Brent and other global crude oils. In Figure 4.15, the additional production realized with free trade relative to restricted trade is shown along with the expected Brent price response in the Base Production forecast. The price impact from additional supply is projected to be slightly greater than $3 per barrel in real dollar terms on average for the 2016 through 2030 period.

FIGURE 4.15
International Crude Price Response to Free Trade for Base Production Case



Source: IHS Energy, Platts

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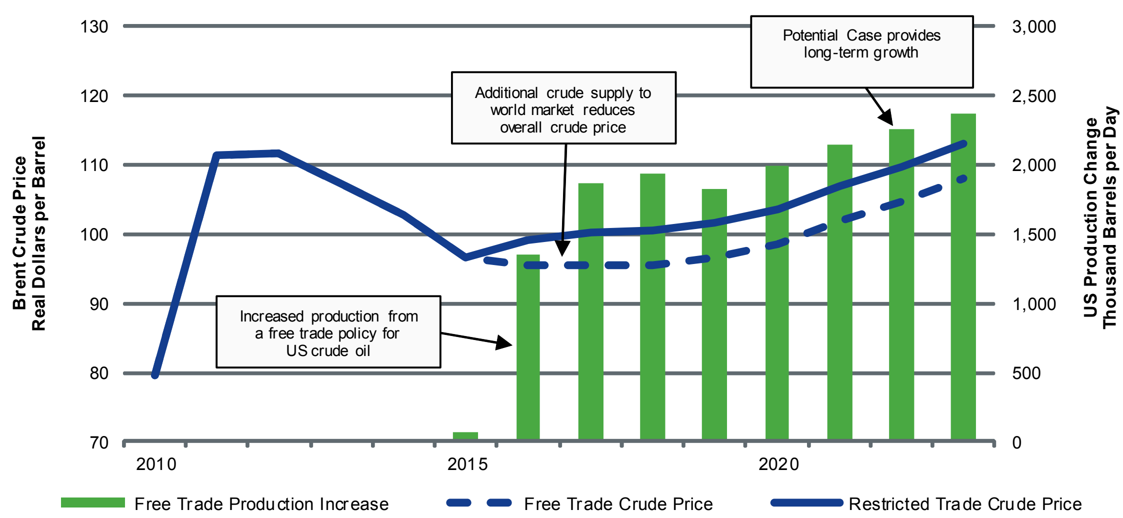
The price response in the Potential Production Case (Figure 4.16) is estimated to be larger and provides an increased benefit as compared to the Base Production Case. In the Potential Production Case, the additional production associated with free trade, as compared to restricted trade, is approximately twice as much as in the Base Production Case. With this additional production from free trade, the Brent price is by approximately $5 per barrel on average in real dollar terms over the forecast period.

FIGURE 4.16
International Crude Price Response to Free Trade for Potential Production Case



Source: IHS Energy, Platts

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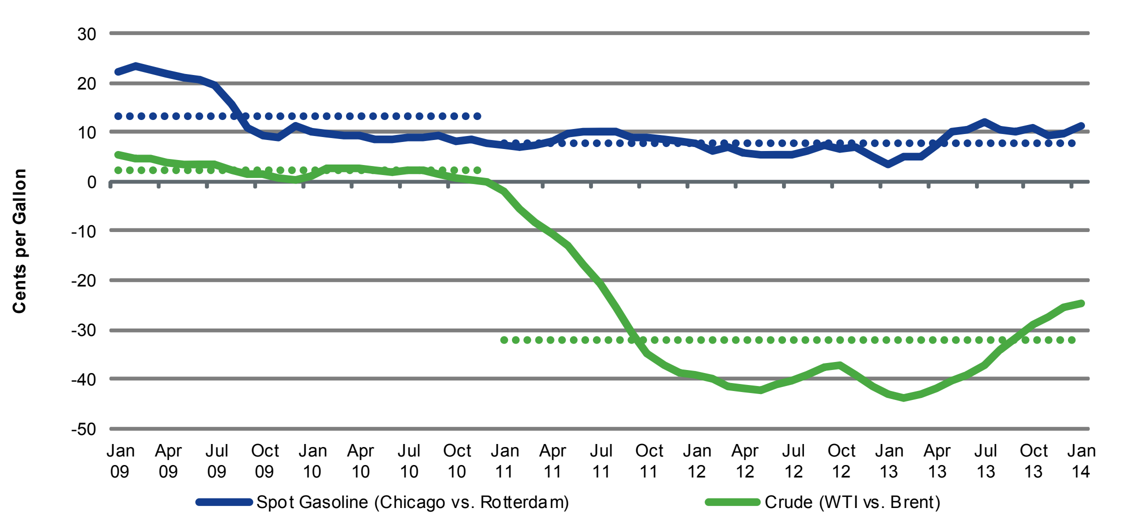
US GASOLINE PRICE

It may seem a reasonable assumption that liberalizing crude oil export trade will lead to higher US gasoline prices. However, crude and gasoline pricing data do not support this conclusion. Rather, the data make clear that international market prices—and not domestic crude prices—have more influence on US gasoline prices. Gasoline and other refined products are not subject to the same trade restrictions as crude, and both imports (to the East Coast) and exports (from the Gulf Coast) routinely are freely traded. This free trade and movement of refined products create price linkages among markets both inside the United States and between the United States and foreign markets. These product price linkages have remained firmly in place despite significant changes in the price of the crude refined within domestic market.

FIGURE 4.17
US Midwest Gasoline and Crude Price Relative to International Price



Note: Dotted lines represent the averages
Source: Platts, IHS Energy

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A key example of these interregional US product price relationships is provided by the events that occurred in the Midcontinent market beginning in early 2011 (i.e., Divergence One). As prices for WTI in Cushing, Oklahoma and for other Midcontinent crudes weakened dramatically relative to Brent, the price of gasoline and other refined products in the benchmark Chicago market retained their historical price relationships with international markets, such as the Rotterdam (Europe's benchmark) gasoline market. As shown later in the section, the independence of US gasoline from domestic crude prices is prevalent in all of the major US gasoline markets. In fact, singular events such as multiple refinery outages creating imbalances in gasoline supply and demand have had a far bigger impact on inland gasoline prices than the change in the WTI price relative to Brent. Thus, were crude exports to be liberalized—strengthening the price of US crude—US gasoline prices would not increase. Instead, they would maintain the same relationship with global gasoline prices as they did before—and during—the inland crude discount period.

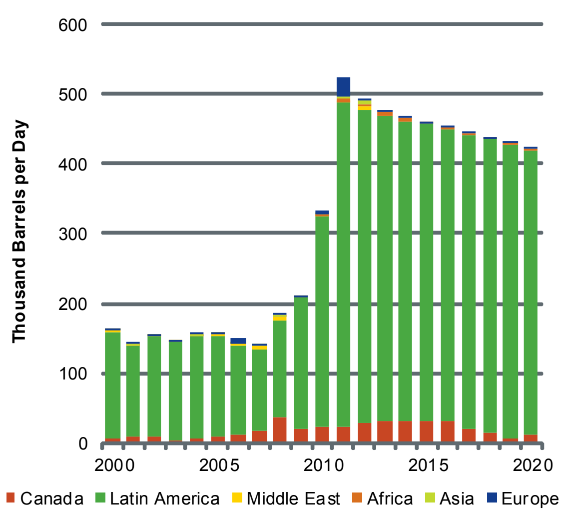
US PRODUCT FLOWS – INTERNATIONAL LINKAGES

Foreign Product Trade

US Gulf Coast refineries have recently benefited from access to discounted crude and inexpensive natural gas.

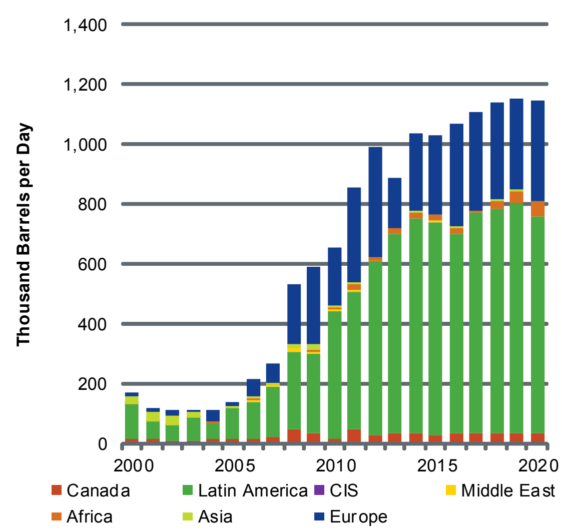
Natural gas is an important and substantial input in the refining process, both as a fuel to heat the oil and as a feedstock to produce the hydrogen that aids in removing sulfur from products. Due to low-cost shale gas production, US natural gas prices are far below those in Europe and Asia, keeping both refinery energy and hydrogen production costs low. Now, with US crude prices also advantaged, Gulf Coast refineries benefit from cheaper feedstock as well. Lower-cost feedstock, coupled with the size and sophistication advantages of Gulf Coast refineries, have allowed them to operate at high utilization levels and increase their product exports, as shown in Figures 4.18 and 4.19.

FIGURE 4.18
US Gasoline Exports



Source: IHS Energy, EIA © 2014 IHS

FIGURE 4.19
US Distillate Exports



Source: IHS Energy, EIA © 2014 IHS

Exports of both gasoline and distillates (diesel and other similar gas oils) have more than quadrupled since the last decade, with distillate shipments now averaging over 1 million B/D annually. Gasoline exports have risen particularly fast, growing from roughly 200,000 B/D in 2009 to more than 550,000 B/D last year. The majority of gasoline exports have been to Mexico and

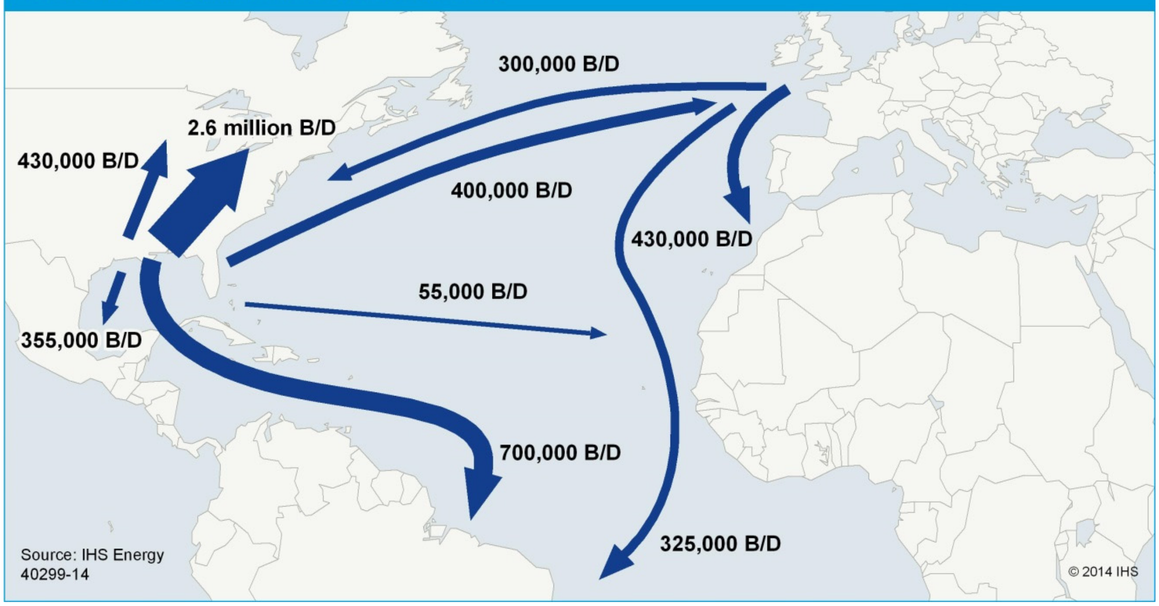
Latin America, markets with fast-growing demand and insufficient refining capacity. For similar reasons, export volumes to West Africa have also picked up. So product is not only being pushed by Gulf Coast refineries leveraging an advantage in their low production costs, but is also being pulled" by international markets short on refining capacity of their own. The primary export destinations for the United States—Mexico and Brazil—have ambitious refinery construction projects that have been plagued by delays and cost overruns; these projects add uncertainty to US product exports.

