Canadian Oil Sands Face US GHG Policy Uncertainty

SPECIAL REPORT

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About This Report

Purpose. This IHS CERA Special Report offers an independent assessment of the potential impact of evolving US greenhouse gas (GHG) policy on crude oil markets, particularly the Canadian oil sands. The outcome of the policy debate will help to shape the economic and political playing field for the oil sands industry and could have a broader impact on oil supply and energy security in the United States and beyond.

Context. This is the final in a series of reports from the IHS CERA Canadian Oil Sands Energy Dialogue 2010. The dialogue convenes stakeholders in the oil sands to participate in an objective 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
- Oil Sands, GHG, and US Oil Supply: Getting the Numbers Right
- Oil Sands Technology: Past, Present, Future
- Canadian Oil Sands Face US GHG Policy Uncertainty

These reports and IHS CERA's 2009 Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance* can be downloaded at www2.cera.com\oilsandsdialogue.

Methodology. This report includes multistakeholder input from a focus group meeting held in Washington, DC, on November 18, 2010, and participant feedback on a draft version of the report. IHS CERA also conducted its own extensive research and analysis both 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 end of report for a list of participants and the IHS CERA team).

Structure. Following the Summary of Key Insights, this report has three major sections:

Part I: Introduction. What US policies—both existing and possibly forthcoming—could reduce GHG emissions from transport? What do Canadian oil sands have to do with US GHG policy?

Part II: Reducing US GHG Emissions. What is the status of each policy? How could each bring about a reduction in GHG emissions? What are the challenges and potential implications of each?

Part III: Conclusion. How much could each policy, or a combination of these policies, reduce GHG emissions and consequently oil demand? How would oil from the oil sands, in particular, be affected by such a policy or policies?

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.

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CANADIAN OIL SANDS FACE US GHG POLICY UNCERTAINTY

SUMMARY OF KEY INSIGHTS OF IHS CERA'S ANALYSIS

Policies are being developed and implemented in the United States that aim to reduce greenhouse gas (GHG) emissions from the transportation sector—the source of one third of US emissions. The future course of US GHG policy can influence crude oil demand, supply, and cost. Consequently the outcome of the policy debate will also shape the development of the oil sands—perhaps even more so than other sources of oil supply.

Policies that aim to reduce transportation GHG emissions vary in their potential to reduce GHG emissions and oil demand. They also vary in the likelihood that they will be implemented as planned. A patchwork of regional and national GHG rules is in development; yet many policies are expected to fall short of their initial targets. Only the federal vehicle fuel economy rules specifically target emissions from vehicle tailpipes—the source of 70 to 80 percent of the emissions from transportation fuels. At present this initiative has the highest potential impact on US GHG emissions and oil demand.

GHG policies have the potential to accelerate the long-term trend of flat to slightly declining US petroleum-based liquid fuel demand. At the same time supply from the Canadian oil sands is increasing and will likely double in the next decade. By 2030, in IHS CERA's expected policy case, US petroleum demand is slightly below 18 million barrels per day (mbd) (not including biofuels), compared with 18 mbd in 2010. In our stretch case policies overcome implementation hurdles and achieve difficult mandates, and petroleum-only demand drops to 16 mbd by 2030. Either way the United States remains one of the world's top crude oil destinations—a market large enough to absorb all oil sands growth.

Some US GHG policies, if adopted on a nationwide scale or by states, could disproportionately raise the cost of oil sands development and lower its competitiveness compared to other oil supply options. Uncertainty about the final effects of US GHG policies is already adding risk to billions of dollars in oil sands investments. One such policy is California's Low Carbon Fuel Standard (LCFS), which would require fuel suppliers to use a greater amount of low-carbon alternative fuels (such as biofuels, electricity, or natural gas) to offset the higher carbon-intensity of oil sands crudes. Also cap-and-trade or other carbon price mechanisms have the potential to disproportionately affect oil sands; if US policy does not account for carbon costs already incurred in other jurisdictions, the same carbon emissions could be paid for multiple times—penalizing jurisdictions (such as Canada) that have carbon policies and rewarding those that do not.

PART I: INTRODUCTION

BET BIG OR WAIT FOR ANSWERS? WHAT UNCERTAIN US GREENHOUSE GAS POLICIES MAY MEAN FOR THE CANADIAN OIL SANDS

A multibillion-dollar investment decision is not taken lightly. Large capital investments in any industry are made in the face of risks, and the energy industry is certainly no exception. Indeed a volatile oil price that has swung from around $10 to more than $140 per barrel in the past dozen years illustrates one high-profile risk. There are, of course, others. Will demand and supply patterns change abruptly, as they have in the past? Will new technology or competitors alter the playing field? Energy companies have operated in this environment for many decades and know it well. But today there is a complex and increasingly perplexing factor, and the outcome will affect not only energy companies, but also consumers and governments: the future course of US GHG policy.

The matter of GHG emissions is not new. For years it has been a part of the policy debate at many levels of government. And investment decisions have long been influenced by the multiple societal dimensions of energy use, including environmental effects, fueling economic growth, and energy security concerns. Finding the right balance remains a critical path for investment decisions. So the matter of GHG limits—and of environmental quality overall—did not materialize overnight. But what makes today's investment and regulatory environment increasingly fraught with risk is the patchwork of regional and national GHG policies combined with questions concerning their political durability. What if billions of dollars are invested based on a particular policy outcome, but then that policy is materially affected after the next election cycle or by a different government jurisdiction? The uncertain path of GHG policy is a political risk in North America for energy companies.

What do Canadian oil sands have to do with US GHG policy? The Canadian oil sands are one of the most important energy investment destinations in the world. Growth in oil sands production has made Canada by far the largest source of oil imported into the United States. In the first three quarters of 2010 total Canadian oil imports (oil sands, conventional oil, and refined products) averaged 2.5 mbd—nearly double that the number two supplier, Mexico.[1] Canadian oil sands are also energy intensive. Life-cycle GHG emissions from fuels derived wholly from oil sands range from 5 to 15 percent higher than the average crude processed in the United States.[2] The oil sands are not alone in this regard. Some crude oil from Venezuela, Nigeria, and some US domestic crudes are in the same range. However, the oil sands' proximity to the United States, the relative accessibility of oil sands data and operations, and expectations of ongoing supply growth generate a higher profile in the environmental arena than many other sources of supply. The United States is, for now, virtually the only market for Canadian oil sands, so US GHG policy, including that of

1. US crude oil imports include Canadian conventional supply estimated at 0.9 mbd, oil sands supply near 1.1 mbd, and refined products of 0.5 mbd.
2. Life-cycle emissions are calculated on a well-to-wheels basis (including emission from fuel combustion in the vehicle). Most GHG emissions are related to combustion—the gasoline being consumed in an engine. The amount of energy used to extract, process, and refine oil sands—the well-to–retail pump portion of life-cycle emissions—results in GHG emissions that are 1.3 to 1.6 times higher than the average crude refined in the United States. Source: IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right*.

Note: Prices are in US dollars unless otherwise indicated.

individual states, will shape the future role of the oil sands in the fabric of North American energy security, economic growth, and environmental outcomes.[1]

PERPETUAL POLICY MOTION?

The potential impact of US GHG policy is profound across a range of economic, security, and environmental dimensions. The impact is not just simply related to the implications of a particular policy being implemented or proposed. The mix and uncertain durability of measures across a range of jurisdictions are creating additional layers of risk. It this state of potential "perpetual policy motion" that could conceivably be as harmful to interests across the political and environmental spectrum as any specific but enduring policy measure.

NO GREEN OR RED LIGHT, BUT YELLOW

Momentum toward or away from a national US GHG policy has been buffeted by changing political winds. At times in recent years it appeared that momentum was building toward greater clarity in US GHG policies. But this momentum dissipated as the Great Recession and stubbornly high unemployment led to a shift in priorities, at least in the national legislative arena. At the same time measures in other branches and levels of government have been implemented or are progressing toward consideration or adoption. Yet even in some of these cases, there is no certainty that the measures will be likely to endure election cycles. The net effect is neither a red nor a green light toward a clear and widely supported GHG policy in the United States—just a bright yellow light of caution.

