The Role of Canadian Oil Sands in US Oil Supply

SPECIAL REPORT

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About This Report

Purpose. This IHS CERA report is intended to offer an independent assessment of the potential role of Canadian oil sands in future US oil supply. Volatile oil prices, supply uncertainty, and concerns about global warming have intensified the worldwide debate about oil resource development. In North America this has pushed the debate on development of the Canadian oil sands to center stage. The outcome of this debate will determine the economic and political playing field for the oil sands industry and will have a broader impact on oil supply and energy security in the United States and beyond.

Context. This is the first in a series of reports from the IHS CERA *Canadian Oil Sands Dialogue.* The Dialogue convenes stakeholders in the oil sands to participate in an objective, transparent analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. Stakeholders include representatives from governments, regulators, oil companies, shipping companies, and nongovernmental organizations. The 2010 Dialogue program and associated reports cover four oil sands topics:

- the role of Canadian oil sands in US oil supply
- life-cycle greenhouse gas emissions
- oil sands technology: advances and outlook
- impact of greenhouse gas policies

The Dialogue builds on the foundation of IHS CERA's 2009 Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance.* The main report of the past study can be downloaded at www2.cera.com\oilsands.

Methodology. This report includes multistakeholder input both from a focus group meeting held in Calgary on Febuary 4, 2010 and from feedback on a draft version of the report. IHS CERA also conducted its own extensive research and analysis independently and in consultation with stakeholders. IHS CERA has full editorial control over this report and is solely responsible for the report's contents (see the end of this report for a list of participants and the IHS CERA team).

Structure. This report has four major sections, including the Key Implications:

- Key Implications
- Part I: Understanding US Oil Demand. How much energy will the United States require in the future, and how much of this demand will need to be met by oil?
- Part II: Assessing Potential US Oil Supply. Considering global oil demand, where could future US oil supply be sourced? What type of supply is likely to be available?
- Part III: A Role for Oil Sands in US Oil Supply. How competitive are the Canadian oil sands with other potential sources of new supply? What are other aspects of increased oil supply from Canada?

We welcome your feedback regarding this IHS CERA report. Please feel free to e-mail us at info@ihscera.com and reference the title of this report in your message.

For clients with access to **IHSCERA.com,** the following features related to this report may be available online: downloadable data (excel file format); downloadable, full-color graphics; author biographies; and the Adobe PDF version of the complete report.

THE ROLE OF CANADIAN OIL SANDS IN US OIL SUPPLY

KEY IMPLICATIONS

What is the role of Canadian oil sands in US oil supply today and in the future? Oil sands are already an important source of US oil supply, but the growth potential is much larger, as much as three to four times higher in 2030 than in 2009.

- **Oil will continue to play a critical role in future US energy supply.** In the United States oil accounts for over 40 percent of energy consumption. Despite an outlook for relatively flat US oil demand growth to 2030, the United States will maintain its position as the world's largest oil market over the next two decades. Oil will continue to be the largest source of transportation fuel during this time. Considering current technologies and costs, even with subsidies, oil alternatives such as biofuels, electric vehicles, and natural gas vehicles are more expensive than oil.

- **Over the next 20 years, both globally and within the United States, new sources of oil supply will be required.** Globally, to satisfy growing oil demand and offset declines from existing resources, new sources of oil supply are required. Over the past decade 70 percent of US imports have come from five countries—Mexico, Canada, Venezuela, Saudi Arabia, and Nigeria. In the next two decades it is likely that some of the top US suppliers will change. Some suppliers will be unable to maintain current levels of exports owing to declining production, growth in domestic demand, or expansion into new export markets. As rapid oil demand growth from the developing world keeps steady pressure on supplies, traditional US suppliers are likely to shift increasing shares of new production to these markets.

- **Oil sands offer the possibility of increasing North American oil supply security, with the potential to become the largest source of US oil imports.** Does the United States consider Canadian oil as foreign oil? "Foreign" implies geographically distant or unknown. By most measures Canada's oil is less foreign than other potential sources of supply. Oil supply from Canada is stable, proximate, connected by pipelines, and part of a limited set of oil development opportunities in which private oil companies—including US firms—can openly and securely invest. By 2030 in a high growth scenario oil sands could contribute 36 percent of total US oil imports. In a moderate growth case oil sands could grow to 20 percent of US oil imports, up from 8 percent today. Under both the low and high projections the Canadian oil sands play a key role in supplying the North American market.

- **Energy security does not need to be at odds with the environment.** Innovation in oil sands has been a constant theme. Since its inception, the industry has made and continues to make major technological strides in optimizing resources, innovating new processes, reducing costs, increasing efficiency, reducing greenhouse gas (GHG) emissions, and reducing its environmental impact. However, new techniques and technologies are needed to continue to grow production sustainably. Cooperation between governments, both in the United States and Canada, and the private sector is crucial to continued advancement of new technologies.

- **Oil sands are competitive with numerous other sources of oil supply.** Oil sands face the challenge of higher costs, but they are not alone in this regard. Comparing the economics of some of the world's largest sources of new oil supply, numerous projects are in the same economic range as oil sands.

—April 2010

THE ROLE OF CANADIAN OIL SANDS IN US OIL SUPPLY

> "Geography has made us neighbors. History has made us friends. Economy has made us partners. Necessity has made us allies."
> —John F. Kennedy, Address Before the Canadian Parliament in Ottawa, May 17, 1961.

What is the role of Canadian oil sands in US oil supply today and in the future? The answer to the first part of the question is clear: growth in oil sands production has been the main driver in making Canada the largest supplier, by far, of foreign oil to the United States. Oil sands production grew from 0.6 million barrels per day (mbd) to 1.35 mbd from 2000 to 2009, more than a twofold increase. This more than offset declines in conventional Canadian production and boosted US imports of Canadian crude oil from 1.4 mbd to 1.9 mbd in that time frame.* The more challenging question is about the future. Even if nothing changes, the oil sands, by virtue of their size today, will be an important source of supply for many years to come. But the growth potential is much bigger—volumes could be as much as three to four times higher in 2030 than in 2009. But how much of that potential will be realized is subject to a range of economic, political, and environmental variables.

The objective of this report is to provide an independent perspective on the future role of Canadian oil sands in US oil supply by identifying a credible range of outcomes—high and low—and the assumptions attached to each. The importance of the oil sands goes well beyond the borders of Alberta and the midwestern United States, the principal market for oil sands today. The oil sands are a vital element of the economic and political fabric that makes Canadian-US trade relations among the most important and mutually beneficial relationships in the world. The United States and Canada are each the other's largest trading partner, and energy is a significant part of this trade. The oil sands also make Canada one of the few countries in the Western Hemisphere that has the potential to significantly boost oil production in the next two decades. The potential gains of increasing output are evident, but environmental and social concerns need to be addressed in order to optimize the benefits to a broad range of stakeholders, including governments, oil sands operators, investors, local communities, nongovernmental organizations, and the general public.

The first two parts of this report focus on understanding US oil demand and assessing potential future sources of US oil supply. These provide the context for the final part of the report, in which we evaluate the future role for Canadian oil sands in US crude supply.

*Imports of refined products from Canada are not included in this figure.

Oil Sands 101

The immensity of the oil sands is their signature feature. Current estimates place the amount of oil that can be economically recovered from Alberta's oil sands at 170 billion barrels, second only to Saudi Arabia. Canada's oil sands are concentrated in three major deposits. The largest is the Athabasca, a large region around Fort McMurray in northeastern Alberta. The other two areas are Peace River in northwest Alberta and Cold Lake, east of Edmonton.