There is an active international trade in gasoline with imports from Europe into the East Coast and exports of gasoline and diesel from the Gulf Coast to Europe and Latin America. This trade, while seeming somewhat odd, provides the most economically optimum supply from the refining centers to the markets served.

Europe, which produces surplus gasoline, collectively exports several hundred thousand barrels per day to Africa, Latin America, and the US East Coast. These trading relationships effectively make the Atlantic Basin a single, interconnected product market. Prices for various products invariably move together because of this connectivity.

As noted previously, a single refinery can simultaneously process multiple crudes from US plays, offshore countries, or Canada. The gasoline produced is from a diverse mix of streams within the refinery, and there is no method or need to identify which products are derived from what crude oils processed. Even with strong exports, over 90% of the US refinery gasoline production today is sold in the US market.

FIGURE 4.20
Gasoline and Distillate Trade Flows: 2013



Source: IHS Energy
40299-14

ATLANTIC GASOLINE TRADE AND PRICE LINKAGE

With significant trading of gasoline in and between European and the Gulf Coast markets, prices in these key Atlantic Basin markets should be linked. An analysis of this price-setting mechanism does show a strong relationship in most years. The analysis uses historical prices and water-borne transportation costs to illustrate how trade flows explain the price relationship that exists among the Gulf Coast, Europe and one of their common export markets, Mexico. By confirming this trans-Atlantic price relationship, we can demonstrate that US gasoline prices closely track international product prices.

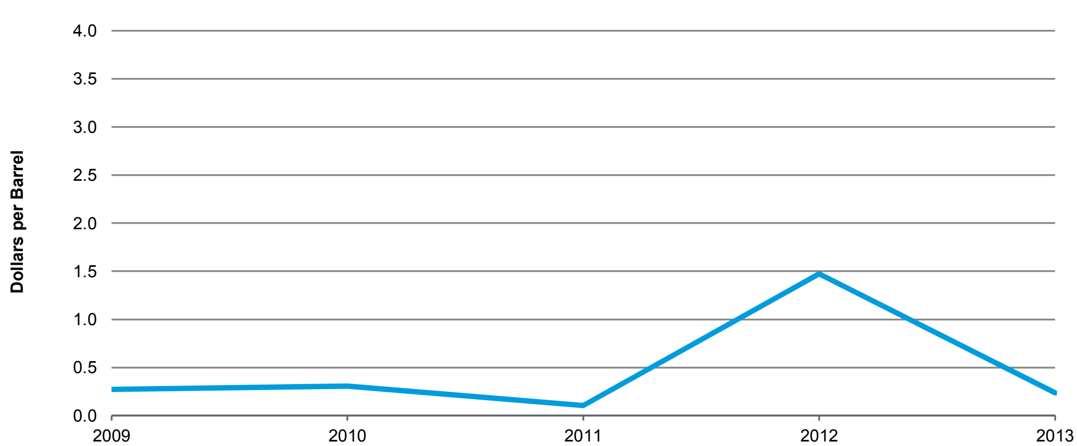
With over 40% of European gasoline exports going to the US East Coast (USEC), this trade flow is assumed to establish the price linkage between Europe (Rotterdam) and the USEC (New York Harbor). Since Mexico is importing gasoline from both the US Gulf Coast and Europe, trade flows into Mexico are expected to strongly influence the USEC and Gulf Coast gasoline price relationship. Three trade flows best demonstrate the price relationship between the US market and Europe.

- Rotterdam to USEC
- Rotterdam to Mexico
- Gulf Coast to Mexico

Transportation costs are used to estimate the delivered and netback prices among these markets. The gasoline price in Mexico was netted back to the Gulf Coast by subtracting transportation costs and was then compared to historical gasoline prices in the Gulf Coast. As shown in Figure 4.21, Gulf Coast prices between 2009 and 2011 very closely tracked the Gulf Coast netback price from Mexico–to within 25 cents per barrel. This shows that Gulf Coast prices were very strongly influenced by international prices and were set by the export parity price with Mexico.

The following year, 2012, the netback price from Mexico widened to $1.50 per barrel over the historical Gulf Coast price, but it quickly reverted to trade parity in 2013. This brief price divergence was due to an increase in East Coast prices due to the refinery shutdowns there that required additional US East Coast gasoline imports from non-Atlantic Basin locations (e.g., India); this impacted the price in Mexico due to the product trade linkages between Europe, the US East Coast and Mexico.

FIGURE 4.21
USGC Gasoline Price versus Calculated Gasoline Netback Price From Mexico



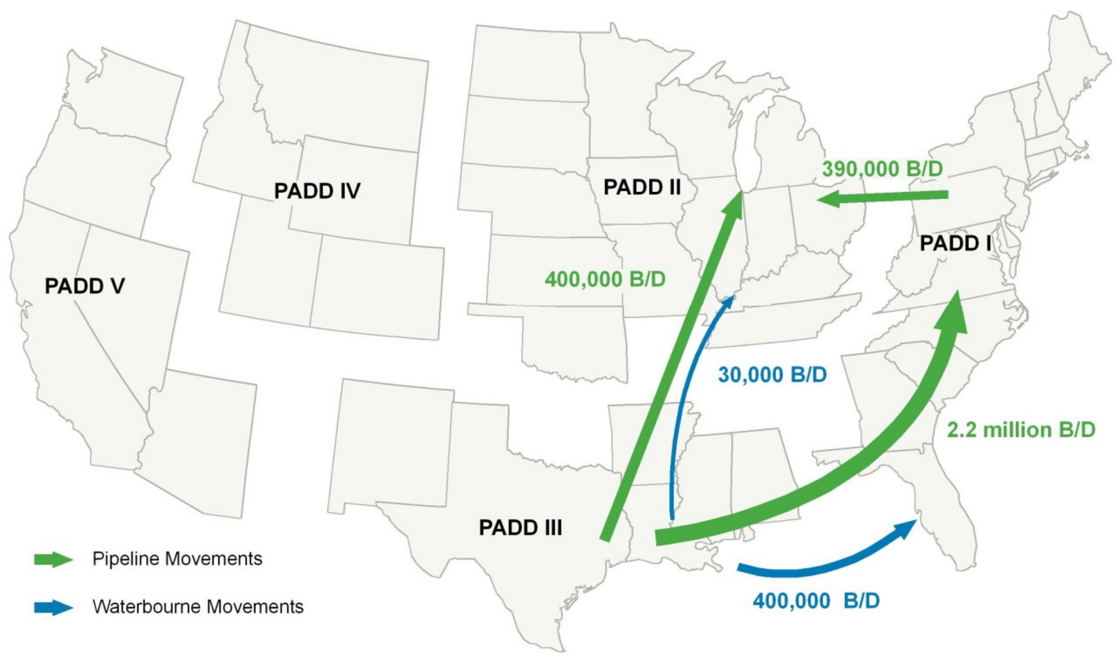
Note: Netback price refers to the calculated price in the USGC after subtracting the transportation costs from the price in Mexico
Source: IHS Energy, Platts

US Regional Gasoline Pricing

US gasoline prices vary from region to region. In this analysis, IHS has used region level (PADD) average retail pricing available from the US EIA to evaluate whether regional US gasoline prices are linked to the movement of products and to examine whether the WTI domestic crude price has any notable influence on regional gasoline prices.

In the same way that trade flows link prices in the broader Atlantic Basin, prices *within* the United States are linked by product movements. The Gulf Coast, for example, supplies well over 3 million B/D of gasoline and distillate to the rest of the country, mostly by pipeline but also by barge or tanker. As shown in Figure 4.22 below, the bulk of this flow is sent to the East Coast, but a sizeable volume is shipped to the Midwest. Additionally, markets in the northeastern corner of the Midwest receive nearly 400,000 B/D of gasoline and distillate by pipeline from the East Coast.

FIGURE 4.22
Inter-PADD Gasoline and Distillate Trade Flows: 2013



Source: IHS Energy
40299-17

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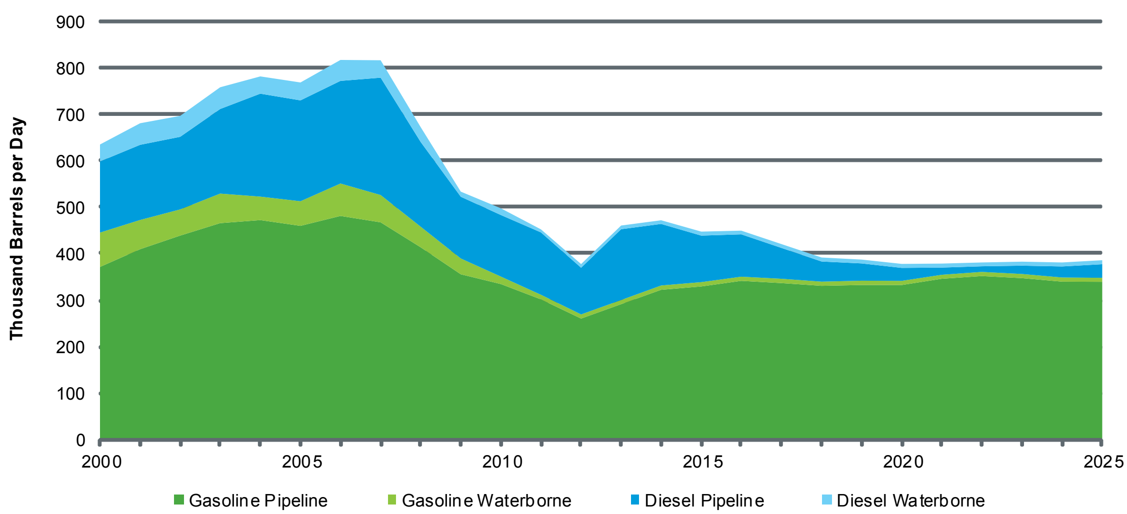
While Gulf Coast shipments to the Midwest have fallen significantly over the past few years due to eroding demand and increased regional production, the Midwest remains dependent on external supply. The Midwest is expected to continue to be supplemented from the Gulf Coast for the foreseeable future, especially for gasoline, despite the recent decline in shipments from the Gulf. For this reason, prices in Chicago are linked to prices in Houston, which are linked to prices on the East Coast and in Europe, Mexico and the rest of the Atlantic Basin.

FIGURE 4.23
Transfers from PADD III to PADD II

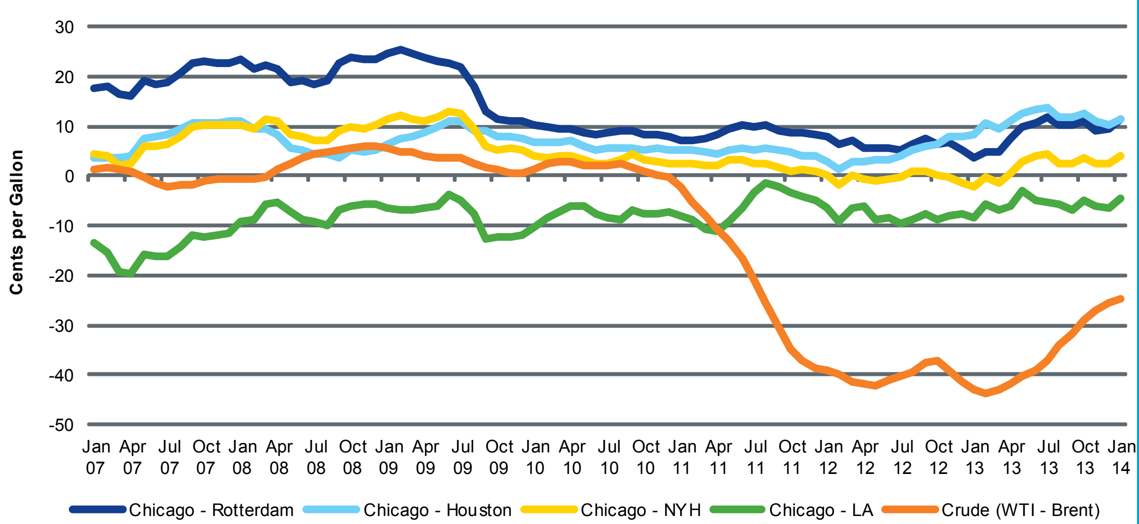


Source: EIA, IHS Energy © 2014 IHS

GASOLINE PRICE RELATIONSHIPS

While it may seem intuitive that the price of crude oil refined in a market would set the price for the refined products in that market, that is not the case. Instead, as we have seen, product prices in any given market (when trade is free and open) are linked to the broader *global* product market. The events of the past few years reinforce this conclusion.