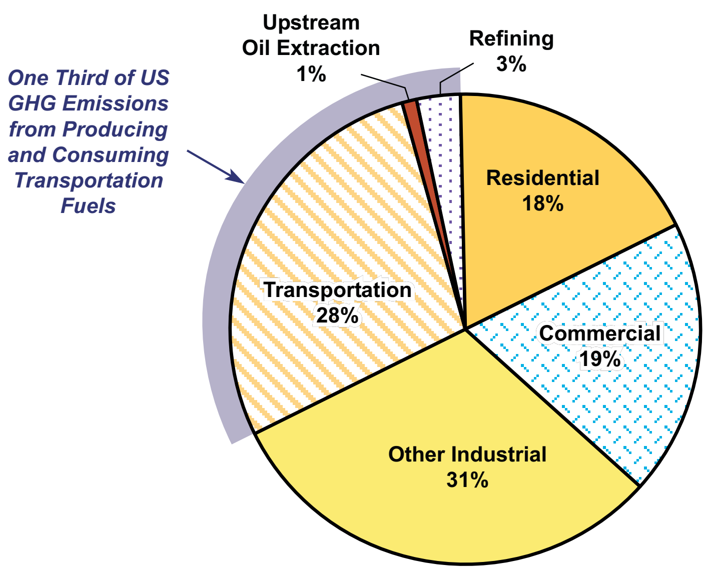
CONNECTIONS: GHG EMISSIONS, ENERGY USE, TRANSPORTATION, OIL, AND THE OIL SANDS

GHG policies are inextricably linked to energy use. Producing and refining oil accounts for about 5 percent of US GHG emissions, while fueling the cars, trucks, planes, and trains to transport people and goods represents 28 percent of total US GHG emissions (see Figure 1). Since petroleum constitutes 95 percent of US transportation energy, the future course of GHG policy could shape the future course of oil demand, supply, and cost.[2] Consequently, this will also shape the oil sands—perhaps even more so than other sources of oil supply.[3] Although the political debate about oil sands in the United States has tended in recent years to focus more on carbon, greater uncertainty in the Middle East is likely to elevate energy security as a concern and thus the importance of oil sands as a large-scale, growing, secure North American resource.

1. In the first three quarters of 2010, less than 2 percent of oil sands production was exported to non-US destinations. Source: NEB.
2. The nonpetroleum part is from biofuels.
3. This is due to the higher carbon intensity of oil sands and its sole dependence on the US market.

Figure 1

Breakdown of US GHG Emissions



Source: EIA and IHS CERA (estimated upstream and refining).
10207-1

REPORT STRUCTURE

Part II of this report explores a number of US policies, in various stages of implementation, all targeting reductions in US GHG emissions from transport. Many of these policies are still uncertain, and some are not likely to be implemented in their current form—or perhaps not at all. This report serves as a framework for understanding the current GHG policy playing field and assesses the potential implications for the oil sands industry, including repercussions on energy security, the economy, and environmental outcomes.

PART II: REDUCING US TRANSPORT EMISSIONS

A number of policies being considered or implemented could affect GHG emissions from transport and consequently influence oil demand. The four main policy areas are[1]

- Policy Area One: US Environmental Protection Agency Regulations.
- Policy Area Two: Renewable Fuel Standard. This is a US federal mandate requiring the US transportation sector to use a minimum volume of biofuels.
- Policy Area Three: Carbon price. These include cap-and-trade schemes or a carbon tax. Such programs are designed to reduce GHG emissions by attributing an economic cost to emitting carbon dioxide (CO_2).
- Policy Area Four: Low Carbon Fuel Standards. The goal of LCFS is to displace petroleum in the transportation sector with alternative fuels that have lower GHG emissions.

In Part II we describe these policy areas and assess of their potential impact on transport and oil.

POLICY AREA ONE: US ENVIRONMENTAL PROTECTION AGENCY REGULATIONS

In addition to regulating conventional pollutants (including pollutants responsible for acid rain and ozone depletion), the US Environmental Protection Agency (EPA) has begun to regulate GHG emissions through the Clean Air Act. Movement toward regulation began in 2007, when the US Supreme Court upheld EPA's authority to regulate GHG emissions under the existing Clean Air Act, which was originally enacted to control air pollution. In 2010, EPA outlined two paths for regulating GHG emissions: the first to reduce GHG emissions from large stationary sources (such as power plants and refineries); and the second to reduce GHG emissions from mobile sources, specifically light- and heavy-duty vehicles. The latter regulations have taken the form of higher fuel economy standards for vehicles.

EPA's role in reducing GHG emissions has been controversial. Some members of US Congress are moving forward with initiatives to stop or slow EPA's regulation of GHGs, arguing that these regulations could harm the economy and are outside the agency's remit. In addition some states have initiated legal challenges, questioning EPA's authority in this regard.

EPA: Stationary Source Regulations and GHG Reductions

New EPA regulations for stationary sources came into effect on January 2, 2011. For now, the stationary source rules target large, concentrated, industrial emissions sources. The sources relevant to the transportation sector, oil refineries, are responsible for 3 percent of all GHG emissions in the United States. The new regulations stipulate that any refinery that is newly built or that undergoes major modifications must deploy the best available control

1. Policy areas are numbered for ease of reference and to facilitate the reading of this report. They are not intended as a ranking of any sort.

technology (BACT) to reduce GHG emissions. BACT, however, is a concept that is open to interpretation. Currently the EPA interprets BACT as technology that improves energy efficiency (thus lowering GHG emissions). In the future BACT could include currently high-cost technologies, such as carbon capture and storage (CCS), as such technologies mature and costs come down. The definition of BACT is likely to evolve slowly.

In addition to existing BACT regulations, EPA kicked off a new round of GHG regulations in December 2010. Under a settlement agreement with several environmental nongovernmental organizations and state governments, EPA agreed to develop new source performance standards (NSPS) for both power plants and refineries. For refineries we expect that final NSPS rules will not be adopted until after 2012. Despite the name, NSPS would apply to both new and existing sources, and unlike BACT requirements, NSPS could be applied independently of whether a plant is undergoing major modification. EPA has yet to release a draft rule for NSPS, and a wide range of outcomes is possible. For example EPA could use NSPS to set output-based performance standards, e.g., GHG per unit of output, and some have even suggested this provision could be used to develop limited regional cap-and-trade programs. Although it is too early to know for certain, NSPS requirements could ultimately prove more challenging than the current BACT requirements for GHG emissions.

Limited Emission Reductions from Refinery Efficiency Alone

For oil refiners it makes economic sense to reduce energy consumption, since energy is a key input cost. This in turn reduces GHG emissions—a win-win scenario. Over the past 18 years, on average the energy required to refine a barrel of crude oil by US refineries has declined 8 percent. Still, for the most sophisticated and large refineries, greater efficiency improvements could be possible. Some of the world's most advanced refineries have targeted energy efficiency improvements of around 10 percent per decade. Considering this, refiners could potentially reduce their energy consumption (and hence GHG emissions) between 4 to 10 percent (assuming plantwide improvements). But this would be a best-case, maximum efficiency improvement scenario. If this best-case scenario could be achieved, it would reduce GHG emissions by about 19 million metric tons (mt) of carbon dioxide equivalent (CO_2e) per year from the refining sector—roughly equivalent to the annual emissions of four to five average-size coal plants.[1]

Challenges in Implementation: Applying BACT

The Clean Air Act is not new—it was signed in 1970 and has been used to regulate pollutants such as particulate matter, carbon monoxide, and sulfur dioxide. What is new is applying the act to the regulation of GHG emissions. Apart from legislative and legal challenges, the most significant implementation hurdle is an uncertain interpretation of BACT (along with EPA's determination on NSPS). In EPA's regulation of other pollutants, what constitutes BACT has varied from state to state and from project to project. This does not mean that the rule cannot be enforced; the Clean Air Act has used BACT for decades. But it does suggest that

1. All coal plant–equivalent emissions calculations in this report are based on the EPA Calculator (http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results). The calculator assumes in 2005 there were 1,973,625,358 tons of CO_2 emitted from power plants whose primary source of fuel was coal. In 2005 a total of 465 power plants used coal to generate at least 95 percent of their electricity.

implementation of BACT for GHG emissions will likely be uneven. It also suggests that the extent of potential GHG reductions will be much smaller than the industrywide, best-case, maximum efficiency improvement scenario above.