The oil sands are grains of sand covered with water, bitumen, and clay. The "oil" in the oil sands comes from bitumen, an extra-heavy oil with high viscosity. Because of their black and sticky appearance, the oil sands are also referred to as "tar sands." Tar, however, is a man-made substance derived from petroleum or coal. Oil sands are unique in that they are produced via both surface mining and in-situ thermal processes.

- **Mining.** About 20 percent of currently recoverable oil sands reserves lie close enough to the surface to be mined. In a strip-mining process similar to coal mining, the overburden (primarily soils and vegetation) is removed and the layer of oil sands is excavated using massive shovels that scoop the sand, which is then transported by truck, shovel, or pipeline to a processing facility.
- **In-situ thermal processes.** About 80 percent of the recoverable oil sands deposits are too deep to be mined and are recovered by drilling methods, In-situ thermal methods inject steam into the wellbore to lower the viscosity of the bitumen and allow it to flow to the surface. Two thermal processes are in use today: steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS).

Raw bitumen is solid at ambient temperature and cannot be transported in pipelines or processed in conventional refineries. It must first be diluted with light oil liquid or converted into a synthetic light crude oil. Several crude oil–like products are produced from bitumen, and their properties differ in some respects from conventional light crude oil.

- **Upgraded bitumen, or synthetic crude oil (SCO),** is produced from bitumen via refinery conversion units that turn very heavy hydrocarbons into lighter, more valuable fractions. Although SCO can be sour, typically, SCO is a light, sweet, bottomless crude oil, with API gravity typically greater than 33 degrees.
- **Diluted bitumen (dilbit)** is bitumen mixed with a diluent, typically a natural gas liquid such as condensate. This is done to make the mixed product "lighter," lowering the viscosity enough for the dilbit to be transported in a pipeline. Some refineries will need modifications to process large amounts of dilbit feedstock, because it produces more heavy oil products than most crude oils. Dilbit is also of lower quality than most crude oils, containing higher levels of sulfur and aromatics. Some dilbits contain high amounts of corrosive acid, as measured by the total acid number. The high acid content is thought to cause corrosion to refinery equipment. However, new research is concluding that bitumen, although high in total acids, may not be as corrosive as other crudes with similar total acid levels.*
- **Synbit** is typically a combination of bitumen and SCO. The properties of each kind of synbit blend vary significantly, but blending the lighter SCO with the heavier bitumen results in a product that more closely resembles conventional crude oil.
- **Dilsynbit** is a combination of bitumen and heavy conventional crudes blended with condensate and SCO, resulting in a product that more closely resembles conventional crude oil.

*Final Report CAPP-AERI TAN Project, prepared by Crude Quality Inc., released May 29, 2009.

PART I: UNDERSTANDING US OIL DEMAND

Oil is certain to play a critical role in future energy supply globally and in the United States. Today oil accounts for about 35 percent of global energy supply—the largest share of any form of energy. IHS CERA estimates that global oil demand, excluding biofuels, will grow from 84.2 mbd in 2009 to between 92 and 105 mbd by 2030. We developed these estimates by examining future demand through the lens of two scenarios that establish high- and low-end boundary conditions for demand.

A TWO-SPEED WORLD FOR OIL DEMAND GROWTH

In 2009 the United States consumed about 20 percent of world energy supply and 22 percent of world oil supply (excluding biofuels), representing about 24 percent of world gross domestic product (GDP). The United States will remain the largest oil market and one of the largest overall energy consumers for many years to come. However, demand in the rest of the world, especially in Asia, is increasing at a faster rate. For example during 2000–09 total oil demand in China nearly doubled, while US oil demand declined 10 percent. Nearly all of the growth in world oil demand is expected to take place outside of OECD countries—in emerging markets in Asia, the Middle East, Latin America, and Africa. This rapid oil demand growth in the developing world is likely to result in a reshuffling of world oil flows, with many of the traditional oil suppliers to the United States shifting some of their supply to the growth markets. In general IHS CERA believes that the OECD as a whole has passed "peak demand."

Transportation remains the one sector where oil retains a near-monopoly, in contrast to many other energy-intensive industries that are no longer fueled by oil. Thus oil demand growth depends primarily upon the transportation sector. Growth in demand for personal mobility is expected to be the primary driver of developing-world oil demand, as robust economic growth translates into both higher living standards and increased demands for transportation.

In the United States, on the other hand, the personal transportation market is mature. There are more vehicles than registered drivers, and population growth is expected to be modest. In the past two decades gasoline demand grew mostly in line with population growth, since the efficiency of the light-duty vehicle fleet was stagnant. Looking to the future, however, this picture is changing. Regulation will increase the efficiency of new cars and light trucks through the middle of this decade, and government policy will encourage increased sales of alternative vehicles, gradually improving the efficiency of the overall fleet. This efficiency increase is likely to cancel out growth in fuel demand resulting from population growth. However, the factors listed above will affect US oil demand slowly. A typical car is on the road for 12 to 15 years before it is replaced. Therefore, even a significant improvement in fuel economy standards or an improvement in the economics and sales of alternative vehicles takes years to have a significant impact on oil demand (see the box "How Competitive Are Today's Fuel and Vehicle Alternatives to Oil?").

How Competitive Are Today's Fuel and Vehicle Alternatives to Oil?

How competitive are today's transportation alternatives with gasoline and diesel? Cost is a key issue only if and when alternatives become "transformative technologies"—offering either more utility for the same price or the same utility for a lower price—will they start to win significant and enduring market share from gasoline and diesel for transportation.

Comparing today's economics and considering the effect of government incentives, transportation alternatives are still more expensive than oil (see Figure 1). Concerns about high energy prices, energy security, and global warming have resulted in more research and development of these technologies. In time new innovations could help these technologies to close the "cost gap" and win increased levels of market share. But even with increased acceptance, the affect of these technologies on gasoline demand will occur slowly owing to the long time horizon associated with replacing the existing vehicle fleet and the continued competitiveness of the internal combustion engine.

US OIL DEMAND: UNLIKELY TO SURPASS 2005 PEAK

Trends such as an aging population and increasing fuel economy standards put gradual downward pressure on US oil demand. As a result, overall oil demand in the United States has likely already peaked. US oil demand reached its high water mark in 2005 at 20.9 mbd (excluding biofuels)—well before the impact of the economic crisis—and has been in continuous decline since then. However, the end of the oil age in this large economy is hardly imminent. The United States will continue to rely strongly on petroleum. US oil demand is projected to be between 17.8 and 19.3 mbd by 2030 (excluding biofuels). Over the next 20 years the US will maintain its position as the world's largest oil market by a hefty margin (2030 US oil demand is projected to be at least 30 percent higher than China's).