FIGURE 4.24
Inland US Gasoline Price Differentials (12 Month Moving Average)



Source: Platts, IHS Energy Note: NYH = New York Harbor, LA = Los Angeles, WTI = West Texas Intermediate © 2014 IHS

Beginning in early 2011, surging US crude production exceeded processing capacity in Midwestern markets, giving rise to a crude discount that provided an important feedstock advantage to Midwestern refineries—a discount that made the crude processed by these refineries significantly cheaper than that processed by refineries in the Gulf Coast and everywhere else in the world. And yet, as shown in Figure 4.24, the price for gasoline in the Midwest retained more or less the same relationship with other major US and international markets. Despite Midwestern refineries' access to cheaper crude, a gasoline supply deficiency and reliance on Gulf Coast gasoline makes the Chicago gasoline price slightly *higher* on average than the gasoline price in Houston in order to incentivize gasoline movements from the Gulf Coast to Chicago.

Figure 4.24 shows, the links between Chicago gasoline prices and prices in other markets are stable, because they are all linked to the same *global* market. Take Chicago and Los Angeles, for example, despite being separated by thousands of miles and having no direct interaction in terms of crude or product trade, the difference between the gasoline prices in these two indirectly connected markets has been remarkably steady in recent years.

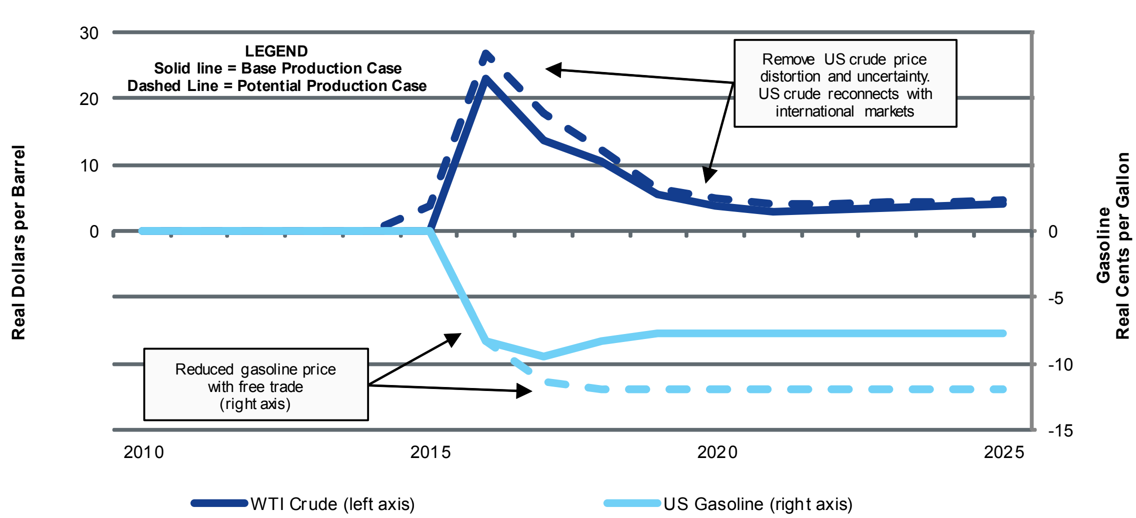
SUMMARY OF US GASOLINE AND CRUDE PRICES MOVEMENTS

The price relationship between US crude oil and US gasoline cannot be considered in isolation from world markets.

Gasoline's tie to international crude through the free trade of refined products is based on changes in the global Brent price. But under the restrictive trade policy for domestically produced crude oil, the distorted pricing of US crude, evident in the LTO discount, has a fundamentally different pricing dynamic.

The shift of the US crude market to free trade will have the effect of lowering US gasoline prices. That is because as new crude supply is added to the global market, the international price of crude will fall, putting downward pressure on US gasoline prices. At the same time, free export of US crude oil would actually increase domestic crude prices, which will rise to meet higher international price levels, generating additional US output and adding to international crude supply.

FIGURE 4.25
Free Trade Impact on US Crude and Gasoline



Source: IHS Energy

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The net gasoline and crude price changes for both Free Trade Cases is provided in Figure 4.25. This shows the dual benefit of free trade: producers receive greater price certainty and somewhat higher crude prices and consumers receive lower gasoline prices as a result of the direct effects of greater global crude supply. Specifically, free trade would:

- Reduce gasoline prices paid by US consumers by an estimated 8 cents per gallon (Base Production) and 12 cents per gallon (Potential Production) over the entire forecast period. As US crude production increases by another 1-2 million B/D under free trade, lower prices in the global market result in lower US gasoline prices.

- Remove the price uncertainty associated with the discount on US light crude oil, generating the economic benefits of higher crude production, increased investment, higher employment, higher household income, an improved US petroleum trade balance and increased tax revenues. How that works is the subject of the next chapter.

V. MACROECONOMIC RESULTS

KEY INSIGHTS

- The impact on the US economy of a free trade policy on crude exports is significant. Upstream direct capital investment and production are the key drivers for the economic and household benefits associated with the free trade of crude oil. Free trade increases production and investment by 1.2 million B/D and $66 billion (peak) in the Base Production Case and 2.3 million B/D and $82 billion (peak) in the Potential Production Case.
- The cumulative difference in upstream direct capital investment totals $751 billion in the Base Production Case and $995 billion in Potential Production case over the forecast period of 2016 to 2030.
- Gross domestic product (GDP) in the Base Production Case with free trade will peak in 2018 at $135 billion higher, or 0.7%, more than with the current restricted trade policy. The peak impact is greater in the Potential Production Case when GDP under free trade will be $221 billion, or 1.2%, higher.
- Increased economic activity will fuel job creation and lower the unemployment rate. Jobs will peak at 964,000 in 2018 in the Base Production Case, and at 1.5 million in 2018 the Potential Production Case. The annual total US employment increase due to free trade will be 394,000 and 859,000 on average from 2016 through 2030 for the Base Production and Potential Production Cases, respectively.
- A stronger labor market with free trade relative to restricted trade will increase the average annual household's disposable income by $239 and $465 during 2016-2030 in the Base and Potential Production Cases, respectively. The peak annual household disposable income are considerably higher with the Base Production Case peaking in 2018 at $391 and the Peak Production Case peaking in 2021 at $733.
- The impact of free trade and associated higher crude oil production on US petroleum trade is considerable.[63] The 2013 US bill for imported petroleum is calculated at $218 billion. In the Base Production Case this is reduced to an average of $68 billion from 2016 through 2030, $67 billion lower than the import bill with restricted trade. In the Potential Production Case the increase in production with free trade is substantial enough to turn the balance of US petroleum payments positive. In this case, free trade averages a surplus of $55 billion from 2016 through 2030, a $93 billion improvement over restricted trade on an annual average basis.
- Total government revenues from corporate, personal and energy-related taxes and royalties are expected to increase under free trade. The cumulative addition to revenue is $1.3 trillion from 2016 through 2030 in the Base Production Case and more than double that—$2.8 trillion—in the Potential Production Case.
- Benefits from free trade of crude oil are distributed throughout the US. Jobs growth and economic benefits flow across all states and not just in large oil producing states due to substantial supply chains supporting the field production, transportation and refining of crude oil. For example, 24% of the additional jobs resulting from the Base Case free trade are located outside of the crude oil producing states.

A summary in Table 5.1 of the macroeconomic analysis shows the benefits to the US economy of a free trade policy for crude oil, relative to the current restricted policy. The analysis separately compares the economic benefits of free trade, for the Base Production Case and for the Potential Production Case:

[63] Petroleum trade defined as the net imports (imports minus exports) of crude oil, refined products and NGLs.

TABLE 5.1
Impact of Free Trade (vs. Current Restricted Trade Policy)

	Base Production Case	Potential Production Case
Crude Oil Production, average, 2016-2030 (million B/D)	1.2	2.3
US Gasoline Price, average, 2016-2030 (cents per gallon, real)	-8	-12
Fuel Cost Savings, cumulative, 2016-2030 ($ billion)	265	418
Investment		
Peak Annual Investment ($ billion)	66 in 2017	82 in 2017
Cumulative Oil Production-related, 2016-2030, ($ billion)	751	995
Cumulative Refining-related, 2016-2030, ($ billion)	-5	-21
Cumulative Investment, 2016-2030, ($ billion)	746	974
Gross Domestic Product		
Peak Growth (percent)	0.7 in 2018	1.2 in 2018
Peak ($ billion, real)	135	221
Average, 2016-2030 ($ billion, real)	86	170
Net Petroleum Trade, average, 2016-2030 ($ billion, real)	67	93
Employment		
Average, 2016-2030 (thousand)	394	859
Peak (thousand)	964 in 2018	1,537 in 2018
Disposable Income per Household		
Average, 2016-2030 ($, real)	238	466
Peak ($, real)	391 in 2018	733 in 2021
Cumulative Government Revenue (2016-2030) ($ billion)	1,311	2,804

Source: IHS Energy Insight and IHS Economics

INTRODUCTION

It has been more than 40 years since the United States imposed restrictions on exporting most domestically produced crude oil. If this ban is lifted, exports of domestically-produced crude oil will have an immediate and significant impact on the US economy. In this section, we describe the methodology used to assess the impact of changing crude export policy. We identify the main underlying assumptions in our assessment, and the implications for the broader economy in terms of gross domestic product (GDP), employment, total trade, and government revenue. We also discuss the impact on state economies in terms of employment and gross state products.

We compare the economic impact of a change to the free trade of crude oil with a case that assumes that the status quo of restricted exports is maintained. The objective is to provide a framework for understanding the various economic consequences of these two cases in each Production Case (Base and Potential). Our macroeconomic findings are quantified in terms of GDP, employment, household income, government revenue and total trade.

METHODOLOGY

Critical inputs that underlie all of the restricted and free trade cases are the projections of US crude oil production discussed in Section II of this report. Provided below is a summary of the trade cases with each production forecast:

FIGURE 5.1
Basis for Production Cases and Trade Policies

Production Cases

Trade Policies	**Base** IHS central planning forecast. Conservative view based on defined plays and assumes limited industry improvements.	**Potential** Includes additional potential but less well defined areas of existing plays, moderate industry drilling and technology improvements.
Restricted Current policies (including condensate treatment as crude).	Base Production / Restricted Trade	Potential Production / Restricted Trade
Free Trade to broad group of trading partners including Europe and Asia (India, China).	Base Production / Free Trade	Potential Production / Free Trade

Trade Policy Decision

Difference in Underlying US Production Forecast View

Note: Each case starts with the same IHS macroeconomic and international crude oil price forecast

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In the Base Production Case, the restricted trade policy environment is calibrated using IHS' baseline macroeconomic forecast (which represents current US policy). The alternative free trade policy in this case assesses the incremental contributions to the US economy of removing existing crude oil export trade restrictions.

In the Potential Production Case, IHS revised the related energy assumptions—oil production, prices, investment and petroleum trade—in the latest IHS long term macroeconomic forecast. In the restricted trade case, this resulted in larger benefits for the US economy, though they were still lower than the comparable free trade alternative. IHS then removed the crude oil export restrictions to provide this corresponding free trade assessment and evaluate its incremental contributions to the US economy.

A summary of the four production-trade combination cases is provided below.

- **Base Production Case:**
  - Free Trade: This case removes restrictions on exports of domestically produced crude oil. In this case, domestic production reaches a peak of 11.2 million B/D in 2022.
  - Restricted Trade: Domestic crude oil production reaches 10 million B/D in 2022, and the United States maintains the current policy, which is an effective ban on exports of domestically-produced crude oil during the outlook period 2016-2030.
- **Potential Production Case:**
  - Free Trade: The restrictions on exports of domestically produced crude oil are removed, which encourages even more production. Domestic oil production reaches a peak of 14.3 million B/D in 2025.
  - Restricted Trade: Domestic production of crude oil increases and the ban on exports of crude oil stays in effect through the outlook period. In this case, domestic oil production reaches a peak of 11.8 million B/D in 2025.