Implications for Oil and the Oil Sands: A Possible Disadvantage

Assuming that EPA's BACT guidelines for refiners continue to focus on energy efficiency improvements, crude oil with higher-than-average GHG life-cycle emissions, such as from the Canadian oil sands, should not be at a significant disadvantage to other crudes. Although the rule is expected to increase costs for refiners, it is not expected to have a significant effect on oil demand. The mandate addresses efficiency improvements for producing fuels, not consuming them.

Depending on the final definition of NSPS as a performance standard, specific implications for higher carbon crudes are possible. For example, if the performance standard becomes GHG per barrel of refined product, and refining oil sands crudes result in higher emission intensities, there could be an incentive to avoid these crudes.

EPA: Mobile Source Transportation Emission Regulations and GHG Reductions

EPA aims to reduce GHG emissions from light-duty motor vehicles and medium- and heavy-duty trucks. In April 2010, EPA and Department of Transportation (DOT) finalized the Corporate Average Fuel Economy (CAFE) standards for light-duty vehicles.[1] The rules stipulate all new light-duty vehicles must average 35 miles per gallon (mpg) by 2016—nearly a 30 percent improvement over today's average efficiency standard of about 27.5 mpg for new cars and trucks. The EPA and DOT are considering more stringent CAFE standards by 2025—potentially between 47 and 62 mpg.

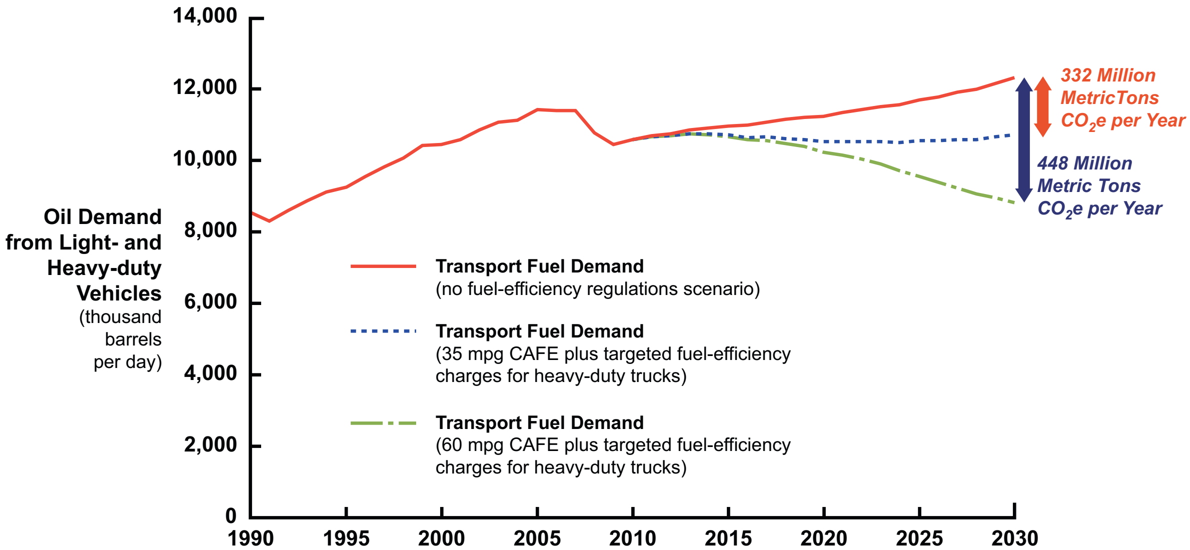
For medium-duty and heavy-duty trucks—including everything from large pickup trucks and vans to long-distance buses and semi-haulers—EPA and DOT are developing fuel-efficiency standards for the first time. These rules are planned to start in 2014 with full implementation by 2018. The new fuel efficiency standards are expected to be finalized by August 2011, and improvements as high as 25 percent for some vehicle classes are being targeted.

Since 70 to 80 percent of well-to-wheels emissions from producing and consuming transportation fuels comes from consuming fuel in the vehicle, regulations targeting fuel economy (how far a vehicle can travel on a given amount of fuel) can significantly decrease GHG emissions from transportation. Under the current rules (35 mpg for new light-duty vehicles and targeted fuel efficiency changes for heavy-duty trucks), GHG emissions would decline 332 mt CO_2e per year by 2030 compared with a scenario with no fuel efficiency changes. These reductions are equivalent to the annual emissions of 86 coal plants. In the stretch case GHG emissions decline 448 mt CO_2e per year by 2030—equivalent to the annual emissions of 116 coal plants (see Figure 2).[2]

1. The standards are set by EPA and the National Highway Traffic Safety Administration (NHTSA), which is a division of DOT.
2. EPA's stretch case, or higher-end proposal, is assumed to be 60 mpg by 2025 for light-duty vehicles and targeted fuel efficiency changes for heavy-duty trucks.

Figure 2

EPA Mobile Source Transportation Emissions: Effect on Oil Demand and GHG Emissions per Year



Source: Historical data from EIA, projections from IHS CERA.
10207-3

Challenges in Implementation: Vehicle Technology Development Required to Meet Targets

The light-duty regulations for 2016 and beyond are likely to require deployment of new technologies by automakers. By contrast the medium- and heavy-duty truck fuel economy proposal aims to leverage existing technology to improve fuel efficiency.

Automakers can comply with light-duty CAFE standards in a number of ways. Likely options will include a mix of the following actions:

- producing electric vehicles (EVs)
- dramatically improving efficiency of combustion engines
- producing smaller and lighter vehicles

The pace of development of new, potentially more expensive technologies along with changes in consumers' preferences will be critical in defining the future vehicle mix.

In 2010 virtually all US light-duty vehicles were based on combustion engine technology. In 2011 for first time commercial numbers of battery electric vehicles (BEVs) or plug-in hybrid electric vehicles (PHEVs) are being offered by major auto manufactures in the United

States.[1] Sales of BEVs and PHEVs in 2011 are expected to be around 18,000 vehicles in the United States—still a small percentage of close to 13 million light-duty vehicles projected to be sold in 2011 or the over 250 million already on the road.

Assuming the introduction of a high CAFE target for 2025 (60 mpg or higher), alternative vehicle technologies must advance quickly; the costs have to come down, or it will be difficult to entice consumers to purchase these more expensive vehicles. Because of the significant hurdles to meeting the 2025 stretch case goal (above 60 mpg), we expect that EPA and DOT will issue a lower 2025 target. A decision is likely in the next year or two. Congressional opposition is another potential headwind against an aggressive 2025 target. Considering the potential magnitude of the 2025 targets, it's possible that legislators would try to reduce the level or block altogether the adoption of a stringent target.

Implications for Oil and the Oil Sands: Same for All Crudes

EPA's current 35 mpg light-duty and targeted heavy-duty regulations will reduce US oil demand by more than 1.6 mbd by 2030 compared with a scenario with no fuel economy change.[2] In a stretch case, where light-duty vehicles reach 60 mpg by 2025 and targeted heavy-duty regulations are in force, US oil demand would be 3.5 mbd lower by 2030. Comparing the heavy-duty and light-duty efficiency gains, the light duty is responsible for the majority of the oil demand decline—about 80 percent. Like the EPA stationary source regulations, however, this ruling will affect all crude sources equally and therefore should not result in significant disadvantages for higher-carbon crude sources, such as the Canadian oil sands.