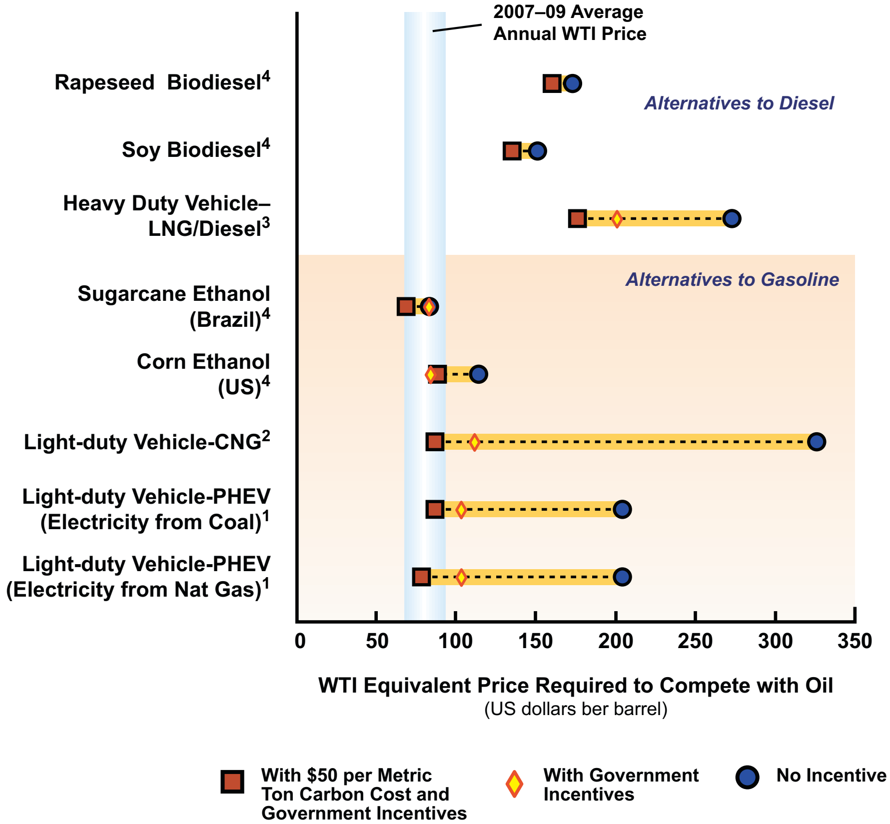
Elements of US Oil Demand

In 2009 gasoline, excluding ethanol, accounted for 46 percent of total US petroleum demand, the largest component of transportation-related demand (see Figure 2). Even if US gasoline demand disappeared overnight, the United States would still consume nearly 10 mbd of oil with limited prospects for replacing the "nongasoline" portion of demand. Commercial-scale alternatives to diesel and jet fuel are not expected to arrive over the next two decades. Diesel will continue to be the workhorse of heavy truck freight hauling, and jet fuel will continue to power aviation. Indeed there is every reason to expect diesel demand to continue growing in any scenario featuring economic growth. Shipping may make the transition from heavy bunker fuel oil to greater volumes of diesel, but it is unlikely to move away from oil entirely.

The nontransport portion of US oil demand is also expected to change only slowly owing to a lack of alternatives. During the previous large decline in oil demand, from 1979 to 1983, total petroleum demand in OECD countries fell 7.5 mbd. But over half (4.1 mbd) of this decline in oil demand occurred as the nontransportation sectors of the economy—essentially the industrial and power sectors—permanently replaced residual fuel with coal, natural gas, and nuclear power. This massive shift was a one-time event.

Figure 1

Relative Economics of Transportation Alternatives to Oil



Source IHS CERA, analysis for alternative vehicles based on the levelized cost per mile traveled compared with costs of alternatives assumes 100 percent debt financing for all vehicles over 5 years, at a 7 percent interest rate with 40 percent residual value at the end of the loan period. Biofuel options based on production costs.

1. Plug-in hybrid electric light-duty vehicle (PHEV) averages 50 mpg, runs 67 percent of the time in electric mode, capital cost is $10,000 more than comparable gasoline vehicle, electricity costs $0.114 per kWh. Government incentive is $3,700.
2. Compressed natural gas (CNG) light-duty vehicle averages 28 mpg, fuel cost is 30 percent lower than gasoline, cost is $6830 more than comparable gasoline vehicle. Government incentives $4,000.
3. Heavy-duty vehicle (HDV) class 8 LNG/diesel. Extra costs for increased refueling and trip length are US$0.08 per mile. Capital cost for truck is $70,000 more than comparable diesel option, and government incentive is $32,000.
4. Average of feedstock prices from 2007 to 2009. Government incentive for corn based ethanol is $0.45 cents per gallon. Includes correction to account for lower energy content of ethanol and biodiesel.

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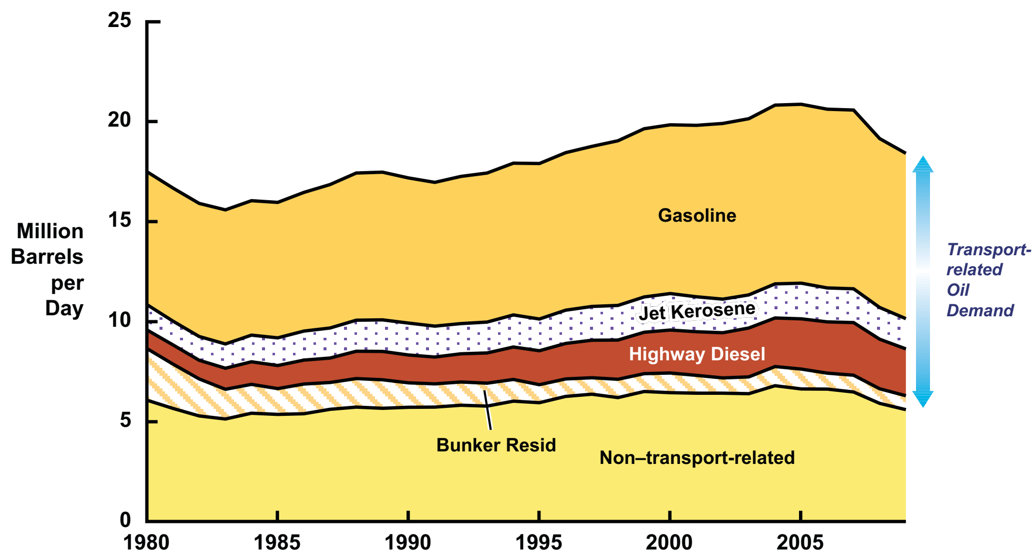
Today nontransport demand for oil primarily stems from uses such as petrochemical feedstocks, home heating, lubes, waxes, and asphalt, which have experienced only slight declines in demand over the past decade. Looking to the future, some nontransport demand will be lost as natural gas is substituted for distillate fuel in the residential, commercial, and industrial sectors and as the US petrochemical sector production declines. Other uses are expected to grow slightly, however, leaving overall demand flat.

Figure 2

Breakdown of US Oil Demand



Source: IHS CERA.
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US Gasoline Demand: A Sharp Decline

To date US government efforts to reduce oil demand have focused primarily on reducing the largest component of demand, gasoline consumption. Government actions aimed at reducing gasoline demand include efforts to increase biofuels consumption, higher vehicle fuel efficiency standards, incentives to encourage consumers to purchase alternative vehicles, and the ongoing funding of research and development.

Within this analysis IHS CERA considers two possible cases resulting in higher or lower US gasoline demand; the range is determined by both the success of government programs and the technological advancement of alternative fuels and vehicles.

IHS CERA's low gasoline growth case considers the impact of strong penetration of biofuels, slowing of growth in how much people drive, aggressive commercialization of plug-in hybrid electric vehicles (PHEVs), some dieselization of the light-duty vehicle fleet, and the further ratcheting up of strict fuel economy standards for new vehicles.* As a result US petroleum-based gasoline demand declines by 35 percent (or 3 mbd) from 2005 to 2030 (see Table 1).

In the low gasoline growth case almost one third of the lost gasoline demand is driven by a near doubling in the fuel economy standards for new vehicles. Over 0.2 mbd of gasoline demand is avoided by increasing numbers of PHEVs, but the largest driver of reduced gasoline demand is the contribution of 1.9 mbd of ethanol by 2030—an almost threefold

*PHEVs have an all-electric range large enough to handle most day-to-day driving, with a backup conventional fuel tank to ensure a range as great or greater than that of a gasoline vehicle.