In comparing the four cases developed by IHS, it is important to note that these are not four independent cases. A case must be compared against one of the other cases to evaluate the impact that a change in the crude oil trade policy or production outlook could have on the US economy. In Figure 5.1 above, cases that are horizontally or vertically adjacent to each other can be compared, but comparisons cannot be made between cases that are diagonal to each other. For example, comparing the Base Production / Free Trade Case to the Potential Production / Restricted Trade Case will not produce meaningful results as there is no plausible future environment where decisions or trade-offs could be made between those two cases.

The free trade policy identifies six first-order factors that would be directly affected by changing crude oil export policy. These factors are:

1. Impact on domestic crude oil, NGLs and associated natural gas production.
2. Impact on the refiner acquisition cost of crude oil.[64]
3. Impact on investment in the upstream, midstream and downstream oil sectors.
4. Impact on the level of crude oil exports.
5. Impact on the level of crude oil imports.
6. Impact on the price of gasoline and other refined products.

The historical data for the IHS macroeconomic model is sourced from the Bureau of Economic Analysis, National Income and Product Accounts, which was recently rebased to chain weighted 2009 dollars. The macroeconomic results are consistent with the published government data and are expressed in real 2009 dollars throughout the report.

This analysis is based on a systematic review of all major unconventional and conventional oil plays that are expected to develop in the United States during the forecast period. We assess how increased oil production from these resources would ripple through the upstream oil sector.

PETROLEUM INDUSTRY INPUTS

Oil Production and Investment: In the Base Production Case, lifting the restrictions on exports of crude oil would enable the United States to increase to a peak oil production of 11.2 million B/D by 2022. Overall the free trade policy results in an average 1.2 million B/D more in crude oil production than in the restrictive policy between 2016-2030.

TABLE 5.2
Crude Oil Production: Case Comparison
(million barrels per day)

	Peak Production (Year)	Increase in Production from 2015 to Peak Year	Average Production 2016-2030
Base Production Case			
Free Trade	11.2 (2022)	2.0	10.7
Restricted Trade	10.0 (2022)	0.8	9.5
Difference Free Trade vs. Restricted Trade	**1.2 (2022)**	**1.2**	**1.2**
Potential Production Case			
Free Trade	14.3 (2025)	4.8	13.3
Restricted Trade	11.8 (2025)	2.5	11.0
Difference Free Trade vs. Restricted Trade	**2.5 (2025)**	**2.3**	**2.3**

Source: IHS Energy

[64] The average cost paid for crude oil by US refiners (refinery gate location) includes both domestic production and imports.

The Potential Production Case assumes a stronger oil production outlook, peaking at 14.3 million with free trade. The difference in crude oil production between the two trade policies averages annually 2.3 million B/D between 2016 and 2030.

To support oil production increases in the upstream sector that would be associated with free trade, capital spending will rise. Higher spending will be for drilling, completion, facilities and gathering systems. This will directly impact industries such as machinery, fabricated metals, steel, chemicals and engineering services. In the Base Production Case, free trade results in an increase in capital spending that peaks in 2017 at approximately $66 billion per year—32% higher than with the restricted trade policy. These gains from free trade moderate in the second half of the forecast, but capital spending continues to be 20% higher in the free trade environment relative to the current policy of restricted trade.

In the Potential Production Case, the difference in capital spending between free and restricted trade is calculated to peak in 2017 at $82 billion—40% higher under free trade. Similar to the Base Product Case the gap moderates in the second half of the forecast but continues to be substantially higher under free trade.

The cumulative upstream investment differences over the forecast period (2016-2030) between free trade and restricted trade are $751 billion in the Base Case and $995 billion for Potential Case.

TABLE 5.3
Upstream Direct Capital Investment: Case Comparison
($ billion, nominal)

	Peak Upstream Capex (Year)	Average Annual Capex 2016-2030	Cumulative Investment 2016-2030
Base Production Case			
Free Trade	273 (2017)	300	4,501
Restricted Trade	207 (2017)	250	3,750
Difference Free Trade vs. Restricted Trade	**66 (2017)**	**50**	**751**
Potential Production Case			
Free Trade	285 (2017)	340	5,102
Restricted Trade	203 (2017)	274	4,109
Difference Free Trade vs. Restricted Trade	**82 (2017)**	**66**	**995**

Source: IHS Energy

Refiner Acquisition Cost: The restrictive crude export policy has widened the gap between the price that US refiners pay for domestically produced crude oil and the higher prices at which they sell their refined products. In the Base Production Case, lifting the restrictions on crude oil exports and trade will close this gap by increasing refiners' feedstock acquisition costs by almost $14 per barrel in 2016, (the maximum year) before this effect moderates in 2018 due to the impact of adding simple refinery topping capacity in the restricted trade environment. In the Potential Production Case, refiners' feedstock acquisition costs increase $18 in 2016 (maximum year) in the free trade case compared with the restricted case. Again, there will be the same moderating influence associated with the addition of a much higher level of simple refinery topping capacity. With free trade in both production cases, the refiners' acquisition costs are further reduced (narrowed compared to restricted trade) due to a reduction in international crude prices associated with additional US production and global supply.

TABLE 5.4
Refiners' Acquisition Cost: Case Comparison
($ per barrel, real)

	Maximum Difference (2016)	Average Cost 2016 - 2020	Average Cost 2021 - 2030	Average Cost 2016 - 2030
Base Production Case				
Free Trade	92.2	96.3	116.4	109.5
Restricted Trade	77.8	89.2	113.8	105.6
Difference Free Trade vs. Restricted Trade	**14.4**	**7.1**	**2.6**	**3.9**
Potential Production Case				
Free Trade	91.4	92.7	110.3	104.4
Restricted Trade	73.6	84.5	107.7	100.0
Difference Free Trade vs. Restricted Trade	**17.8**	**8.2**	**2.6**	**4.4**

Source: IHS Energy

US Retail Gasoline Price: Lower global refined product prices associated with free trade will have an impact on the US market for refined products. In the Base Production Case, the average US gasoline retail price decreases by 8 cents per gallon (Table 5.5) when a free trade policy replaces the current trade policy. In the Potential Production Case, the refined products PPI declines by 5% between 2016-2018 under free trade, compared to the current crude oil trade policy. The Potential Production Case has a greater impact on domestic gasoline prices, which will be lower by 12 cents over the same period. The change in gasoline price and PPI for refined products are the primary petroleum product inputs into the macroeconomic model.[65]

TABLE 5.5
US Retail Gasoline Price: Case Comparison
($ per gallon, real)

	Average Cost 2016 - 2018	Average Cost 2019 - 2021	Average Cost 2022 - 2030	Average Cost 2016 - 2030
Base Production Case				
Free Trade	3.18	3.34	3.70	3.52
Restricted Trade	3.27	3.42	3.78	3.60
Difference Free Trade vs. Restricted Trade	**-0.09**	**-0.08**	**-0.08**	**-0.08**
Potential Production Case				
Free Trade	3.13	3.22	3.57	3.41
Restricted Trade	3.23	3.34	3.69	3.53
Difference Free Trade vs. Restricted Trade	**-0.10**	**-0.12**	**-0.12**	**-0.12**

Source: IHS Energy

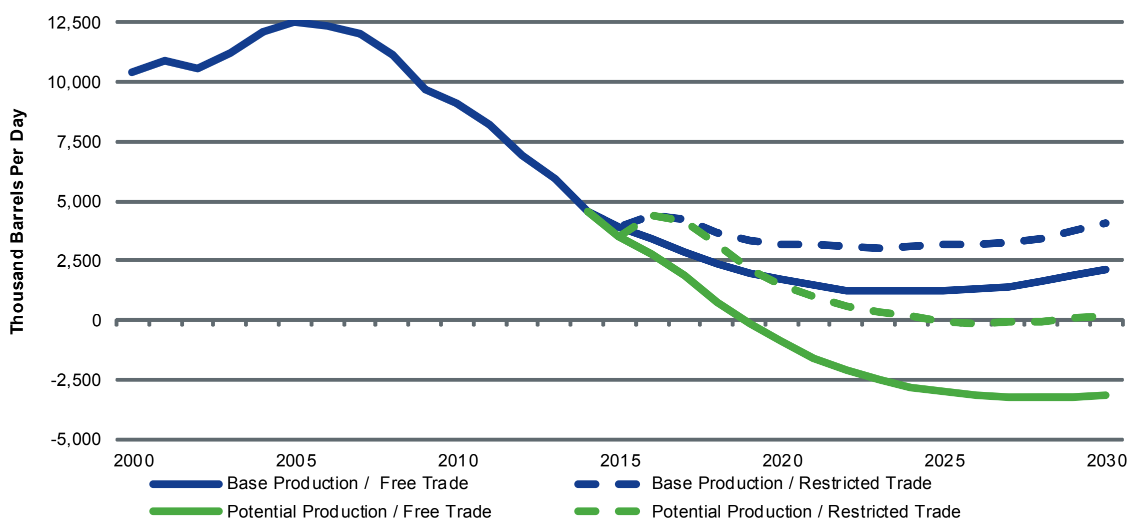
Petroleum Trade: In 1975, when the Energy Policy and Conservation Act was enacted, there was a deficit (imports of US petroleum exceeded exports) of 5.9 million B/D. By 2005, this had more than doubled to just over 12.5 million B/D. Since 2005, the US petroleum trade deficit has been cut in half to 6 million B/D, due to a combination of three factors. The three factors resulting in this 6.5 million B/D reduction, in declining order of importance, are listed below, including their individual impacts on reducing the deficit:[66]

[65] The Producer Price Index (PPI) reflects the price trends of a set of goods producers receive (weighted by their relative importance) that together represent the price of a commodity.
[66] Petroleum trade is defined as the sum of net trade (imports minus exports) in crude oil, refined products, and NGLs.

- Crude Oil and NGL Production Growth: 3.5 million B/D
- Demand Reduction from Efficiency Gains and Recession: 2.3 million B/D
- Fuel Substitution Measures: 0.7 million B/D[67]

In each of the production and trade cases, the trend towards declining petroleum imports and growing petroleum self-sufficiency continues but to varying degrees—particularly post-2015, when the restrictive and free trade cases diverge. Under a restricted trade policy, progress towards self-sufficiency is halted in 2016 and reverses as Gridlock takes hold of the US petroleum industry and then slowly unwinds itself over the next three years. Figure 5.2, shown below, provides the net impact (imports minus exports) in volumetric terms to US petroleum trade for each production trade case.

FIGURE 5.2
US Net Trade of Crude Oil, Refined Products, and NGLs in Base and Potential Production Cases



Source: IHS Energy, EIA © 2014 IHS

The light tight oil (LTO) production revival has already resulted in substantial improvements to the country's significant and long standing financial petroleum trade deficit, i.e. the US petroleum import bill. IHS calculates that the US petroleum import bill stood at $311 billion in 2011, by 2013 this had been reduced by 30% or $93 billion, to $218 billion.[68] This reduction in the US petroleum trade deficit in projected to continue until the onset of Gridlock in 2016.

In the Base Production Case this is reduced to an average of $68 billion from 2016 through 2030, $67 billion lower than the import bill with restricted trade. In the Potential Production Case the increase in production with free trade is substantial enough to turn the balance of US petroleum payments positive. In this case, free trade averages a surplus of $55 billion from 2016 through 2030, a $93 billion improvement over restricted trade on an annual average basis.

[67] Mainly the substitution of corn based ethanol for petroleum gasoline.
[68] IHS calculation for the US net petroleum trade deficit is slightly different from the EIA Merchandise Trade Value statistics. The primary difference being EIA data is based on import/export customs data where IHS uses EIA imports and export volumes multiplied by applicable spot benchmark price quotations to provide consistency for forecasting purposes.