POLICY AREA TWO: RENEWABLE FUEL STANDARD

Policy and GHG Reductions under the US Federal Mandate

The RFS2 is a US federal mandate requiring the US transportation sector to use a minimum volume of biofuels each year to 2022. One of the aims of this policy, in addition to reducing dependence on foreign oil and boosting the domestic renewable fuels sector, is to decrease GHG emissions by substituting petroleum with lower-carbon biofuels. Under the current rules 2.35 mbd of biofuels must be consumed by 2022. The program was established in 2005 as RFS and updated with higher targets in 2007, which has become known as RFS2. RFS2 also introduced specific categories of renewable fuels (renewable fuel, advanced biofuel, cellulosic biofuel, and biomass diesel), setting volume and GHG emission targets for each type. To count as a renewable fuel under RFS2, the well-to-wheels GHG emissions of the biofuel must be less than the petroleum it is replacing, by a specific threshold.[3] Although

1. 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. PHEVs do not include "conventional" hybrids, such as the Toyota Prius, which is classified as a combustion engine vehicle—albeit a higher-efficiency one. BEVs are all-electric vehicles.
2. This scenario assumes that vehicle economy is the only static variable; other factors including vehicle miles driven and total number of vehicles still continue to grow.
3. For instance EPA stipulates that total emissions for corn-based ethanol (produced from newly constructed biorefineries) must be 20 percent lower than that of petroleum gasoline. Other biofuels must achieve even higher targets: cellulosic ethanol must have 60 percent lower GHG emissions than petroleum gasoline.

the program calls for biofuels in general, the vast majority of the biofuels consumed in the United States is ethanol, a substitute for gasoline.

The EPA anticipates that even without the RFS2, the United States would consume 0.9 mbd of biofuels by 2022. Consequently if the RPS2 rule is achieved, it would result in 1.45 mbd of additional biofuel consumption compared with a "no policy" case.[1] EPA estimates that by 2022 GHG emissions will be 138 mt per year lower than without the policy—or equal to the annual emissions of 32 coal-fired power plants. Assuming that the additional biofuels are from conventional ethanol (which has about one-third lower energy content than the same volume of petroleum fuel), this would mean about 1 mbd of lost petroleum-based oil demand.[2]

However, given the challenges in supplying and consuming large volumes of biofuels (see Challenges in Implementation, below), IHS CERA expects that US biofuel consumption will fall well short of the 2022 RFS2 mandate—hitting just 1.3 mbd by 2022. Taking into account EPA's projection for biofuels consumption with no mandate, the policy results in only 0.4 mbd of additional biofuel consumption by 2022 (over the "no policy" case). Thus we estimate RFS2 will reduce GHG emissions by 20 mt per year—equal to the annual emissions of about 5 coal-fired power plants.[3]

Challenges in Implementation

Both the suppliers and consumers of biofuels will face challenges in complying with RFS2.

Supply Challenges May Change Timeline

Of the 2.35 mbd of biofuels mandated by 2022, the majority will be from ethanol. The volume of ethanol derived from corn starch—the only commercially viable biofuel in the United States today (with the exception of relatively modest volumes of biodiesel)—is capped near 1 mbd. The remainder, 1.37 mbd, must be from "advanced biofuels" derived from noncorn feedstocks. Of this noncorn portion about 0.33 mbd can be "undifferentiated" advanced biofuels, for example biodiesel or sugarcane-based ethanol (likely sourced from Brazil). The rest, 1 mbd, must be derived from cellulosic feedstock (such as switchgrass, corn stover, or wood chips). Yet cellulosic biofuels are not close to being produced at a commercial scale.[4] Without rapid development and scale-up of cellulosic production, the United States will fall short of the 2022 targets.

1. The biofuels projection (in the absence of RFS2) is based on the Energy Information Administration's (EIA) 2007 Annual Energy Outlook (AEO)—a forecast created prior to the enactment of EPA's policy. Source: EPA Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis, February 2010.
2. Owing to the lower energy content, the volume of oil displaced is less than the biofuel volume.
3. IHS CERA assumes that less than 5 percent of 2022 ethanol volume is from the lowest-carbon ethanol—cellulosic. The majority of the ethanol is assumed to be corn based. Most ethanol derived from corn has a 20 percent GHG benefit compared with petroleum gasoline. The lack of very low-carbon ethanol, along with less volume overall, notably reduces GHG emission benefits.
4. Currently no commercial-scale cellulosic biofuels are being produced. Challenges to commercial production include process economics, feedstock availability at large scale, and feedstock and fuel transporting logistics.

Consumption Challenges with Consumers

Even if the supply challenges are overcome, it will be a test whether consumers can utilize the ever-higher mandated volumes of ethanol. Although a portion of the ethanol could be seamlessly blended into conventional gasoline (either as 10 or 15 percent ethanol blends with gasoline), given ethanol's corrosive properties a significant volume—more than 1 mbd—would have to be consumed in flex-fuel vehicles (FFVs) that can handle the more corrosive, higher-ethanol blends such as E85 (85 percent ethanol and 15 percent gasoline).[1] Both the sales of FFVs and the development of the infrastructure to distribute the E85 fuel would have to accelerate dramatically. Specifically fueling stations would have to install new tanks and pumps, and consumers would have to buy more FFVs. Even if these logistical hurdles could be overcome, consumers would still have to choose to fill up with E85. Given that E85 has about 25 percent less energy than an E10 blend (and therefore will require more frequent refueling) consumers may balk at purchasing E85 unless it is substantially discounted.

Implications for Oil and the Oil Sands: No Specific Impact

Given IHS CERA's expectation that biofuel consumption will fall short of EPA's target for 2022—and taking into account the lower energy yield of ethanol compared to gasoline—we expect the RFS2 to lead to a reduction in US petroleum-based oil demand of only 0.3 mbd by 2022 (taking into account EPA's forecast of 0.9 mbd of biofuels consumption by 2022 without the mandate). This is a much more modest amount than the 1 mbd of lost petroleum-based oil demand that results if the mandate's target is achieved. This policy has no specific impact on oil sands.

POLICY AREA THREE: CARBON PRICE

Carbon Price Policy and GHG Reductions

Carbon price policies, such as cap-and-trade or carbon tax, are designed to reduce GHG emissions by using market forces—imposing an economic cost for emitting carbon and thus providing carbon emitters an incentive to reduce GHG emissions. A carbon tax requires emitters to pay the government, not unlike a sales tax on goods and services. The cap-and-trade mechanism establishes a maximum limit—or cap—on the amount of emissions that various entities can emit. Entities that emit less than their maximum limit are able to sell or trade their surplus allowance in the form of a carbon credit. A key difference between a carbon tax and cap-and-trade is that the price of carbon under a carbon tax policy is fixed, whereas the price of carbon in a cap-and-trade policy is determined by supply and demand, and thus fluctuates.

1. On October 13, 2010, EPA granted a waiver of the 1990 Clean Air Act, allowing gasoline retailers to sell a fuel mixture that is 15 percent ethanol and 85 percent gasoline by volume (E15), a change from the current maximum of 10 percent ethanol (E10). However, the decision approved E15 only for use in model year 2001 and newer cars and light trucks. It will likely take several years before E15 can be widely commercialized since one third of the US on-road vehicle fleet today was built before 2001.

Outlook for a Federal US Carbon Price Policy in the Near Term Has Dimmed Significantly

From 2009 until the first half of 2010, there were credible prospects for a federal cap-and-trade policy. In June 2009 the House of Representatives passed the Waxman-Markey bill, the centerpiece of which was an economywide cap-and-trade program. But this type of policy never gained serious momentum in the Senate. Many senators were concerned over the cost of such policies and were wary of new legislation that would potentially dampen economic growth. Despite such concerns, some proposals were discussed in the Senate during the previous Congressional Sessions (2009–10), including one that called for a cap-and-trade program that would be limited, at least at first, to the electric utilities sector.[1]

However, prospects for a federal cap-and-trade policy—either economywide or targeting specific industries—have dimmed significantly, and this option now seems unlikely during the current decade. Nonetheless several states have taken it upon themselves to establish a cap-and-trade system. Ten Northeast states—including New York, New Jersey, and Massachusetts—in 2009 set up the Regional Greenhouse Gas Initiative (RGGI), a cap-and-trade system for the utility sector. A group of seven US states and four Canadian provinces, working under the umbrella of the Western Climate Initiative (WCI), is developing another regional cap-and-trade system. Although WCI is still moving forward, for some jurisdictions participation is becoming more uncertain.[2] In February 2011 the Midwestern Governors Association (representing 10 states) announced that it is abandoning its 2007 cap-and-trade plan; the states are now focused on “encouraging investment of all kinds, and job generation.” Meanwhile California has developed a cap-and-trade program that starts in 2012; transport emissions are added to the program by 2015.