Table 1

Drivers of US Gasoline Demand

	Current	Low Gasoline Growth Case (2030)	High Gasoline Growth Case (2030)
Ethanol production	0.8 mbd	1.9 mbd	1.5 mbd
US ethanol consumption by feedstock	0.8 mbd corn	1 mbd corn 1 mbd sugar cane and next generation	1 mbd corn 0.5 mbd sugar cane and next generation
New vehicle fuel economy standards (new CAFE standards) passenger miles per gallon of gasoline	Cars = 27.5 Light trucks = 21.4	Cars = 50 Light trucks = 40	Cars = 45 Light trucks = 35
Change in Vehicle Miles Travelled (VMT)	1.7 percent per year (1980–2005 average)	1.1 percent per year (2010–30 average)	1.3 percent per year (2010–30 average)
Percent of new vehicle sales from PHEVs in 2030	0 percent	25 percent	10 percent
Reduction in US petroleum-based gasoline demand from 2005 to 2030		Down 35 percent (or 3 mbd)	Down 20 percent (or 1.7 mbd)
US gasoline demand, excluding biofuels (mbd)	8.3	5.9	7.2

Source: IHS CERA.

increase from the current level. Achieving this volume of ethanol production clearly presents a challenge. The successful development of next generation biofuel production is a crucial hurdle, but not the only one. Ethanol production levels could be constrained by both water and land limits. New biofuel production processes must reduce water consumption and use feedstocks that are both sustainable and scalable.*

Incorporating such large amounts of biofuels into transportation fuel will also be a challenge. Although a portion of the ethanol could be seamlessly blended into conventional gasoline, a significant volume—perhaps as much as 1 mbd—would need to be consumed in flex-fuel vehicles (FFVs) in the form of ethanol blends such as E85 (85 percent ethanol and 15 percent gasoline).** Both the sales of FFVs and the development of the infrastructure to distribute E85 fuel would have to accelerate, fueling stations would need to install new tanks and pumps, and consumers would have to buy growing numbers of FFVs and choose to fill up with E85. However, even the volumes of ethanol consumed in this "stretch" scenario fall

*Since ethanol refineries consume three to four liters of water for every liter of ethanol produced, water availability could become a limiting factor in some regions where ethanol refineries are sited. Depending on the feedstock used and the associated water and land limits, the final production levels could be constrained.

**In both the high and low growth scenario the maximum allowable volume of ethanol that can be blended into conventional gasoline (also known as the ethanol "blend wall") is increased from the current limit of 10 percent to 15 percent.

short of the 2.35 mbd of biofuels currently mandated by the US Renewable Fuel Standard (RFS) by 2022.*

IHS CERA's high gasoline growth case assumes that the US government adopts less challenging goals for reducing gasoline demand and that technology does not progress as quickly. US petroleum-based gasoline demand declines in this case also, by 20 percent (or 1.7 mbd) from 2005 to 2030. Ongoing penetration of ethanol; slowing growth in vehicle miles traveled per driver; increased fuel efficiency; and adoption of some alternative vehicles, including PHEVs in the later years, contribute to the demand decline.

The high-growth case assumes that about 300,000 barrels per day (bd), or 0.3 mbd of E85, will be consumed in FFVs. At this lower consumption level, implementation issues related to retail distribution of ethanol and the corresponding FFVs are less daunting.

*The RFS is a federal mandate to increase US consumption of biofuels. The RFS caps the volume of ethanol derived from corn starch at 0.98 mbd by 2015. By 2022, 1.37 mbd more is targeted to be consumed and this fuel is regulated to be derived from noncorn feedstocks. The majority of this noncorn volume—1 mbd—is regulated to be derived from cellulosic biomass (such as switchgrass, corn stover, or wood chips).

PART II: ASSESSING POTENTIAL US OIL SUPPLY

From 2003 to 2007 growth in global oil demand surged forward each year while oil supply struggled to keep pace. The narrow balance between oil supply and demand was a key factor in the steady price rise over this period. By 2008 the cumulative impact of record-high oil prices and a severe recession led to a decline in world oil demand for the first time since 1979. In 2009 demand fell again. In total oil demand fell 1.9 mbd in 2008 and 2009, resetting oil demand back to 2005 levels and erasing four years of growth. But oil production capacity, which had struggled to keep up with demand for several years, was still expanding. By 2010 global spare oil production capacity (the difference between the amount of oil demanded and production capacity) grew to more than 6 mbd—a threefold increase over the thin spare capacity volumes tracked for much of the preceding decade.

How long will the current generous cushion of spare oil production capacity last? Much depends on the progress and pace of recovery from the Great Recession and the ability of oil companies and governments to "stay the course" and continue investing even in the face of the current oversupply.

US CRUDE SUPPLY TODAY

Since the United States became a net importer in the late 1940s, it has relied on foreign oil to make up the gap between domestic supply and demand. In 2009 close to 40 percent of US petroleum demand was satisfied by domestic production. The remainder was imported from over 40 countries. Although foreign oil comes from many suppliers, over the past decade 70 percent of crude oil imports have been sourced from five countries (see Table 2).

Often unremarked and indeed unrecognized, Canada sits at the top of the list of foreign suppliers. Canada's share of US crude oil imports rose from 15 percent in 2000 to 21 percent in 2009, underscoring the deep and growing economic and trading relationship between the two neighbors. US total crude oil imports from Canada were 1.9 mbd, and the Canadian oil sands alone contributed half of this supply. In third quarter 2009 oil sands imports hit a new high water mark, totaling over 1 mbd.* In third quarter 2009 oil sands supply alone was the third largest source of crude oil imported to the United States (see the box "Different Yardsticks: Measuring Importers' Share of US Oil Supply"). The growing importance of oil sands in US oil supply is evident.

Over the years while imports from Canada increased, imports from other top suppliers have been in decline. From 2004 to 2008 combined imports of Mexican and Venezuelan crude dropped from 3.2 mbd to 2.5 mbd. A more conducive investment climate for oil production in both Mexico and Venezuela would be required to reverse the current trend of production decline.

*Assumes that over 120,000 bd of bitumen were supplied in dilsynbit blends, which are classified as conventional heavy crude.

Table 2

Comparison of US Crude Oil Imports, 2000 and 2009

(top suppliers)

2000

		Volume (mbd)	Share of US Imports (percent)
1	Saudi Arabia	1.5	17
2	Canada	1	15
3	Mexico	1.3	14
4	Venezuela	1.2	13
5	Nigeria	0.9	10

2009

		Volume (mbd)	Share of US Imports (percent)
1	Canada	1.9	21
2	Mexico	1.1	12
3	Saudi Arabia	1	11
4	Venezuela	1	11
5	Nigeria	0.8	9

Source: IHS CERA, US EIA.

Different Yardsticks: Measuring Importers' Share of US Oil Supply

The measure of the imports by country or supply source varies depending on the yardstick used. Three common measures are defined as follows:

- **Imports as a percentage of total US oil supply.** Compares the import volume to the total volume of US domestic and imports of crude oil, refined products, and light hydrocarbon liquids (condensates and liquefied petroleum gases). In the high-growth oil sands scenario oil sands provide 26 percent of total US oil supply by 2030.
- **Imports as a percentage of US oil imports.** Compares the import volume to the total volume of US imports of crude oil, refined products, and light hydrocarbon liquids (condensates and liquefied petroleum gas). In the high-growth oil sands scenario oil sands account for 36 percent of total US oil imports by 2030.
- **Imports as a percent of US crude oil imports.** Compares the import volume to the total volume of imported crude oil only. In the high-growth oil sands scenario oil sands constitute 47 percent of total US crude oil imports by 2030.