TABLE 5.6
US Net Petroleum Trade: Case Comparison
($ billion, real)

	2015	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Base Production Case								
Free Trade	130.1	117.1	98.0	79.3	67.0	59.4	59.2	67.5
Restricted Trade	130.1	160.2	145.6	125.2	116.1	116.3	135.2	134.3
Difference Free Trade vs. Restricted Trade	**0.0**	**-43.1**	**-47.6**	**-45.9**	**-49.1**	**-57.0**	**-76.0**	**-66.8**
Potential Production Case								
Free Trade	121.3	96.5	68.5	29.1	2.7	-24.2	-100.9	-55.7
Restricted Trade	121.3	150.0	141.4	103.5	70.2	49.9	4.4	37.3
Difference Free Trade vs. Restricted Trade	**0.0**	**-53.5**	**-73.0**	**-74.4**	**-67.6**	**-74.1**	**-105.3**	**-93.0**

1. Average of the years 2021-2030.
2. Average of the years 2016-2030.
Source: IHS Economics

BROAD IMPACT ON THE US ECONOMY

GROSS DOMESTIC PRODUCT

Lifting the restrictions on crude oil exports will have major, measurable benefits for US gross domestic product. As discussed above in the Base Production Case, GDP improvement with free trade of crude oil will average $86 billion of additional annual economic output to the US economy with a peak benefit of $135 billion in 2018 (Table 5.7). The main economic driver of this robust growth is the increase in fixed investments by businesses in the upstream oil producing and gathering sector.[69]

TABLE 5.7
Gross Domestic Product: Base and Potential Production Cases
($ billion, real)

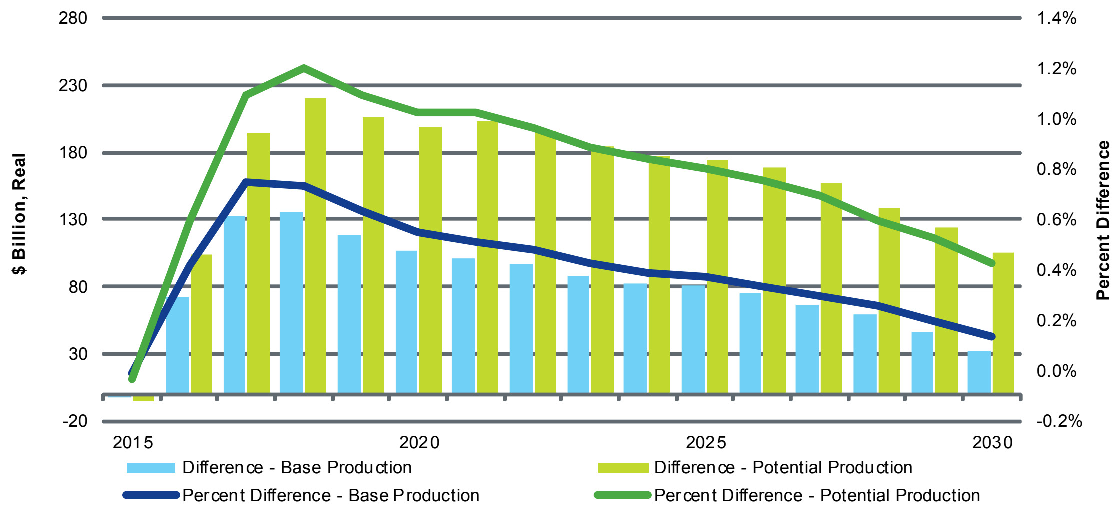
	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Base Production Case							
Restricted Trade	17,293	17,833	18,330	18,815	19,289	21,921	20,718
Free Trade	17,366	17,966	18,465	18,933	19,395	21,994	20,805
Difference Free Trade vs. Restricted Trade	**72.8**	**132.9**	**134.9**	**118.7**	**106.3**	**73.0**	**86.4**
% Difference Free Trade vs. Restricted Trade	**0.4%**	**0.7%**	**0.7%**	**0.6%**	**0.6%**	**0.3%**	**0.4%**
Potential Production Case							
Restricted Trade	17,326	17,862	18,376	18,880	19,357	21,985	20,777
Free Trade	17,429	18,056	18,597	19,087	19,555	22,148	20,947
Difference Free Trade vs. Restricted Trade	**103.4**	**194.7**	**220.9**	**206.1**	**198.3**	**162.8**	**170.1**
% Difference Free Trade vs. Restricted Trade	**0.6%**	**1.1%**	**1.2%**	**1.1%**	**1.0%**	**0.7%**	**0.8%**

1. Average of the years 2021-2030.
2. Average of the years 2016-2030.
Source: IHS Economics

In the Potential Production Case, the impact on the economy is far greater. The difference in GDP between free trade and the current trade policy is projected to average more than $170 billion across the forecast period and with a peak difference in 2018 of $221 billion or a 1.2% improvement in GDP with free trade of crude oil.

[69] Impacts on the midstream and downstream industries in each of the production—trade cases has also been assessed; however, the investment difference between the free and restricted trade policies is much smaller than the upstream industry impact and as such is not included in the main discussion.

FIGURE 5.3
Gross Domestic Product - Free Trade versus Restricted Trade



Source: IHS Economics © 2014 IHS

EMPLOYMENT

Higher levels of GDP, primarily driven by higher production and capital spending in the upstream segments of the crude oil value chain, will translate directly and indirectly to the nation's labor market and increase employment levels. In Table 5.8, the labor market impacts follow the same pattern as real GDP: strong gains in the early years and more moderate gains in the longer term.

TABLE 5.8
Employment: Base and Potential Production Cases (thousands)

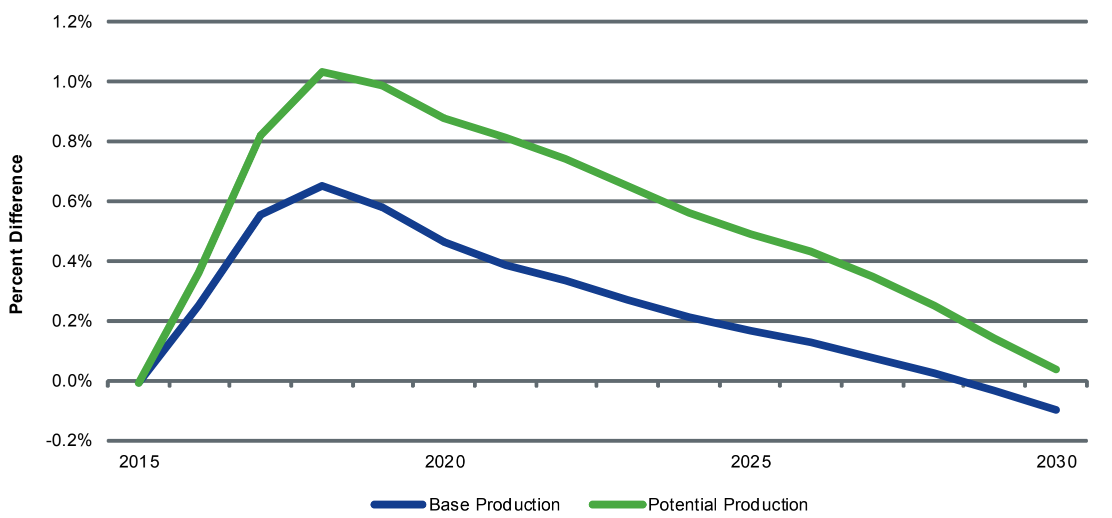
	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Base Production Case							
Restricted Trade	144,194	146,679	148,350	149,458	150,422	154,235	152,097
Free Trade	144,553	147,490	149,314	150,321	151,122	154,456	152,491
Difference Free Trade vs. Restricted Trade	**359**	**811**	**964**	**863**	**700**	**222**	**394**
% Difference Free Trade vs. Restricted Trade	**0.2%**	**0.6%**	**0.6%**	**0.6%**	**0.5%**	**0.1%**	**0.3%**
Potential Production Case							
Restricted Trade	144,402	146,872	148,603	149,827	150,844	154,469	152,349
Free Trade	144,923	148,078	150,140	151,310	152,164	155,151	153,208
Difference Free Trade vs. Restricted Trade	**521**	**1,206**	**1,537**	**1,483**	**1,320**	**682**	**859**
% Difference Free Trade vs. Restricted Trade	**0.4%**	**0.8%**	**1.0%**	**1.0%**	**0.9%**	**0.4%**	**0.6%**

1. Average of the years 2021-2030.
2. Average of the years 2016-2030.
Source: IHS Economics

In the Base Production Case, increased exports from the free trade of crude oil will support an additional 964,000 jobs at the peak employment level occurring in 2018, relative to the current restricted trade policy. Between 2016 and 2030, increased crude oil exports will support an increase of 394,000 jobs annually, on average.

The labor market impact in the Potential Production Case is even stronger. Comparing the two trade policies, the employment gains from free trade amount to 1.5 million additional jobs—or 1.0% more employment relative to current polices—by 2018. Between 2016 and 2030, the job gains will average 859,000 jobs per year, on average.

FIGURE 5.4
Employment - Free Trade versus Restricted Trade



Source: IHS Economics © 2014 IHS

TOTAL TRADE

IHS' current outlook shows that the US total net trade balance will turn positive for the first time in almost five decades occurring in 2023. A decline in the value of the US dollar relative to other industrialized countries' currencies, combined with modest unit labor cost growth, will stimulate total US exports. A smaller bill for imported petroleum and refined products will slow US imports, resulting in an eventual improvement in the US net trade balance.

Exports are expected to be driven by capital goods, excluding automotive. Among the industries that will exhibit higher than average growth are computers and other information technology equipment, aircraft, and capital goods such as semiconductors. Compound annual growth rates for these categories will be 12.8% for computers, 6.2% for aircraft, and 8.6% for capital goods. Real imports, meanwhile, will grow at an average annual rate of 3.9%—more slowly than exports. This slowdown in imports is expected to be led by petroleum and products (-0.9%) followed by food (1.0%), automotive (1.3%) and consumer goods (3.6%).

In the Base Production Case, free trade results in higher levels of GDP, personal income and consumption and lower unemployment levels, which will lead to an increase in total imports for the first six years of the forecast period. The difference in free trade versus restricted trade peaks at 1.9% in 2016. After this initial period, the growth rate in imports slows to a pace that is lower than the growth rate in exports and the difference between the two trade environments narrows, allowing the US trade balance to improve.

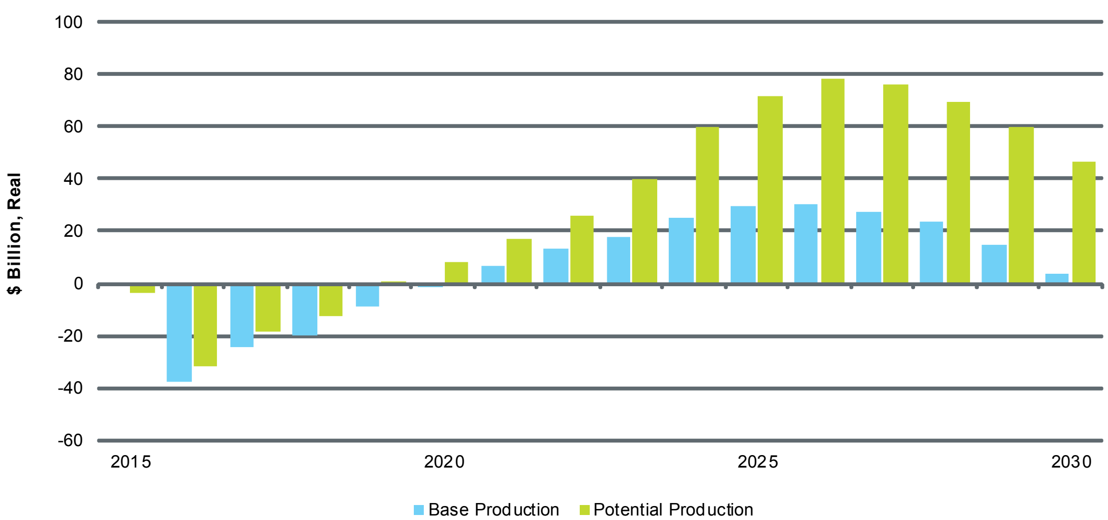
Stronger consumption and GDP growth with free trade in the Potential Production Case will spur a larger increase in total imports, and the percent difference between the two trade environments will stay relatively constant at just below 2.0% throughout the forecast period. This is offset to a degree due to the increase in crude oil exports. The difference in the case specific trade balance will turn positive in 2019—the free trade scenario will result in a positive trade balance—and will continue to improve at a stronger rate when compared to the corresponding Base Production Case.