Limited GHG Emission Reductions Expected for Transport Sector

Regarding the use of petroleum-based fuels, a high carbon price is required to change consumer behavior. A $20 per metric ton cost applied across well-to-wheels emissions (from fuel production through to consumption) means a $0.30 per US gallon—or approximate 10 percent—increase from late 2010 prices. Such a modest increase is unlikely to significantly change consumer behavior. We expect that a carbon price in excess of $100 per metric ton is required to incentivize a change in driving patterns and consumer vehicle preferences. However, implementing carbon prices in this range is likely to create political issues for any government; higher energy costs in turn hurt the consumer and voter. For emissions that result from the production of transportation fuels (i.e., oil extraction or refining), a lower carbon price (such as $20 to $30 per metric ton) would incentivize some efficiency improvements, but CCS systems would be needed to bring about larger GHG reductions. As CCS is still a relatively immature technology, a high carbon price (likely in excess of $50 per metric ton) would be necessary to incentivize refiners to consider installing CCS. For

1. Senators John Kerry (D-MA) and Joe Lieberman (I-CT) proposed a “utility first” cap-and-trade program in mid-2010, but they never released the full text of a bill associated with such a proposal.
2. WCI includes Washington, Oregon, California, Arizona, New Mexico, Utah, Montana, British Columbia, Manitoba, Ontario, and Quebec. Thus far only some of these states and provinces have passed the legislation required for the originally planned 2012 start. Recently Arizona and Utah have indicated their intent not to participate in the cap-and-trade element of the WCI. New Mexico’s new governor has stated her opposition to a cap-and-trade. In British Columbia the premier supporting the original plan recently resigned.

upstream oil production emissions (which are mostly low pressure, distributed, and dilute) the costs are much higher.

If a US federal carbon price policy were to emerge, what range of carbon costs would be likely? Regulations elsewhere provide indications of the potential price levels. In Europe (with a cap-and-trade program for large emitters since 2005) carbon recently traded between \$15 and \$20 per metric ton. In the province of Alberta, which sets carbon intensity limits for large emitters, a fixed cost of C\$15 per metric ton is charged for CO_2 emissions beyond the limit.[1] For RGGI in the Northeast carbon prices have been about \$2 per metric ton, and in California (which has a cap-and-trade program scheduled to start in 2012) there is a price floor of \$10 per metric ton starting in 2012, with controls that try to limit prices below \$40 per metric ton. At these price levels we expect only small GHG reductions by producers and consumers of transportation fuels.

Challenges in Implementation: Domestic versus Imported Products

Since petroleum fuel is produced in a multistep process—often spanning multiple jurisdictions (countries, states, and provinces)—implementing a carbon price policy has challenges. A critical question is how to account for the out-of-country GHG emissions and policies. For instance for US crude oil imports, emissions from the production process occur in the country of origin, whereas refining emissions occur in the United States. For US refined products imports both production and refining emissions occur outside of the United States—sometimes in multiple countries.

There are two main approaches to account for out-of-country GHG emissions: a “reach back” type policy that accounts for all emissions (including emissions that occur outside of the country) or a policy that applies a carbon price only to GHG emissions originating in the country. The first approach is the most likely to be enacted because it ensures that the domestic petroleum industry is on a level playing field with competitors. If emissions outside the country are not accounted for, there would be an economic incentive to move carbon-intense industrial activities to locations where no carbon price is levied (often termed *carbon leakage*).

Charging the Same Carbon Molecule Multiple Times?

One of key challenges of implementing a “reach back” type policy is to fairly account for out-of-country emissions. Even if exporting countries provide the data to the US government, data quality and transparency is certain to be an issue. Another challenge is how to account for products that come from jurisdictions with existing in-country carbon-price policies. If the imported products have already incurred a carbon cost in their home country, the US “reach back” policy could effectively be charging the same carbon molecule again—penalizing jurisdictions with an in-country carbon policy and rewarding those that do not.

1. The province of Alberta’s Specified Gas Emitters Regulation sets an intensity-based performance standard for all facilities emitting more than 100,000 mt of GHG emissions. Regulated facilities are required to reduce their emissions intensity by 12 percent below a 2003–05 baseline. Facilities with emissions that exceed the intensity target can comply by purchasing credits from facilities that are under the standard emissions baseline, purchasing Alberta-based GHG offsets, or paying a C\$15 fee for emissions over the target. The money collected from the fee supports a technology fund for clean energy research; to date more than C\$187 million has been collected.

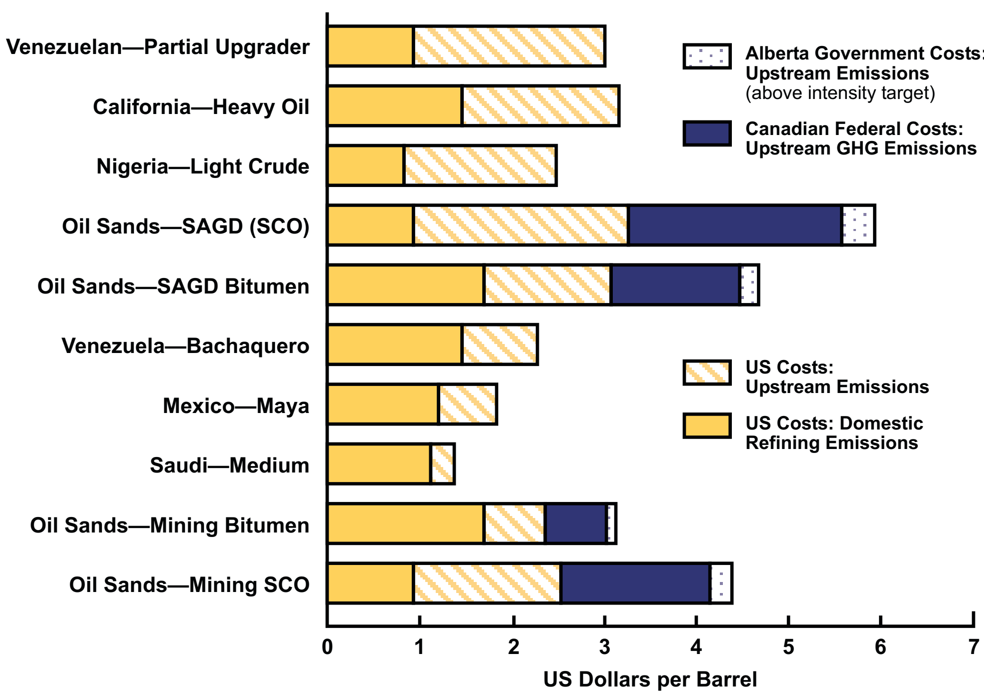
Implications for Oil and the Oil Sands: Policy Face-off

Although a US federal carbon price policy appears less likely than would have been the case a few years ago, oil sands investments have a long time horizon—in many cases more than 40 years. Therefore during the life of an oil sands investment US adoption of a carbon price cannot be ruled out and could have an impact on the investment. However, if the United States were to adopt a federal or state carbon price policy, it is likely that Canada and Alberta would adopt a similar carbon cost. Yet it is also likely that other US oil suppliers will not have a home-country carbon price policy. In such a situation, if the United States does not account for carbon costs already incurred in Canada and Alberta, oil from oil sands—already a relatively high-cost source of supply—could be at a price disadvantage relative to other crude oils.