Not only have the sources of US supply been shifting, the types of crudes available are also changing. Since 2004 the supply of medium and heavy crudes has been tightening. This trend of decreasing volumes of heavy crudes is bumping up against an ongoing expansion of US coking capacity, further exacerbating the tight market. Declines in the supply of heavier crudes have been driven by a number of factors: declines in domestic supply, declines in Mexican and Venezuelan production, and supply declines from other smaller exporters, and more recently the growing tightness has been reinforced by OPEC's decision to reduce crude production—especially the heavy and medium grades—in response to the recession and lower oil demand.*

SUPPLY GROWTH UNCERTAINTY

How much oil supply growth can the world expect over the next two decades? Examination of the resource base on a field-by-field basis indicates that there is ample potential for supply to meet demand to 2030 and beyond. IHS CERA estimates that oil production capacity will reach 96 to 110 mbd by 2030. To reach these supply levels, over the next two decades the oil industry would need to add between 2.8 and 3.5 mbd of new productive capacity each year or, put another way, add four to five oil-producing jurisdictions the size of Saudi Arabia over the next 20 years.**

The high-end estimate assumes that no major disruptions or investment shortfalls occur. The low-end estimate could result if oil supply difficulties, such as project delays, high costs, labor and equipment shortages, or production disruptions in important oil-producing countries, limit production growth. Sustained high prices and a significant market response toward alternative fuels and technologies would result in such an environment.

Where Will Future US Supply Come From?

Assuming that projected growth in global supply is achieved, IHS CERA estimates that the oil supply available to the United States from both domestic production and imports will be over 20 mbd by 2030, surpassing demand.***

Over the next 20 years the list of top US crude suppliers is likely to change (see the box "Production Outlook for Top US Crude Suppliers"). Some suppliers will be unable to maintain the current levels of exports to the United States owing to declining production, growth in domestic demand, expansion into new export markets, or a combination of the above.

In the United States new oil developments in the deep water of the Gulf of Mexico, other offshore plays, Alaska, and onshore plays such as the Bakken in the northern plains are projected to add new oil supply. Over the next decade on average over 150,000 bd of new

*For the purposes of this analysis heavy crudes are defined as those with an API gravity of less than 27 degrees, medium grades have an API gravity between 27 and 36 degrees, and light crudes have an API gravity greater than 36 degrees.
**Assumes a 4.5 percent per year decline in production from existing conventional reservoirs. Supply from the production of existing heavy oil, coal-to-liquids, biofuels, and gas-to-liquids supplies are not projected to decline.
***This assumes that imports from each country that currently supplies crude to the United States change in direct proportion to the expected overall supply change for that country. Exceptions include suppliers projected to have large increases in crude supply over the next 20 years (over 1 mbd), such as Iraq, Brazil, Saudi Arabia, and Canada.

Production Outlook for the Top US Crude Suppliers

Canada. Although oil sands production has expanded rapidly in recent years, the future rate of growth is uncertain because of differing views on the environmental impact of oil sands development and project economics. IHS CERA's oil sands scenarios envision a high growth case of 5.7 mbd and a moderate growth case of 3.1 mbd by 2030. Historically the United States has been Canada's only crude market, but this situation could change in the future. Plans to build a new pipeline to Canada's west coast are progressing. If this project continues on course, by 2017 over 500,000 bd of crude could be flowing to the Asian market from Canada.

Venezuela. Oil production has fallen since hitting a peak of 3.2 mbd in 1997. In 2009 oil production stood near 2.5 mbd. Although Venezuela has awarded new blocks in the Orinoco Oil Belt, there are execution challenges. IHS CERA anticipates that by 2020 production could grow again, and by 2030 levels will be about equal to current production. A risk to future US imports is the possibility that larger portions of Venezuelan crude could go to other markets, such as China.

Mexico. Mexico could become a net importer of oil in the latter part of this decade, assuming the current rate of production decline (primarily the result of declines in the Cantarell field), a continued increase in domestic oil demand of approximately 2 percent per year, and minimal development of new supply.

Saudi Arabia. Saudi Arabia has completed a program of increasing oil production capacity, raising capacity to 12.5 mbd. The next project, Manifa, is not planned for production until 2014. With the start-up of Khurais at 1.2 mbd in 2009, Saudi Arabia has brought onstream one of the largest projects ever. Given the ample spare capacity due to decreased oil demand from traditional export locations and an outlook for long-term flat oil demand growth in the developed world, Saudi Arabia has been actively seeking to grow exports to new growth markets in China and India for some time.

Nigeria. Nigeria continues to struggle with producing at capacity owing to security challenges, which have caused a sizable portion of supply to be shut in. New offshore developments should help to offset declines, and the outlook is for relatively flat production capacity over the next 20 years.

domestic productive capacity is projected to be added each year. Despite this growth in new capacity, overall domestic supply is relatively flat as new production works to offset the declines from the existing fields. US liquids production, excluding biofuels, should average over 7 mbd over the next decade—just above where it is today.

Despite the existence of ample supply potential, rapid oil demand growth in the developing world will keep steady pressure on supplies. Traditional US suppliers are likely to shift increasing shares of new production to these growth markets. If production growth is robust, this should not affect the United States. However, if the oil markets experience shortages anywhere in the world, either through a loss of supply or delays in supply growth, the effects will quickly reverberate to all crude importers.

Even among the largest US suppliers, there are numerous downside risks to IHS CERA's supply outlooks. What if supply growth from the oil sands is less than projected? What if some of Canadian supplies are diverted to Asia? What if new volumes of heavy crude from

Latin America do not materialize or countries divert increasing volumes of exports to Asia? What if technical challenges in ultradeep water projects slow production growth? If these downside risks unfold, IHS CERA estimates that the United States would drop between 3.5 to 4 mbd of the projected crude supply by 2030. Admittedly not all of these circumstances are likely to unfold, but they are all possible.

Spotlight on the "O-15"

IHS CERA compiled the "O-15"—the top 15 countries in terms of the potential to increase oil production over the next decade (see Figure 3). The rankings shift over time; currently Canada ranks eighth. Examining Canada's characteristics within the context of the O-15 provides insight into Canada's role as a long-term future supplier of crude oil to the United States.

- **Of the O-15, Canada has among the most, if not the most, open oil and gas investment climate.** No company enjoys a privileged position because of state ownership.

- **Canadian oil sands capacity is not government controlled.** The balance between governments and companies in the global oil industry has shifted toward governments. In

Figure 3

The O-15: The 15 Countries with the Most Potential to Increase Oil Production to 2020

Source: IHS CERA.
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the next decade nearly 70 percent of planned new productive capacity will be owned by government interests (through either a government joint venture partnership or ownership of a project by a national oil company). Of the 30 percent of non–government-controlled new capacity, one tenth of this supply comes from the Canadian oil sands.

- **Canada is a neighbor in many ways.** Among the O-15 Canada is the closest in proximity and policy to the United States.

- **At the project level, government regulation of Canadian oil developments is among the most robust in the world.** Relative to traditional suppliers (Venezuela, Mexico, and Canada) most new productive capacity is distant from the United States. Canada and Brazil are the only countries in the Western Hemisphere included in the O-15.

- **Canada has the capacity to grow heavy crude supplies.** Canada, Iraq, Kuwait, and Saudi Arabia are the only countries in the O-15 projected to add new heavy crude oil supplies. Heavy crudes are an important part of the feedstock mix for US refineries.