TABLE 5.9
Total Net Trade: Base and Potential Production Cases
($ billion, real)

	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Base Production Case							
Restricted Trade	-470	-446	-398	-311	-217	156	-19
Free Trade	-508	-470	-417	-320	-218	176	-12
Difference Free Trade vs. Restricted Trade	**-37.9**	**-24.4**	**-19.7**	**-8.5**	**-1.3**	**19.2**	**6.7**
% Difference Free Trade vs. Restricted Trade	**8.1%**	**5.5%**	**4.9%**	**2.7%**	**0.6%**	**12.3%**	**-36.0%**
Potential Production Case							
Restricted Trade	-469	-448	-400	-316	-217	174	-7
Free Trade	-500	-467	-412	-314	-209	228	33
Difference Free Trade vs. Restricted Trade	**-31.7**	**-18.5**	**-12.4**	**1.1**	**8.2**	**54.4**	**40.0**
% Difference Free Trade vs. Restricted Trade	**6.8%**	**4.1%**	**3.1%**	**-0.3%**	**-3.8%**	**31.3%**	**-551.6%**

1. Average of the years 2021-2030.
2. Average of the years 2016-2030.
Source: IHS Economics

FIGURE 5.5
Change in Net Trade - Free Trade versus Restricted Trade



Source: IHS Economics © 2014 IHS

DISPOSABLE ANNUAL INCOME PER HOUSEHOLD

Lifting restrictions on crude oil exports will increase real household disposable income in the forecast due to an investment-led expansion in economic activity and a lower unemployment rate. The increase in real disposable income per household is consistent with the expected higher levels of GDP, higher demand for labor, and lower unemployment. Between 2016 and 2030, average real income per household in the Base Production Case is projected to be $238 more annually more under free trade. This boost to annual incomes will peak in 2018 at $391 per household.

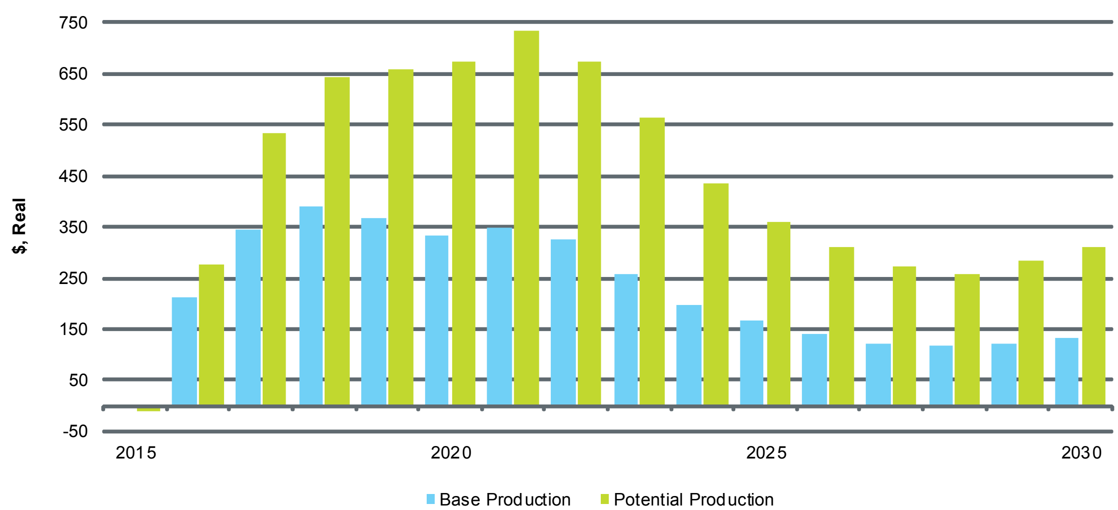
For the Potential Production Case, real disposable income per household between peaks at more than $730 more per household under a free trade policy in 2021 and averages $466 more annually over the entire forecast period.

TABLE 5.10
Real Disposable Income per Household: Base and Potential Production Cases
($, real)

	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Base Production Case							
Restricted Trade	101,789	104,434	106,524	108,262	109,704	118,212	114,189
Free Trade	102,001	104,779	106,915	108,629	110,036	118,405	114,427
Difference Free Trade vs. Restricted Trade	**212**	**345**	**391**	**366**	**332**	**193**	**238**
% Difference Free Trade vs. Restricted Trade	**0.2%**	**0.3%**	**0.4%**	**0.3%**	**0.3%**	**0.2%**	**0.2%**
Potential Production Case							
Restricted Trade	102,386	104,998	107,085	108,841	110,290	118,758	114,745
Free Trade	102,664	105,532	107,728	109,500	110,965	119,177	115,211
Difference Free Trade vs. Restricted Trade	**278**	**534**	**644**	**659**	**675**	**420**	**466**
% Difference Free Trade vs. Restricted Trade	**0.3%**	**0.5%**	**0.6%**	**0.6%**	**0.6%**	**0.4%**	**0.4%**

1. Average of the years 2021-2030.
2. Average of the years 2016-2030.
Source: IHS Economics

FIGURE 5.6
Change in Real Disposable Income per Household - Free Trade versus Restricted Trade



Source: IHS Economics

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GOVERNMENT REVENUES AND TAXES

Lifting the restrictions on domestically-produced crude oil exports will have a positive impact on the amount of revenues governments collect. Oil production on both federal and state lands will generate royalty, severance and ad valorem tax payments. Furthermore, additional capital investment and resulting increases in employment and wages will lead to increases in corporate and personal income tax payments collected by the federal, state and local governments, while a lower unemployment rate will reduce the burden of transfer payments for workers and the unemployed. Based on detailed published data on tax rates, bonus payments, and well completions in the upstream oil sector, IHS' projections of federal, state, and local government revenues are shown in the following table.

TABLE 5.11
Difference in Government Revenue: Base Production Case − Free Trade versus Restricted Trade
($ million, nominal)

	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Federal Taxes	**18,383**	**40,163**	**42,587**	**35,735**	**29,396**	**789,163**	**955,428**
Personal Taxes	11,987	32,372	38,829	33,731	25,455	650,899	793,274
Corporate Taxes	4,794	6,477	2,682	965	2,878	122,802	140,598
Federal Royalty Payments	1,551	1,262	1,036	1,010	1,034	15,155	21,047
Federal Bonus Payments	52	52	40	28	29	307	508
State and Local Taxes	**10,505**	**15,606**	**15,601**	**13,156**	**12,728**	**288,062**	**355,657**
Personal Taxes	2,234	8,341	9,907	8,077	7,260	202,241	238,059
Corporate Taxes	677	900	374	133	367	14,422	16,873
Severance Taxes	4,534	3,763	3,127	2,986	3,066	42,615	60,092
Ad Valorem Taxes	2,296	1,924	1,613	1,440	1,495	21,231	30,000
State Royalty Payments	639	549	477	446	465	6,740	9,317
State Bonus Payments	124	129	102	73	74	812	1,315
Total Government Revenue	**28,888**	**55,769**	**58,188**	**48,891**	**42,124**	**1,077,224**	**1,311,085**
Lease Payments to Private Landowners	**494**	**510**	**414**	**312**	**322**	**3,763**	**5,815**

1. Total of the years 2021-2030.
2. Total of the years 2016-2030.
Source: IHS Economics, IHS Energy

Comparing the two trade policies in the Base Production Case in Figure 5.11, total government revenues (federal, state and local) will be more than $58 billion higher in 2018 under a free trade policy for crude oil. Comparing the two trade policies in the Potential Production Case in Figure 5.12, the difference in total government revenues increase to $97 billion in 2018 and grows substantially through the remainder of the forecast in nominal dollar terms.

Over the entire forecast period, 2016-2030, lifting the restrictions of crude oil exports will generate total government revenues in excess of $1.3 trillion in the Base Production Case. The table below shows that it will generate nearly $2.8 trillion in the Potential Production Case.

TABLE 5.12
Difference in Government Revenue: Potential Production Case − Free Trade versus Restricted Trade
($ million, nominal)

	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Federal Taxes	**27,203**	**60,741**	**72,303**	**66,232**	**59,444**	**1,755,769**	**2,041,693**
Personal Taxes	16,525	47,533	62,395	60,579	51,887	1,430,874	1,669,793
Corporate Taxes	8,544	11,306	8,335	4,262	6,081	296,581	335,109
Federal Royalty Payments	2,067	1,832	1,519	1,353	1,437	27,845	36,053
Federal Bonus Payments	67	70	53	39	40	469	739
State and Local Taxes	**14,332**	**22,941**	**25,070**	**22,783**	**22,096**	**655,130**	**762,352**
Personal Taxes	3,064	11,977	15,673	15,215	14,029	487,087	547,046
Corporate Taxes	1,211	1,568	1,139	568	782	35,659	40,927
Severance Taxes	6,084	5,584	4,832	4,233	4,446	79,398	104,576
Ad Valorem Taxes	2,963	2,820	2,549	2,040	2,085	39,434	51,891
State Royalty Payments	838	807	738	621	642	12,143	15,789
State Bonus Payments	172	186	140	106	112	1,408	2,124
Total Government Revenue	**41,535**	**83,682**	**97,373**	**89,015**	**81,541**	**2,410,900**	**2,804,045**
Lease Payments to Private Landowners	**575**	**612**	**494**	**374**	**392**	**4,915**	**7,361**

1. Total of the years 2021-2030.
2. Total of the years 2016-2030.
Source: IHS Economics, IHS Energy

ECONOMIC CONTRIBUTION OF THE UNCONVENTIONAL OIL AND GAS REVOLUTION

The unconventional oil and gas revolution in the United States has already led to a steep decline in domestic energy costs relative to other developed countries. The cost of natural gas, is now roughly one-third that of Europe and one-quarter that of Asia. And given North America's large, low-cost unconventional gas resource base, low gas prices are projected to prevail as long as US continental production remains robust. The economy clearly benefits from low energy costs. US manufacturers in particular have become highly competitive in the global market, owing to the availability of secure, low-cost gas. This is especially true for energy-intensive sectors, such as chemicals, metals manufacturing, petroleum refining, glass, cement and the food industries—and their supply chains. IHS expects these industries' newfound competitive advantage to allow them to outperform the broader US economy in coming years. This advantage is prompting manufacturers to build and expand capacity. US and foreign companies have already announced plans to invest over $100 billion in US-based manufacturing.

The impact of shale gas and tight oil development on US employment has also been dramatic. The oil and gas sector—exploration, production, processing, transportation, marketing and refining—is already one of the nation's largest employers. IHS' recent study, "America's New Energy Future: The Unconventional Oil and Gas Revolution and the Economy—A Manufacturing Renaissance," calculated that the unconventional oil and gas value chain and energy-related chemicals supported 2.1 million jobs in 2012—both directly, indirectly, and through the income effect.* The study estimated this could rise to 3.3 million jobs by 2020. These jobs include those in the energy industry and in associated services and information technology firms, as well as jobs throughout the economy generated by the overall increase in spending and income in both energy and non-energy producing states.

The IHS study also analyzed this unconventional contribution to household and government income growth. IHS estimated that the unconventional energy boom increased average household disposable income in 2012 by $1,200—that is expected to grow to $2,700 by 2020. This income boost derives from lower gas and utility bills for households, plus lower prices for goods and services that result from lower-cost energy inputs throughout the economy. The IHS study also determined that the value chain associated with unconventional oil and gas contributed over $74 billion to federal and state revenues in 2012.

Total government revenues from oil and gas production are significant at both the federal and state government level. In fiscal year 2013, the US federal government received about $42 billion in taxes, royalties and bonuses for oil and gas production. At the state level total revenues comprised of taxes, royalty, severance, ad valorem and bonus payments associated with oil and gas production totaled $42 billion in 2013.

Private property laws have also allowed many US households to participate directly in the energy boom. Households that own the hydrocarbons located beneath their land can negotiate contract leases with energy companies. Typically, an energy company is granted license to drill and produce on private land in exchange for an upfront bonus payment, plus a share of the production income stream, paid to the property owner.