Figure 3 compares the effect of a relatively moderate carbon cost—$20 per metric ton—for various sources of crude oil. It illustrates the implications of US carbon-price policy on oil sands compared to other oil supply sources. The figure highlights the potential for oil sands

Figure 3

Illustrative Impact of Costs of Disconnected US and Canadian GHG Carbon Changes



Source: IHS CERA, assumes $20 per metric ton carbon cost for upstream and refining emissions in United States and Canada, plus Alberta charge of $15 per metric ton on 20 percent of emissions (assumes this amount is beyond intensity target). Scenerio assumes that Canadian carbon costs are not accounted for by US policy. In this case, emissions from Canadian oil sands are charged multiple times—by Canada, Alberta, and the United States.
10207-4

to incur "multiple charging" of the same carbon molecule (upstream emissions are charged three times—by Canada, Alberta, and the United States). Oil sands producers are price takers that must compete with other sources of supply; therefore this "extra carbon cost" could increase costs for oil sands producers, potentially lowering the return on investments and hurting oil sands economics vis-à-vis other crude oil sources.[1] Though this scenario is deemed reasonably unlikely (considering the integrated nature of the Canadian and US economies and expectations that future carbon policy would be harmonized), it highlights the potential impact if carbon price policy is not coordinated among provinces, states, and countries.

POLICY AREA FOUR: LOW-CARBON FUEL STANDARD

LCFS Policy and GHG Reductions

The goal of LCFS is to displace petroleum in the transportation sector with alternative fuels that have lower GHG emissions. The metric for measuring "lower emissions" is the well-to-wheels GHG intensity. Current laws call for reductions of up to 10 percent in the well-to-wheels intensity of fuel, phasing in over time. Fuel suppliers are responsible for compliance and must offer lower-carbon fuels for sale.[2]

LCFS are designed to increase consumption of lower-carbon transportation fuels without choosing a "winning" technology. The LCFS is similar to the RFS policy in this regard, because it mandates higher consumption of lower-carbon alternative fuels. However, a key difference is that RFS specifies biofuels for meeting the mandate, whereas LCFS allows any lower-carbon alternative (for instance, biofuels, electricity, hydrogen, or natural gas) to be used. LCFS policies were developed with the goal of filling "gaps" in other policies. Assuming low prices, carbon-price policies are not likely to make significant reductions in the GHG emissions from the transportation sector, and RFS polices do not take into account the potential for alternative vehicle technologies such as PHEVs/BEVs or natural gas vehicles (NGVs) to reduce GHG emissions.

Jurisdictions Adopting LCFS

Jurisdictions that have adopted LCFS include California, British Columbia, and the European Union. The outlook for a US federal LCFS is unlikely at least in the next decade. However, California's LCFS went into effect on January 12, 2010.[3] The California standard mandates

1. It is possible that oil sands economics will not be materially affected by carbon costs if extra carbon costs are offset by lower taxes or less government take.
2. Achieving a 10 percent reduction in life-cycle emissions solely by offering lower-carbon petroleum-based fuels is very unlikely. For petroleum-based fuels 70 to 80 percent of life-cycle GHG emissions occur in the combustion phase (as exhaust from the vehicle tailpipe). These tailpipe emissions are outside the control of the fuel supplier and are an inevitable result of fuel use. To meet the mandate with petroleum fuels, the 10 percent reduction in *overall* (i.e., well-to-wheels) GHG intensity must occur in the noncombustion, or well-to-retail pump, part of the life cycle. This corresponds to a reduction of approximately one third to one half in well-to-retail pump GHG emissions (those from producing oil, refining it, and distributing it to the retail pump). Even with greater efficiency in production and refining, and CCS, this level of reductions is not practical.
3. There are, however, ongoing lawsuits challenging California's LCFS on the basis of conflict with the Federal Energy Independence and Security Act of 2007 and interference with interstate commerce.

a 10 percent reduction in the GHG intensity of transportation fuels sold in the state by 2020.

In addition to California, several other US states are considering an LCFS. Together the states implementing or considering an LCFS represent 50 percent of the US gasoline market. A group of states in the Northeast and Mid-Atlantic signed a letter of intent at the end of 2009 to jointly review an LCFS policy and plans to develop a draft framework in 2011.[1] A group of ten Midwest states has been working toward an LCFS since 2007.[2] Oregon is expected to release its draft LCFS design this year, and Washington is also discussing adoption of an LCFS.

Potential GHG Reductions

If the targets are met, California estimates that the LCFS would reduce GHG emissions by 15 mt per year by 2020—equivalent to the annual emissions from four coal-fired power plants.[3] However, this calculation assumes that the LCFS is the only policy encouraging the adoption of low-carbon alternative fuels. It does not consider the impact of the federal RFS2 which, if implemented as outlined by the EPA, would also provide GHG reductions for California—in the range of 13.8 mt per year.[4] Since the two policies encourage a transition to lower-carbon alternative fuels, and in the next decade biofuels are the most likely candidates for low-carbon alternatives, the benefits partly overlap. Consequently, the additional emission reductions resulting from California's program are reduced to the difference between the two estimates, or 1.2 mt per year, less than the annual emissions from one coal plant.

Challenges in Implementation: Substitutions and Sources

For the gasoline pool compliance options could include substituting volumes of petroleum gasoline with corn ethanol, sugarcane ethanol, cellulosic ethanol, electricity, natural gas, or some combination of these fuels.[5]

Factors beyond fuel suppliers' control will make complying with LCFS challenging over the next ten years. Limited availability of low-carbon fuels and limited adoption of vehicles that consume these fuels are the greatest challenges—similar to those faced by RFS2. For instance one option for gasoline pool compliance is blending 50 percent sugarcane ethanol and 50 percent gasoline. Another option is blending 85 percent low-carbon corn ethanol with 15 percent gasoline (i.e., the E85 blend). Yet as is the case with RFS2, distribution of

1. Membership comprises Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.
2. The group is Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Ohio, South Dakota, and Wisconsin.
3. Source: *Climate Change Scoping Plan: A Framework for Change,* California Air Resources Board (CARB), December 2008.
4. California is about 10 percent of the US transportation market, so we credit 10 percent of the total benefits estimated by EPA to California.
5. The initial emissions calculations for California's LCFS estimated that corn-based ethanol (which represents the vast majority of biofuels produced in the United States today) had life-cycle GHG emissions similar to those of petroleum gasoline. Therefore, corn ethanol blending was not a useful strategy to achieve LCFS compliance. However, in November 2010 California revised its emissions estimates for corn-based ethanol to 5 to 20 percent lower than gasoline. Hence now the lowest-carbon sources of corn ethanol can (narrowly) be used to comply with the state's LCFS.

these highly concentrated ethanol blends poses a number of challenges for fuel suppliers and requires FFVs in the fleet to consume the fuel.

Moreover availability of alternative fuels will likely continue to be limited. For California to meet its target with corn ethanol alone, the state would have to consume more ethanol than the United States currently produces. Likewise to meet the target with sugarcane ethanol, more sugarcane ethanol than Brazil produces today is required. Fuel suppliers will almost certainly use a combination of fuels to meet the LCFS mandate, but this would only temper biofuel supply bottlenecks, not alleviate them.

Natural gas and electricity are two additional compliance options with LCFS. Yet EVs are only now becoming available to consumers.[1] In the United States NGV sales have averaged about 1,500 vehicles per year. Limited infrastructure is one reason for slow NGV sales—refueling stations are rare. In IHS CERA's aggressive alternative vehicles scenario—called Meta—PHEVs, EVs, and NGVs displace less than 150,000 barrels per day of US gasoline demand by 2020. Even with a sharp increase in the sales of these alternative vehicles, in a ten-year time frame they will likely provide only modest help in complying with LCFS.