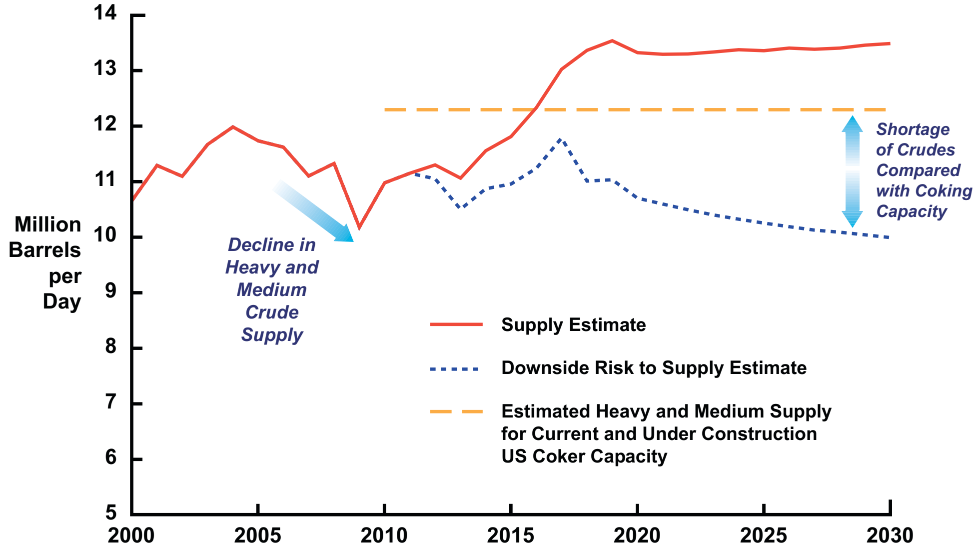
Will Available Crude Oil Match Refiners' Needs?

In IHS CERA's downside risk analysis, in which the United States would need to find between 3.5 and 4 mbd of additional crude supply, nearly half of the global supplies at risk are heavy crudes; the remainder are medium crudes. The loss of these supply sources would further exacerbate today's tight market for heavy and medium crudes in the United States. The US refining infrastructure is complex, making it well suited for heavier crude slates; and the complexity is still growing. Based on known projects already under construction or likely to proceed, US coking capacity is expected to increase by over 300,000 bd from 2009 to 2013. To capitalize on these costly upgrading investments and maximize refined product production, US refiners will need heavy and medium crudes (see Figure 4 and the box "Implications of a Shortfall of Heavy Crude Oil Supply for US Refining Industry").

Even with the base case supply outlook—not considering the downside risk analysis—the trend of declining supplies of medium and heavy crudes and increasing coking capacity is expected to keep the market for heavier crudes tight until 2015 or 2016. At that point stabilized Venezuelan production and substantial growth in Canadian oil sands supply converge with growth in medium and heavy supply from the United States, Brazil, Saudi Arabia, and Iraq to unravel the tightness in the market and the competition for these crudes.

Figure 4

Supply of Heavy and Medium Crude Oil to the US Market



Source: IHS CERA.
Note: The downside case considers the effect of possible delays in supply growth from traditional US suppliers. Downside risks includes effects from slow growth in Canadian oil sands, delays in ultradeepwater developments, diversion of some supply to new growth markets, and possible declines in supplies from Latin America.
00204-23

Implications of a Shortfall of Heavy Crude Oil Supply for US Refining Industry

What are the implications of a shortfall of heavy and medium crude supply for the US refining industry? Half the refineries in the United States have cokers, compared with one in six in Europe. Cokers are sophisticated reactors that upgrade the heaviest crude fractions into valuable light products. Because cokers are most efficient at processing heavy crudes, a shortage of heavier crudes will affect the mix of transportation fuels produced by US refiners.

Heavy crudes naturally yield a high proportion (50 percent or more) of heavy fractions that are upgraded essentially broken down or refined into products by refinery reactors (cokers and crackers). These reactors produce diesel and gasoline from the heavy crude fractions.

Light crudes naturally yield a high proportion (60 percent or more) of light crude fractions. After upgrading product quality, these fractions are used directly for transportation fuels.

A coking refinery configured for heavy crudes faces two problems when processing lighter crudes:

- Light crudes yield more light products, which overfills the units that upgrade transportation fuel quality (motor octane, sulfur removal, etc.).
- Light crudes yield less heavy products, and the refinery reactors used for upgrading are underutilized.

The result is a reduction in the volumes of gasoline and diesel produced. In the near term if a refiner configured to process heavy crude is forced to process 100 percent lighter crudes, the volume of gasoline and diesel produced can decrease by 15–20 percent, and refinery profitability also declines. In reality if forced to run light crudes over the longer term, the refiner would be forced to make refinery modifications to accommodate the new feedstock.

Bitumen from the Canadian oil sands is heavier than most other crudes supplied to the United States. Bitumen could offer feedstock flexibility to US refiners. When bitumen is blended with conventional crudes, the resulting mix "fits" well into a refinery configured for conventional heavy crudes. The volumes of produced transportation fuels are maintained and, in many cases, increase—often diesel volumes are boosted. However, to process increased volumes of bitumen, some refineries would require modifications.

*Bitumen has unique properties, such as high amounts of sulfur and high yields of middle distillates, that may require some modifications to the refinery.

PART III: A ROLE FOR OIL SANDS IN US OIL SUPPLY

Enhancing US supply security is critical so that oil and other forms of energy are catalysts, not hindrances, to economic growth. History illustrates the affects of oil shocks. From 1950 to 1990 there were six major disruptions in oil supply resulting in oil price increases that reduced the growth of the US economy. In each shock panic and expectations of conflict also drove price increases.

More recently the "new oil shock" sent oil prices from $30 in 2003 to $147.27 in 2008. This oil shock was brought on not by a single event, but by a convergence of factors: the narrow balance between oil supply and demand, political tensions in several major exporting countries, increasing development costs for new oil supply, and the growing influence of investors and financial markets on the price of oil. High prices forced oil demand to the breaking point—and demand finally weakened. In the United States and around the globe the financial crisis compounded the oil shock's effects, resulting in the worst economic downturn in more than 50 years.

The oil sands offer the United States the possibility of greater oil supply security. The ultimate pace of oil sands growth and the amount available to the US market will hinge on finding the appropriate balance between protecting the environment and realizing the full economic and energy security potential of the oil sands resource.

ECONOMICS OF OIL SANDS COMPARED WITH OTHER SOURCES OF OIL

The oil sands, like many other complex oil projects around the world, face the challenge of high development costs. Although oil sands costs are roughly comparable to those of some other large potential sources of new supply, they are higher than many projects in the Middle East and other low-cost producing regions. Even considering a strong move to oil alternatives, meeting global oil demand over the next 20 years will require that the full portfolio of oil development projects, including expensive sources of supply, are brought online around the world.

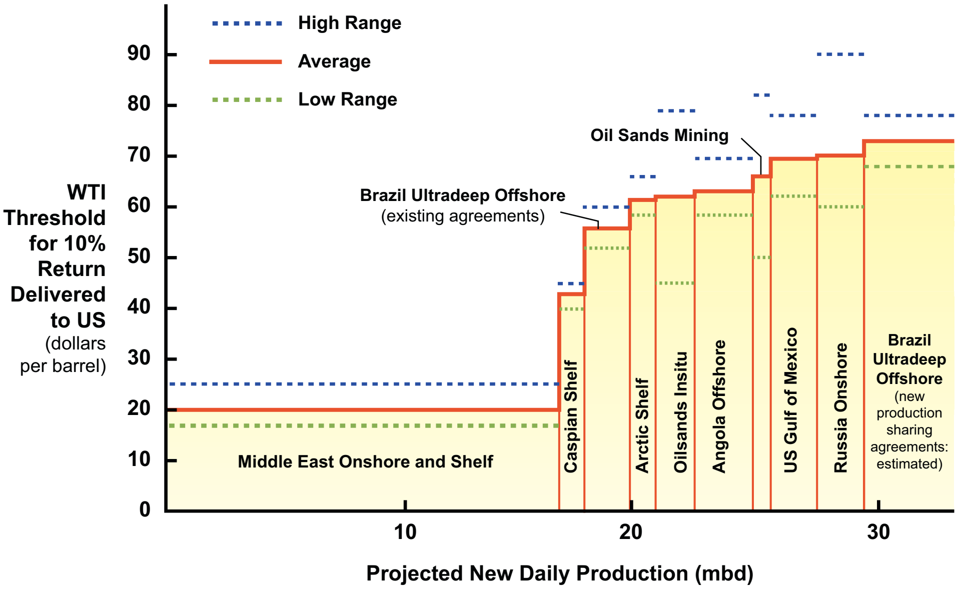
The list of potential oil development projects is long. How do some of the largest projects—ones with the greatest ability to add new productive capacity over the next five to ten years—compare with the economics of oil sands?