Finally, the unconventional oil revolution has had a significant impact on the US trade deficit. Energy trade—which is dominated by crude oil and petroleum products—has a prominent role in overall US trade in goods and services. US crude oil production has surged—displacing large volumes of imported crude—and US refiners have ramped up their exports of refined products such as gasoline and diesel. As a result, US net oil imports of crude and products have declined almost 20% in dollar terms, from $388 billion in 2008 to $239 billion in 2013.** This shift has lowered the overall US trade deficit to its lowest level in four years, despite annual average world oil prices during this time that have been at record historical levels. At the same time, the United States—which a few years ago was expected to be a major importer of LNG–is now gearing up to be a major exporter.

The US economy is still recovering from the Great Recession of 2008-2009 and its legacy of high unemployment. Without the boost to employment and income generated by unconventional oil and gas development—and the sustained low natural gas prices—the US economic climate would be much more difficult.

* http://www.ihs.com/info/ecc/a/americas-new-energy-future.aspx#tab-3
** EIA March 2014 Monthly Energy Review, Table 1.5.

IMPACT ON STATE ECONOMIES

In addition to an assessment at the national level, IHS developed regional macroeconomic outlooks for each of the 50 US states that are consistent with the national forecasts. This was accomplished using IHS' US regional econometric models for each state economy. State-level models are driven by local economic structures and conditions, as well as the national economic environment. Each state model was then re-simulated under each case.

The assumptions in the Base Production restricted trade environment for each state are consistent with the current IHS baseline macroeconomic outlook. This is then compared to a free trade policy in the same Base Production Case. The impact of free trade on each state economy is generated by distributing the national level production, investment, balance of payments, and demand for machinery and equipment, and other factors to the state level.

For the Potential Production Case, IHS regional models were simulated under a higher oil production trajectory to model the two alternative trade policies—restricted trade and free trade.

With free trade for both production cases, IHS Energy has identified the location of upstream capital investment. Each state's economic response to new construction, demand, and oil-sector activity has also been simulated in the state models. The results for each state characterize the difference between free trade and restricted trade in both the Base Production and in the Potential Production cases, including the impacts of direct upstream investment and production.

INCREASED OIL PRODUCTION AND CAPITAL INVESTMENT

Oil production is expected to increase in all major producing states with free trade in the Base Production Case. Initially, these increases are somewhat proportional to the state's current level of oil production. While the difference in oil production investment between free and restricted trade peaks in 2017 and moderates by 2030 for all states, individual growth patterns vary among the states. In particular, states that are emerging (or reemerging) as major oil producers will see oil production steadily increase through the entire forecast period, while increases in other states that are currently oil producers will taper off. The effect of free crude oil trade is even more pronounced in the Potential Production Case, with the increase in production concentrated in states where new production is being boosted by new technologies.

As at the national level, increases in oil production will require increased capital investment in drilling, completion, facilities, and gathering equipment. In the Base Production free trade environment, the investment difference peaks early in the period, but remains significantly higher than the investment difference with a restricted trade policy through 2030. The increase in capital spending under the Potential Production Case is even stronger and reflects differences in state ranking that depends on the production outlook.

TABLE 5.13
Producing States Difference in Capital Investment (Crude Oil): Base Production − Free Trade vs. Restricted Trade ($ million, nominal)

Top 10 Producing States	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Texas	24,702	25,313	21,185	16,665	16,861	16,444	17,944
Oklahoma	7,022	7,233	6,082	4,899	5,069	6,016	6,031
California	5,463	5,587	4,237	2,856	2,947	3,505	3,743
Kansas	3,502	3,577	2,770	1,943	1,993	2,269	2,431
Colorado	2,249	2,302	1,771	1,204	1,250	1,530	1,605
Louisiana	3,159	3,280	2,567	1,840	1,960	2,787	2,712
Utah	2,761	2,816	2,164	1,450	1,496	1,751	1,880
North Dakota	1,945	2,274	1,988	1,517	1,686	2,903	2,563
Wyoming	1,836	1,947	1,585	1,216	1,332	2,139	1,953
Montana	1,725	1,805	1,429	1,043	1,121	1,666	1,585
Top 10 Total	**54,364**	**56,134**	**45,780**	**34,634**	**35,716**	**41,009**	**42,448**
US Total	**59,805**	**61,816**	**50,287**	**37,926**	**39,230**	**45,764**	**47,113**

Note: The rank for all years is based on the 2017 ranking.
1. Average of the years 2021-2030.
2. Average of the years 2016-2030.
Source: IHS Economics

TABLE 5.14
Producing States Difference in Capital Investment (Crude Oil): Potential Production − Free Trade vs. Restricted Trade ($ million, nominal)

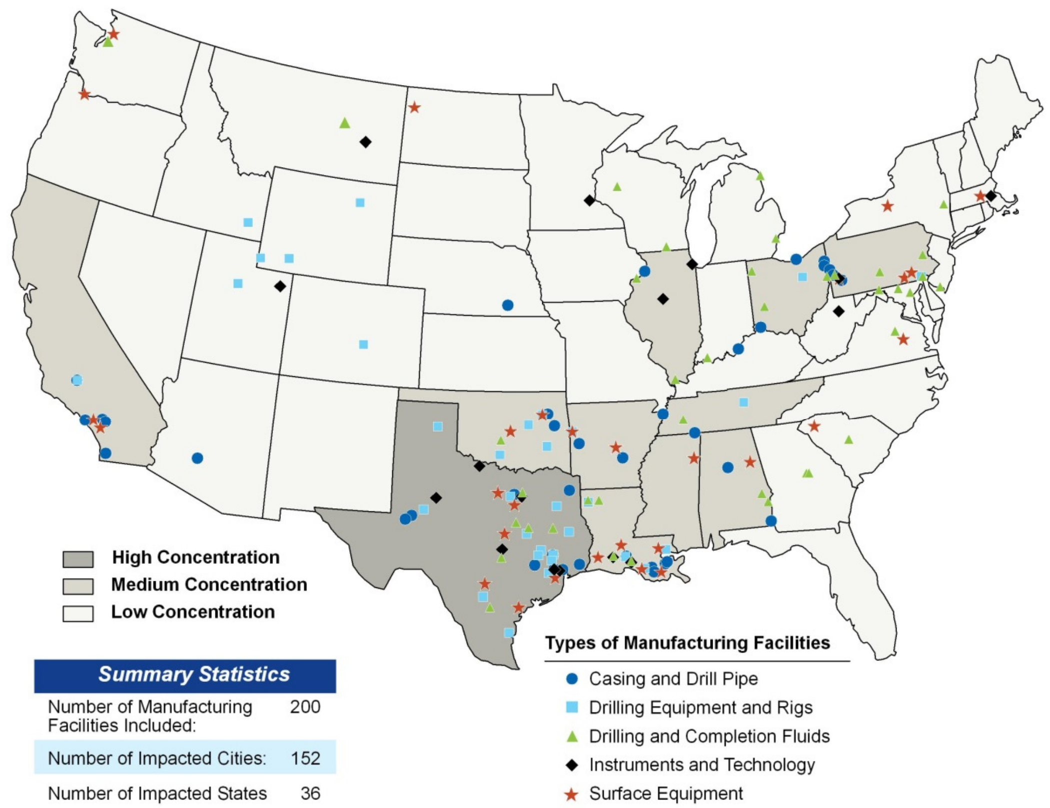
Top 10 Producing States	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Texas	31,060	33,542	27,889	20,990	21,953	25,110	25,769
Oklahoma	8,029	8,413	7,085	5,718	5,984	7,375	7,265
California	5,707	5,900	4,499	3,049	3,172	3,933	4,110
North Dakota	3,966	4,850	3,673	3,073	3,551	6,988	5,933
Kansas	3,827	3,956	3,081	2,179	2,254	2,660	2,793
Colorado	3,738	3,900	3,001	2,077	2,189	2,804	2,863
Utah	2,966	3,060	2,357	1,587	1,650	1,983	2,097
Louisiana	2,558	2,733	1,932	1,104	1,257	3,072	2,687
Wyoming	2,251	2,508	2,130	1,689	1,913	3,131	2,786
Montana	1,923	2,045	1,613	1,189	1,291	2,002	1,872
Top 10 Total	**66,024**	**70,907**	**57,261**	**42,656**	**45,213**	**59,056**	**58,175**
US Total	**73,343**	**78,798**	**63,597**	**47,298**	**50,251**	**66,021**	**64,900**

Note: The rank for all years is based on the 2017 ranking.
1. Average of the years 2021-2030.
2. Average of the years 2016-2030.
Source: IHS Economics

SUPPLY CHAIN IMPACT OF A FREE TRADE POLICY

What is less well known but is evident in the state-level analysis is that the oil and gas industry in the United States is supported by an extensive manufacturing and non-manufacturing supply chain, which keeps the industry well stocked in everything from rigs and drill pipe to surface separators, casing cement and engineering services. As shown in Figure 5.7 below, which highlights the manufacturing locations of the largest upstream equipment suppliers, the oil and gas manufacturing supply chain is spread out across the country, including many states—such as Illinois, Tennessee and Alabama—that are not large producers of oil and gas.

FIGURE 5.7
Major US Manufacturing Facilities that Supply the Oil and Gas Upstream Industry



Note: Figure based on a selection of major upstream equipment manufacturers and is not intended to be a comprehensive list of the vast array of equipment and supplies that each state manufactures for the upstream oil and gas industry.
Source: IHS Energy
40299-20

STATE-LEVEL ECONOMIC IMPACTS

Direct Employment

While the economic benefits of lifting the ban on oil exports are significantly positive for the entire United States, the benefits to the states are not spread equally. Not surprisingly, many of the gains accrue to major oil-producing states. Higher oil production and investment, spurred by increased demand, will immediately create more jobs in the natural resources and mining sector, which includes oil extraction. The increase in production will also require additional infrastructure to be built, adding construction jobs in the major producing states. The additional construction activity and jobs are more pronounced under a free trade scenario in both the Potential Production Case than in the Base Production Case.

Indirect Employment

Non-producing states will also benefit from the increased economic activity overall. In the short run, the added oil drilling and related construction activity will create demand for cement, chemicals and metals–especially steel–which are needed for hydraulic fracturing. Demand for professional, technical, and engineering services will also increase. While some of these manufacturing and non-manufacturing sectors are located in oil-producing states, economic activity will also spill over into other non-producing states that are part of the oil and gas industry's extensive supply chain.

In the Base Production Case, the gains in manufacturing employment in the free trade of crude oil, compared with restricted trade, peak in 2017 at nearly 100,000 jobs, before tapering off through the rest of the forecast period. While the gain is concentrated in major manufacturing states, led by Michigan, Ohio, and Texas, most states see some increase in manufacturing payrolls. In the Potential Production Case, the manufacturing boost that results from the free trade of crude oil peaks at 143,000 jobs in 2018, and then follows a similar tapering pattern.

Some sectors in the non-producing states, such as professional and business services and finance, will experience increased demand in firms specifically related to oil production, such as technical support, information technology and associated infrastructure, legal expertise, project financing and other financial services.

Total Employment

Ultimately, increases in gross state output will translate into higher employment in virtually every state, especially early in the forecast horizon. In Table 5.16, two states in particular–Texas and California–will each see increases in payrolls of more than 100,000 employees per year in the early investment phase associated with the free trade of crude oil in the Base Production Case. In the Potential Production Case (Table 5.17), the employment gains in Texas and California associated with free trade rise above 120,000 and 190,000, respectively.