Regulation Complexity versus Efficacy

Regulating based on well-to-wheels emissions estimates requires a trade-off between the complexity of regulation and efficacy. Establishing broad categories of transportation fuels makes regulations simpler for fuel suppliers to comply with and simpler for regulators to enforce. EPA's RFS2 is structured this way; it assigns one emissions value for gasoline and diesel and a handful of broad groupings for biofuels. On the other hand a more granular approach to regulation may be more effective at reducing emissions by providing fuel producers with more incentive to reduce emissions from specific sources. California's LCFS takes this granular approach by establishing numerous categories for petroleum and specific estimates for each biofuel source and process technology. However, having many fuel categories increases the regulation's complexity, requiring suppliers to track the specific fuels that are consumed and to measure emissions for numerous fuel types rather than just a few. Data transparency is another issue in using the granular approach; gathering and verifying GHG emission data for each crude source is a formidable task.

Comparing the two current North American LCFS polices (British Columbia and California) illustrates the trade-offs between complexity and efficacy. The British Columbia mandate takes a simpler approach; it assumes one average well-to-wheels GHG emissions value each for petroleum gasoline and diesel, not differentiating among sources of crude oil used to produce gasoline or diesel. Additionally, it removes a key source of uncertainty in well-to-wheels estimates by excluding indirect emissions. Indirect emissions are difficult to estimate, and as a result there is a wide range of published estimates for well-to-wheels emissions from biofuels (see the box "Data Uncertainty Makes Well-to-wheels a Challenging Basis for Policy").

1. The amount of GHG reduction from using electricity in transportation depends on the source of the electricity. Coal-fired electricity can even increase in life-cycle GHG emissions over gasoline. Using the current California LCFS guidelines, California's average electricity mix (primarily natural gas) would result in about one third of the GHG emissions of a similar gasoline-powered vehicle. Source: Proposed Regulation to Implement the Low Carbon Fuel Standard—Appendix C, March 2009.

The California policy is more complicated. California's LCFS accounts for indirect emissions in its life-cycle emissions estimates for biofuels. It also differentiates among sources of crude oil, establishing an emissions intensity value for a baseline basket of crudes—consisting of major sources of crude oil currently refined in California.[1] Oil sands crudes are not included in this basket of crudes. If a refiner wants to import crude oil from a source not already in the baseline basket—one with upstream GHG emissions exceeding a fixed threshold—it must work with the regulator to establish a specific GHG emissions intensity value for the new crude supply.[2] Some oil sands supply (oil sands extracted using higher GHG-intense methods) would require such treatment.

California's rule—requiring that only new higher-carbon crude sources establish unique GHG intensity values—has been controversial. Canadian officials and industry players have expressed concern that this method discriminates against oil sands crudes compared to California's own high-emissions crude oil, potentially violating provisions of the North American Free Trade Agreement and of the World Trade Organization.

Implications for Oil and the Oil Sands: Potential Double Effect

The impact of LCFS policies on oil demand is difficult to estimate—it will depend on the alternative fuels used to comply. If very low-carbon alternatives such as yet-to-be developed cellulosic ethanol were available, only about 20 percent of oil demand would be displaced. If corn ethanol were the only available alternative fuel, in theory 85 percent of oil demand

Data Uncertainty Makes Well-to-wheels a Challenging Basis for Policy

Estimating the well-to-wheels emissions of fuels—whether for crude oils or alternative fuels—is an evolving and still inexact discipline, making these values a challenging basis for policy. Inconsistencies among estimates result from a variety of sources: data (quality, availability, and modeling assumptions), allocation of emissions to the various products produced in the refinery or during oil extraction, and the definition of boundaries for estimating emissions.* For these reasons estimates of well-to-wheels GHG emissions can vary significantly. The carbon emissions reduction benefit that a given policy could be expected to deliver is often a subject of debate. Comparing the renewable fuel emissions estimates in RFS2 with the CARB estimates used in California's LCFS provides an illustration of this variance (see Figure 4).

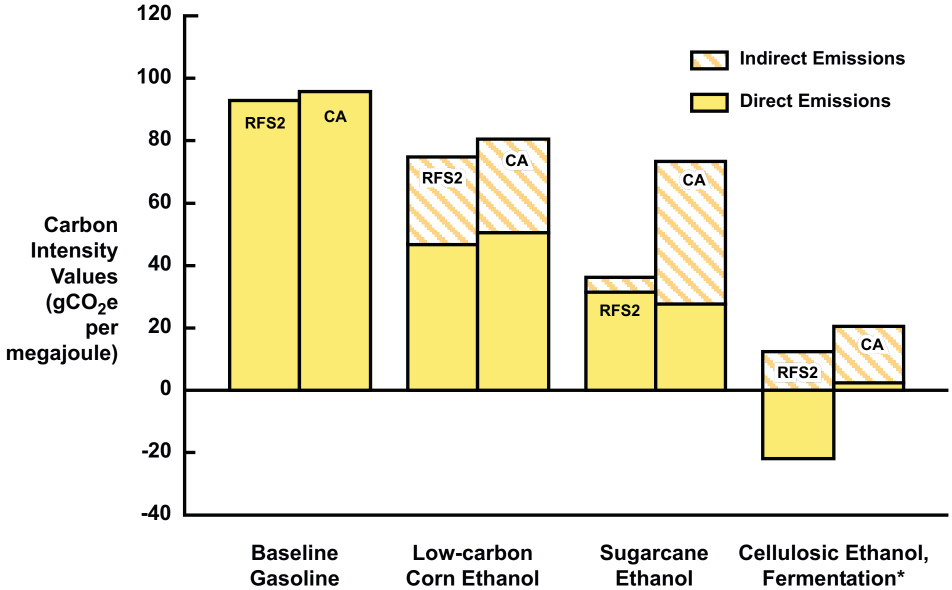
The two policies differ significantly in their estimate of the GHG emissions avoided by switching from petroleum to various alternative fuels. The largest source of difference is in the estimate of indirect land emissions for biofuels—an area of great uncertainty and therefore wide-ranging estimates.

*For a more detailed discussion of the sources of inconsistencies in well-to-wheels GHG emission estimates, refer to the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right.*

1. California's baseline basket of crudes consists of all sources of crude oil that made up 2 percent or more of California refineries' feedstock in 2007. The baseline includes California heavy oil production, an oil source on par with the oil sands in well-to-wheels GHG emissions.
2. Crudes with upstream GHG emissions greater than 15 grams of CO_2e (gCO_2e) per megajoule (MJ) cannot use the baseline value. The average crude oil refined in California today has upstream emissions of about 8 gCO_2e per MJ, whereas oil sands crudes vary from about 13 to 19 gCO_2e per MJ.

Figure 4

Renewable Substitutes for Gasoline—
Comparison Between GHG Emission Estimates
for California LCFS and EPA RFS2



Source: EPA RFS Final Rule (March 2010); CARB Feb 2011 proposed look-up tables.
Note: Cellulosic data from CARB proposed regulation (March 2009)
All estimates are well-to-wheel emissions. Low-carbon ethanol assumes
EPA (Gas Fired Dry Mill) and CARB (California Dry Mill Wet DSG NG).
10207-5

could be displaced, although this scenario is not practical because of limited volumes of ethanol. In the next decade, while alternative fuels are in short supply, it is expected that jurisdictions would charge a noncompliance penalty. Assuming the penalty were $20 per metric ton, this equates to about $1 of extra cost per barrel for the average crude.

The extent to which LCFS affects oil sands depends on the style of LCFS chosen. A British Columbia–style policy (one with one well-to-wheels emissions values assigned for all petroleum) would have no implications for oil sands beyond those for oil from other sources. By contrast, a policy mirroring that of California (one that distinguishes among crude oil sources) has specific implications for oil sands. On average wholly derived oil sands products are 10 percent higher in carbon intensity than the average US barrel consumed on a well-to-wheels basis.[1] Therefore, to meet the California mandate, a fuel supplier would have to supply enough alternative fuels to achieve a 10 percent emissions reduction just to bring oil sands to the average crude baseline. Then the supplier would have to supply more alternative fuels to achieve a further 10 percent emissions reduction to meet the mandate. Thus oil sands crudes require about twice as much alternative fuel blending as “average” crudes to comply with the mandate. Given this equation, if oil sands crudes were consumed in notable volumes in California, the volume of oil sands displaced by the policy would be

1. Average emissions from mining bitumen to produce synthetic crude oil and bitumen production.

about two times more than the “average crude.” Likewise, for a noncompliance penalty—the oil sands cost would be double ($20 per metric ton equates to $2 of extra cost per oil sands barrel). The noncompliance penalty could turn into an instance of “multiple-charging” the same carbon molecule. If for example a price for carbon has already been levied (by means of another carbon price policy—either a state, provincial, or federal rule), the LCFS penalty would in effect charge for the same carbon again.