Figure 5 compares the economics of a number of oil development projects, evaluating the threshold West Texas Intermediate (WTI) equivalent price required to obtain a 10 percent return on the capital investment. The new oil developments compared are substantial, representing over 34 mbd of new productive capacity—as much as half of the total new capacity required to meet the 2030 high oil demand projection.

The economic analysis of each development project considers each country's royalties, taxes, government take, sustaining capital, variance in heavy and medium crude prices, transportation costs to deliver the crude to the US market, reserve sizes, current range of capital costs (assuming no future cost escalation from third quarter 2009), and operating

Figure 5

Range of WTI Threshold Costs for New Crude Supply



Source: IHS CERA.
Note: Comparison of current economics of major new supply planned over the next 5 to 10 years. Compares the threshold WTI-equivalent price of each development by calculating the oil price required to obtain a 10 percent return on the capital investment over the life of the project, including the transportation costs to deliver the crude to the US market. For oil sands projects, the economic range considers the range of economics for both integrated investments (producing upgraded synthetic crude oil or refined products) and upstream-only investments (producing dilbit). Costs are on the low range for jurisdictions that use production-sharing or profit-sharing types of agreements, which are applicable only when the projects profit (not at breakeven point). Russian onshore projects assume current upstream and export tax regimes are in effect. Threshold prices for Brazil ultradeep offshore new production-sharing agreements and productive capacity are both estimated as there have not been any contracts awarded under these new terms.
00204-21

costs. For oil sands projects the economic range is quite large—it considers the range of economics for both integrated investments (producing upgraded synthetic crude oil or refined products) and upstream-only investments (producing dilbit). A cost for carbon emissions is not included for any of the projects compared.

Oil sands face the challenge of higher costs, but they are not alone. A comparison of the costs of some of the world's largest sources of new oil supply reveals that numerous projects are in the same economic range as oil sands.

A ROLE FOR OIL SANDS IN NORTH AMERICAN ENERGY SUPPLY

The magnitude of the oil sands resource, the second largest recoverable oil reserve in the world at 170 billion barrels (with the potential to grow many times larger as technical advancements unlock more of the resource), makes the oil sands significant in the context of global energy security. The sheer size of the resource, combined with one of the world's most open oil and gas investment climates, puts the oil sands in a shrinking group of oil development opportunities in which private sector oil companies, including US firms, can openly and securely invest.

But how will oil sands evolve in the context of US oil supply? The pace of the development could take many trajectories. IHS CERA envisions oil sands production ranging between 3.1 and 5.7 mbd by 2030. Although oil sands production alone will not meet all the world's energy needs (the range would equate to about 3 to 5 percent of global petroleum supply), it has the potential to increase US energy security dramatically while providing an engine of economic growth for the US and Canadian economies. Oil sands production of 5.7 mbd would supply 36 percent of US oil imports by 2030, compared with 20 percent in a moderate oil sands growth case and 8 percent today.

The Obama Administration's energy policy has the stated goal of decreasing dependence on foreign oil. In fact since the first oil shocks the desire for energy independence has been a constant theme in US energy policy. But does the United States consider Canadian oil foreign? Foreign implies far-off or unknown. By most measures, Canada is less foreign than other sources of supply—Canada and the United States have a highly efficient and integrated energy trade, moving electricity, natural gas, and oil efficiently, every day, via an interdependent network of transmission grids and pipelines.

Canada is a strong ally of the United States with over $1.5 billion of goods traded each day over the border. Canada is also a trusted partner on security matters.*

The United States will continue to rely on imported oil into the foreseeable future. Sourcing increasing volumes of oil from Canada offers the possibly of increasing North American oil supply security.

CONTRIBUTION OF OIL SANDS TO THE NORTH AMERICAN ECONOMY

The growth of oil sands production in the past decade—up 225 percent—is a testament to Canada's open investment climate. US companies in particular play an important role. Collectively oil sands production from US-headquartered firms was 0.4 mbd in 2009, or about 30 percent of the total production. Financial markets are also connected. To date US investors have played a vital role in supplying the capital required for oil sands investments.

Oil sands investments have not only provided returns to investors, but have also created jobs in both the US and Canadian economies. Oil sands investments constitute billions of dollars in spending, and the economic benefits radiate far beyond the borders of Alberta to the rest of Canada and the United States. In the United States new activity arises in many sectors, for example building huge dump trucks and tires, manufacturing massive steel pipes and sophisticated process equipment, and engineering and building both small developments and megaprojects. The Canadian Energy Research Institute (CERI) projected that over the

*Both are members of the North Atlantic Treaty Organization (NATO), and in addition Canada and the United States have jointly run since 1958 the North American Aerospace Defense Command. Canadian armed forces are currently deployed in Afghanistan and have participated with the United States and other NATO forces in this mission since 2001.

next 15 years, in a higher growth scenario (production growth about 10 percent below our high-growth estimate) oil sands activities could add more than 340,000 new jobs to the US economy and contribute over $30 billion annually to the US GDP.*

ENVIRONMENTAL FOOTPRINT ASSOCIATED WITH OIL SANDS DEVELOPMENT

Although oil sands have a larger environmental footprint than many other sources of oil supply, the gap is not always as large as portrayed.

- **GHG emissions.** On a well-to-wheels basis GHG emissions from oil sands are approximately 5 to 15 percent greater than the average crude oil consumed in the United States.** This calculation includes emissions from oil extraction, refining, distribution, and combustion of the refined products. On a well-to-wheels basis the majority of emissions are created when the fuel is combusted in a vehicle. The well–to–retail pump part of the emissions (before combustion of fuel in a vehicle) account for 20 to 30 percent of the total life-cycle GHG emissions. Some analyses have asserted that Canadian oil sands have well–to–retail pump emissions many multiples higher than the average crude oil consumed in the United States. This is not true of the typical or average oil sands development. For example IHS CERA's comparison of 11 publicly available life-cycle analysis studies found that fuel produced from oil sands mining has average well-to–retail pump emissions 1.3 times the average for fuel consumed in the United States. Similarly, fuel produced from oil sands utilizing SAGD has average well–to–retail pump GHG emissions about 1.7 times larger than the average fuel consumed in the United States. Oil sands are not alone; they are part of a group of higher carbon-intensity crudes consumed within the United States, including Venezuelan heavy crude oil; Nigerian crude oils; and crude oils from mature assets that require steam for enhanced oil recovery such as California heavy oil. Also certain fields in the Gulf of Mexico and the Middle East have comparable GHG emissions.