TABLE 5.15
Difference in Total Employment: Base Production − Free Trade vs. Restricted Trade (thousands)

Top 10 States	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Texas	39.4	94.5	117.4	107.0	86.1	27.5	48.0
California	33.5	88.0	110.9	101.0	81.1	28.7	46.8
Florida	22.4	47.7	56.2	51.4	43.0	16.7	25.9
New York	16.4	37.3	44.9	40.4	32.9	11.8	19.3
Illinois	18.3	35.9	39.1	33.8	27.5	8.8	16.2
Ohio	15.1	30.1	33.3	28.9	23.7	7.7	13.9
Georgia	13.1	28.5	33.4	30.0	24.9	8.9	14.6
Michigan	14.9	27.7	29.0	24.1	18.9	4.8	10.8
Pennsylvania	11.5	24.7	28.2	24.8	20.3	5.7	11.1
North Carolina	11.2	23.9	27.9	25.5	21.4	5.9	11.3
Top 10 Total	**195.7**	**438.3**	**520.2**	**467.0**	**379.9**	**126.6**	**217.8**
US Total	**358.6**	**811.3**	**963.7**	**863.3**	**699.5**	**221.5**	**397.1**

Note: The rank for all years is based on the 2017 ranking.
1. Average of the years 2021-2030.
2. Average of the years 2016-2030.
Source: IHS Economics

TABLE 5.16
Difference in Total Employment: Potential Production − Free Trade vs. Restricted Trade (thousands)

Top 10 States	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
California	46.9	134.9	189.4	188.9	164.2	81.5	102.6
Texas	50.5	103.2	119.8	113.2	105.7	72.9	81.4
Florida	33.9	78.8	103.2	101.5	91.6	48.8	59.8
New York	25.4	61.4	80.9	79.2	70.1	35.4	44.7
Illinois	25.4	53.2	64.8	60.5	53.6	27.0	35.1
Ohio	21.2	46.7	58.6	55.6	49.3	24.0	31.4
Georgia	19.7	46.0	59.6	58.2	52.2	27.8	34.3
Pennsylvania	19.3	43.9	55.8	53.6	47.3	21.9	29.3
Michigan	20.4	41.7	49.9	45.6	39.8	16.8	24.4
North Carolina	16.8	39.1	50.9	50.0	45.2	20.7	27.3
Top 10 Total	**279.5**	**649.0**	**832.8**	**806.2**	**719.0**	**376.8**	**470.3**
US Total	**521.5**	**1,206.2**	**1,536.7**	**1,483.2**	**1,320.0**	**681.6**	**861.9**

Note: The rank for all years is based on the 2017 ranking.
1. Average of the years 2021-2030.
2. Average of the years 2016-2030.
Source: IHS Economics

Gross State Product

The increase in US oil production and the resulting business investment brought about by increased oil exports will boost all state economies. Since most of the industry's capital investment occurs early in the forecast horizon, the increase to gross state product is most pronounced in the short term. However, the impact remains noticeably positive for many years due to higher employment levels, especially the indirect jobs stimulated by the increase in production, investment, and supply chain activities. When moving from restricted trade to free trade in the Base Production Case, all states exhibit robust increases in gross state product. The corresponding change in the Potential Production Case is more that 20% stronger than in the Base Case.

TABLE 5.17
Producing States Difference in Gross State Product: Base Production − Free Trade vs. Restricted Trade
($ million, real)

Top 10 Producing States	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Texas	9,838	17,822	18,993	16,821	14,100	9,083	11,227
California	8,215	16,055	16,883	15,010	13,377	8,902	10,571
New York	4,058	7,184	7,045	6,288	6,049	6,190	6,168
Florida	3,316	5,976	6,033	5,374	4,916	3,059	3,747
Illinois	2,984	5,271	5,145	4,453	4,085	3,217	3,607
Ohio	2,116	3,546	3,312	2,824	2,648	2,003	2,298
Pennsylvania	1,994	3,420	3,211	2,749	2,576	1,751	2,098
Michigan	1,952	3,254	3,022	2,510	2,250	1,580	1,919
Virginia	1,688	3,220	3,279	2,856	2,569	1,446	1,872
Colorado	1,356	2,712	2,961	2,653	2,313	1,929	2,085
Top 10 Total	**37,517**	**68,460**	**69,884**	**61,537**	**54,884**	**39,160**	**45,592**
Producing States Total	**50,955**	**93,143**	**95,256**	**83,827**	**74,438**	**51,398**	**60,773**
US Total	**66,937**	**122,243**	**124,133**	**109,144**	**97,777**	**67,161**	**79,456**

Note: The rank for all years is based on the 2017 ranking.
1. Average of the years 2021-2030.
2. Average of the years 2016-2030.
Source: IHS Economics

TABLE 5.18
Producing States Difference in Gross State Product: Potential Production − Free Trade vs. Restricted Trade
($ million, real)

Top 10 Producing States	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
California	12,108	23,947	27,885	26,298	25,077	20,456	21,325
Texas	10,998	22,385	26,967	25,840	24,408	19,854	20,609
New York	6,316	11,286	12,401	11,550	11,536	12,699	12,005
Florida	5,049	9,285	10,452	9,785	9,537	7,202	7,742
Illinois	4,461	8,105	8,964	8,207	7,896	7,071	7,223
Pennsylvania	3,052	5,310	5,643	5,092	4,988	3,896	4,203
Ohio	3,115	5,406	5,784	5,209	5,104	4,451	4,608
Virginia	2,601	4,986	5,635	5,223	4,985	3,517	3,907
Michigan	2,795	4,828	5,131	4,535	4,344	3,509	3,781
Colorado	1,827	3,794	4,534	4,359	4,181	4,073	3,962
Top 10 Total	**52,320**	**99,332**	**113,396**	**106,099**	**102,056**	**86,727**	**89,365**
Producing States Total	**70,516**	**133,980**	**153,092**	**143,255**	**137,390**	**113,642**	**118,310**
US Total	**95,073**	**179,135**	**203,164**	**189,610**	**182,442**	**149,728**	**156,447**

Note: The rank for all years is based on the 2017 ranking.
1. Average of the years 2021-2030.
2. Average of the years 2016-2030.
Source: IHS Economics

TABLE 5.19
Non-Producing States Difference in Gross State Product: Base Production – Free Trade vs. Restricted Trade ($ million, real)

Top 10 Non-Producing States	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Georgia	1,920	3,545	3,605	3,168	2,859	1,618	2,085
North Carolina	1,888	3,376	3,366	2,992	2,781	1,534	1,983
New Jersey	1,669	3,018	2,996	2,621	2,419	1,658	1,954
Massachusetts	1,422	2,681	2,722	2,386	2,174	1,448	1,724
Washington	1,335	2,504	2,556	2,310	2,178	1,781	1,913
Minnesota	1,092	1,953	1,898	1,662	1,566	1,227	1,363
Maryland	1,035	1,902	1,865	1,606	1,459	906	1,129
Oregon	947	1,805	1,836	1,644	1,553	1,528	1,538
Wisconsin	1,046	1,774	1,646	1,379	1,247	625	889
Connecticut	797	1,455	1,426	1,249	1,166	992	1,068
Top 10 Total	**13,152**	**24,012**	**23,917**	**21,018**	**19,401**	**13,319**	**15,646**
Non-Producing States Total	**15,983**	**29,100**	**28,877**	**25,317**	**23,339**	**15,763**	**18,683**
US Total	**66,937**	**122,243**	**124,133**	**109,144**	**97,777**	**67,161**	**79,456**

Note: The rank for all years is based on the 2017 ranking.
1. Average of the years 2021-2030.
2. Average of the years 2016-2030.
Source: IHS Economics

TABLE 5.20
Non-Producing States Difference in Gross State Product: Potential Production – Free Trade vs. Restricted Trade ($ million, real)

Top 10 Non-Producing States	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Georgia	2,919	5,470	6,184	5,762	5,541	3,998	4,391
North Carolina	2,863	5,243	5,859	5,468	5,366	3,777	4,171
New Jersey	2,601	4,722	5,218	4,823	4,684	3,674	3,919
Massachusetts	2,203	4,178	4,715	4,370	4,207	3,284	3,501
Washington	2,078	3,908	4,425	4,214	4,172	3,934	3,876
Minnesota	1,676	3,032	3,308	3,044	2,995	2,689	2,730
Maryland	1,621	2,982	3,260	2,980	2,863	2,074	2,296
Oregon	1,446	2,768	3,147	2,968	2,938	3,295	3,081
Wisconsin	1,554	2,698	2,857	2,538	2,418	1,570	1,851
Connecticut	1,235	2,258	2,476	2,285	2,232	2,131	2,120
Top 10 Total	**20,195**	**37,260**	**41,450**	**38,452**	**37,417**	**30,426**	**31,936**
Non-Producing States Total	**24,557**	**45,156**	**50,072**	**46,355**	**45,052**	**36,086**	**38,137**
US Total	**95,073**	**179,135**	**203,164**	**189,610**	**182,442**	**149,728**	**156,447**

Note: The rank for all years is based on the 2017 ranking.
1. Average of the years 2021-2030.
2. Average of the years 2016-2030.
Source: IHS Economics

Government Revenue

Estimates of a state government's revenues include its respective federal and state contributions through personal and corporate taxes, as well as any federal and state bonuses and royalties derived from crude oil production in the state. In the Base Production Case, the top 10 producing states generate 75% of total government revenues collected by all 50 states over the forecast period (2016-2030) as a result of the increased production that comes from the change in crude oil trade policy. The corresponding share in the Potential Production Cases is very similar.

TABLE 5.21
Producing States Difference in Total Government Revenue: Base Production − Free Trade vs. Restricted Trade ($ million, nominal)

Top 10 Producing States	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
Texas	5,100	7,595	7,392	6,103	5,175	104,246	135,612
California	2,565	6,978	7,917	6,673	5,586	153,863	183,582
New York	1,303	3,484	3,953	3,372	2,975	89,231	104,319
North Dakota	2,939	2,702	2,422	2,069	2,094	31,373	43,600
Illinois	998	2,198	2,234	1,821	1,559	43,046	51,856
Florida	914	2,020	2,158	1,835	1,531	43,065	51,523
Ohio	730	1,620	1,678	1,378	1,170	30,699	37,276
Pennsylvania	644	1,549	1,664	1,407	1,234	35,804	42,301
Oklahoma	1,015	1,510	1,456	1,163	990	16,756	22,889
Michigan	710	1,423	1,374	1,071	873	22,508	27,959
Top 10 Total	**16,918**	**31,079**	**32,250**	**26,892**	**23,187**	**570,591**	**700,918**
Producing States Total	**24,083**	**43,781**	**45,082**	**37,778**	**32,516**	**799,404**	**982,644**
US Total	**28,888**	**55,769**	**58,188**	**48,891**	**42,124**	**1,077,224**	**1,311,085**

Note: The rank for all years is based on the 2017 ranking.
1. Total of the years 2021-2030.
2. Total of the years 2016-2030.
Source: IHS Economics, IHS Energy

TABLE 5.22
Producing States Difference in Total Government Revenue: Potential Production − Free Trade vs. Restricted Trade ($ million, nominal)

Top 10 Producing States	2016	2017	2018	2019	2020	2021-2030[1]	2016-2030[2]
California	3,616	10,341	13,434	12,697	11,272	346,460	397,820
Texas	6,944	10,196	10,504	9,053	8,649	230,393	275,738
New York	2,028	5,530	7,003	6,664	6,142	202,228	229,595
North Dakota	3,987	4,269	3,977	3,073	3,078	66,245	84,628
Florida	1,430	3,334	4,072	3,741	3,320	96,711	112,609
Illinois	1,454	3,324	3,877	3,502	3,179	97,736	113,072
Pennsylvania	1,080	2,655	3,213	2,974	2,682	82,204	94,808
Ohio	1,049	2,490	2,974	2,712	2,416	69,535	81,176
Virginia	815	2,251	2,796	2,568	2,263	69,872	80,565
Michigan	994	2,139	2,421	2,110	1,840	51,395	60,900
Top 10 Total	**23,397**	**46,529**	**54,271**	**49,093**	**44,841**	**1,312,779**	**1,530,910**
Producing States Total	**34,041**	**64,408**	**73,487**	**66,649**	**61,289**	**1,778,369**	**2,079,751**
US Total	**41,535**	**83,682**	**97,373**	**89,015**	**81,541**	**2,410,900**	**2,804,045**

Note: The rank for all years is based on the 2017 ranking.
1. Total of the years 2021-2030.
2. Total of the years 2016-2030.
Source: IHS Economics, IHS Energy

The largest economic gains from a lifting of the export restrictions on domestically produced crude oil will go to states directly involved in oil production. However, non-producing states that participate in the supply chain will also see considerable benefits. While the benefits of free trade will not be enjoyed equally by every state, the benefits of rising oil production and investment will find its way into virtually every state.

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