- **Water use.** Most types of energy production use water, including the oil sands. Net water use in oil sands production averages four barrels of water per barrel of bitumen for mining operations and 0.9 barrels of water per barrel of bitumen for in-situ production.*** Conventional oil uses 0.1 to 0.3 barrels of water per barrel of oil produced, while oil produced through enhanced oil recovery can use up to 70 barrels of water per barrel of oil. Oil alternatives can also be water intensive: ethanol from nonirrigated crops is comparable to oil sands mining, and options like coal-to-liquids can use 10 barrels of water per barrel of product. The key factor in water demand for all forms of energy is local availability of water and competition with other water uses. For example for oil sands mining local availability of water is an important issue. Oil

*_The Impacts of the Canadian Oil Sands Development on the US Economy,_ CERI, October 2009.
**The range is based on the average of the life-cycle GHG values reported by 11 publicly available life-cycle studies. In 2009 the Alberta Research Council published two additional studies comparing oil sands GHG emissions to those from other crudes. These studies are not incorporated within this analysis. Inclusion of these new studies and other new research on oil sands GHG emissions are the topic of the next IHS CERA Oil Sands Dialogue report.
***Net mining water use includes water from site runoff and mine dewatering, in addition to water from the Athabasca River. River withdrawals are approximately 2.5 barrels of water per barrel of bitumen.

sands mining operations rely on the Athabasca River for water. The water issues rise and fall with the river itself, for the river is seasonal, with much lower flow in winter than in summer. Thus, water availability is important in the winter when less water is available. The current volume of water allocated to users of the Athabasca is now approaching the winter withdrawal limits. As mined oil sands production increases, more water storage will be needed to reduce the need for additional river withdrawals in the winter months.

- **Land disturbance and reclamation.** About 20 percent of currently recoverable oil sands reserves lie close enough to the surface to be mined. The current footprint of mining operations is about 200 square miles (518 square kilometers), or about 2 percent of the greater Houston, Texas, metropolitan area. Direct land disturbance from mining results in a total loss of the ecological character of the disturbed land during the period of the mining operation. After the mining is complete, operators are required to reclaim the lands. Although reclamation is ongoing, to date the rate of land reclamation has not kept pace with the rate of disturbance. This is largely because of the arc of development of mining operations—it can take many years to finish mining an area so that reclamation can begin. Although slow, land reclamation has been in line with the expectations set forth in the projects' approved reclamation plans.

  About 80 percent of the recoverable oil sands deposits are too deep to be mined and are recovered using in-situ thermal processes. Direct land disturbance from in-situ production disturbs about 2 to 3 percent more land than conventional oil developments.* Like conventional developments, land disturbed by in-situ developments must be returned to its predevelopment state. Although the scale of degradation associated with in-situ development is relatively small compared to mining, fragmentation of the forest decreases the populations of some animal species, which tend to leave an area while human activity occurs.

- **Tailings.** Oil sands mines produce waste material called *tailings*; the waste materials have been difficult to reclaim and have grown larger than projected. In approximately 40 years of commercial oil sands development, the industry has produced nearly 1 billion cubic meters (35 billion cubic feet) of these fluid fine tailings, and the ponds that contain these tailings and other mining waste cover nearly 30 percent of the area currently affected by mining. As the size of the tailing ponds has grown, the public has become more concerned about potential leakage of tailings to the environment and hazards to waterfowl that land on the ponds. To address this issue, in 2009 the Alberta government introduced a new directive enforcing targets for reductions in tailing accumulations. If the goals of this new directive are met, it would reduce the rate at which future tailing accumulations grow.** Although the rate of growth is expected to

*Although a number of developments were considered, IHS CERA estimated the extent of disturbed land using aerial photographs and project approval maps for typical sites: SAGD at Devon Jackfish, conventional oil from the Fletcher Leduc-Woodbend, and conventional gas from EnCana Strathmore. The analysis did not include potential indirect land impacts.

**The directive requires that 50 percent of the clay and silt produced from the oil sands ore after July 2012 be removed from tailings ponds and made solid enough to support heavy equipment traffic. Oil sands operators have submitted plans, and technical solutions to reduce tailings and meet this directive are still being developed.

slow, overall volumes of tailings are still projected to grow with production growth from new mining operations.

- **Regulatory landscape.** Oil sands are a highly regulated industry. At a project level government regulation of oil sands activities is as robust, if not more so, than in many other oil-producing regions in the world. However, given the scale of current and potential future activity, the total impact of all of the cumulative development on the region's air, water, land, and biodiversity needs to be considered. To address this, in 2008 the Alberta government introduced the Land Use Framework, which aims to impose regional limits for air, water, and land use.*

- **Limits to growth.** If growth from current production levels were to reach the 2030 high growth projection (5.7 mbd), a number of growth limits must be addressed. Examples include these issues: water management practices must advance to minimize consumption of fresh water from the Athabasca River during winter months, the pace and scale of tailings management and site reclamation must increase, and local infrastructure must be developed in a timely manner. The high growth case requires a doubling in the rate of annual new productive capacity growth; therefore project execution must speed up to meet this growth projection.

CONCLUSION

In September 2009 US Secretary of Energy Stephen Chu requested a National Petroleum Counsel study on the topic of "The Prudent Development of North America's Natural Gas and Oil Resources." The scope of the study considers the possible size of energy reserves and future productive capacity in a North American context, highlighting how oil sands as well as other sources of North American supply are being considered within US energy policy. Not only are North American energy sources being considered uniquely, but possibly so too are the environmental implications. In early 2009 Canada and the United States announced the "Clean Energy Dialogue." The Dialogue signals the potential for increased levels of collaboration between the two nations, working jointly to find solutions to environmental challenges while securing the energy required for future growth.

Energy security needs do not have to be at odds with the environment. Innovation in oil sands has been a constant theme. As in the past, ongoing investment in research, advancements in new extraction techniques, and improvements to existing methods should be expected. Both the US and Canadian governments, in collaboration with the industry, can play an important role in developing new technologies. Government support is important in providing funding to accelerate the development of new technologies. As production levels increase, new technologies are needed to reduce GHG emissions, water and energy use, and the scale of land disturbance and to increase the pace of land and tailing pond reclamation. A collaborative approach among all stakeholders will enable the full potential of this world-

*The Alberta Land Use Framework is developing regional plans defining economic, environmental, and social outcomes from development; it will integrate provincial policies and provide the context for land-use decisions at the regional level. A cumulative effects management approach will be used to manage the combined impacts of existing and new activities within each region of the province.

class resource to be realized in a sustainable manner, a resource that is just next door from the United States—the world's biggest oil consumer.

REPORT PARTICIPANTS AND REVIEWERS

IHS CERA hosted a focus group meeting in Calgary on February 4, 2010, providing an opportunity for oil sands stakeholders to discuss perspectives on the key issues related to the role of oil sands in US energy supply. Additionally a number of participants reviewed a draft version of this report. Participation in the focus group or review of the draft report does not reflect endorsement of the content of this report. IHS CERA is exclusively responsible for the content of this report.

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IHS CERA TEAM

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Samantha Gross, IHS CERA Director, specializes in helping energy companies navigate the complex landscape of governments, nongovernmental organizations, shareholders, and other stakeholders when making investment decisions. She led the environmental and social aspects of CERA's recent study *Growth in the Canadian Oil Sands: Finding the New Balance*, including consideration of water use and quality, local community impacts, and aboriginal issues. Ms. Gross was also the IHS CERA project manager for *Thirsty Energy: Water and Energy in the 21st Century*, produced in conjunction with the World Economic Forum. Additional contributions to IHS CERA research include reports on the water impacts of unconventional gas production, international climate change negotiations, US vehicle fuel efficiency regulations, and the increasing demands placed on international oil companies by governments in resource-rich countries. Before joining IHS CERA she was a Senior Analyst with the Government Accountability Office, where she managed a study of the role and capability of the US Strategic Petroleum Reserve, led an analysis of US refining capacity and inventory practices, and prepared congressional testimony on electricity risk management practices, among other energy projects. Her professional experience also includes providing engineering solutions to the environmental challenges faced by petroleum refineries and other clients. Ms. Gross holds a BS from the University of Illinois, an MS from Stanford University, and an MBA from the University of California at Berkeley.

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