PART III: CONCLUSION

The policy mechanisms that aim to reduce GHG emissions related to US transportation vary both in their potential to reduce GHG emissions, and therefore oil demand, significantly and in the probability that they will be implemented widely. A mix of policies has already been implemented on a national scale and others only at a state level. Federal policies already implemented include the EPA mobile and stationary GHG emissions regulations and RFS2. However, the federal government has not implemented an LCFS or a price on carbon. California is the only US state with an LCFS in place, and although one state group has implemented a cap-and-trade scheme for the utility sector, outside of California there is no cap-and-trade or carbon tax policy affecting US transport.

CHALLENGES IN POLICY IMPLEMENTATION

Looking ahead, the implementation of a federal carbon price policy and federal LCFS appears unlikely at least within the next decade. However, it is more likely that new state-level policies could develop. Even policies already established at a federal level—the EPA mobile and stationary regulations and RFS2—will likely face implementation challenges. Under EPA mobile rules automakers must develop and sell potentially more costly vehicle technologies. Moreover if the 2025 fuel efficiency standards (once established by EPA and DOT) are seen by legislators as too strict, they may attempt to block the mandate. With the RFS2 a key challenge is fuel suppliers' ability to meet the targets for using advanced biofuels, both fuel supply and consumption are likely to create bottlenecks.

US policy remains uncertain, with constantly evolving ideas pertaining to climate change and clean energy. Recently the US federal government appears to be shifting priorities toward clean energy investments as opposed to climate change initiatives. Both state and federal governments are attending more to job creation, economic growth, and fiscal prudence. Political considerations will remain important factors shaping US GHG policy. Meaningful carbon reductions often equate to higher energy costs—for the taxpayer, corporation, or consumer—with the potential for changing political outcomes.

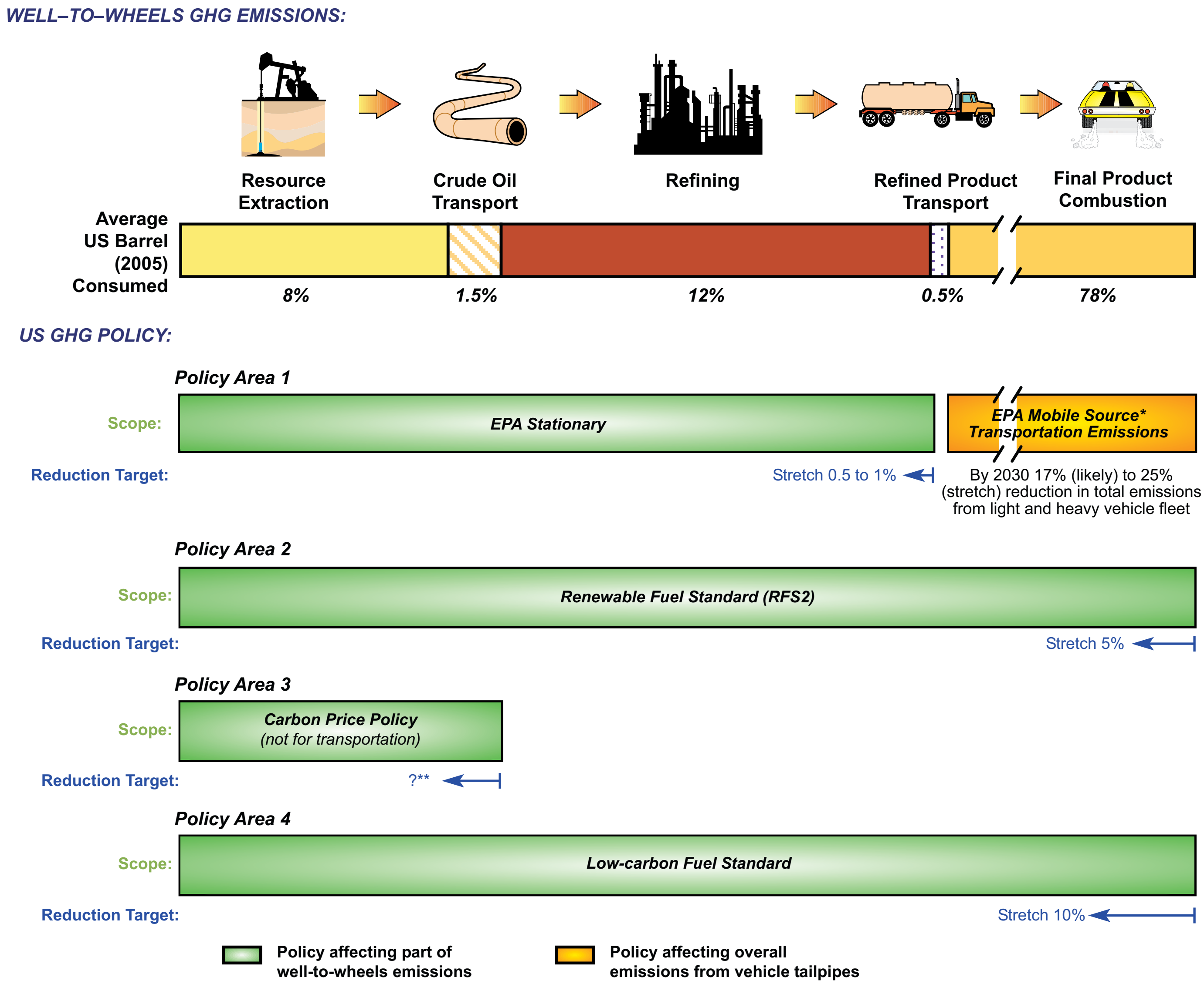
IMPLICATIONS FOR GHG EMISSIONS REDUCTIONS

Though some of the policies analyzed in this paper target unique GHG reductions, many of the policies overlap in scope, leading to some duplication of efforts (see Figure 5).

Policies that specifically target fuel consumption are the most effective at reducing US transportation GHG emissions. Therefore the EPA Mobile Source Transportation Emission rules have the most potential to reduce US GHG emissions by 2030; reductions of between 332 mt CO_2e per year (assuming 35 mpg for light duty in 2016 plus plans for heavy duty) and 448 mt CO_2e per year (stretch case of 60 mpg for light duty in 2025 plus plans for heavy duty). Put another way, by 2030 this policy could reduce all US GHG emissions by 5 to 10 percent (compared with a case with no vehicle fuel economy improvements). These regulations are effective because they target emissions from the vehicle—which are responsible for 70 to 80 percent of the emissions related to producing and consuming transportation fuels.

Figure 5

US GHG Policy: GHG Reduction Targets and Scope



Source: IHS CERA.
*By improving vehicle efficiency, the total emissions from transport will be reduced, effectively lowering the combustion emissions per mile driven. However, no mitigation strategy for petroleum-fueled vehicles can reduce emissions per unit of energy, which is the basis of the well-to-wheels combustion emissions (78 percent of the emissions for average crude consumed in the United States).
**Depending on the price associated with emitting carbon, the total amount of reductions will vary.
10207-7

The other policies examined in this paper (EPA stationary mandates, RFS2, carbon tax, and LCFS) result in significantly more modest reductions in GHG emissions (see Table 1).

Table 1

GHG Reduction Policy Comparisons

(GHG reductions in million metric tons of CO_2e per year)

Policy	High Case	Likely Case	Probability Policy Will Be Implemented Widely	Status
EPA stationary	19 (4–5 average-size coal plants)	Much less	Medium—(regulated now but with a chance the EPA will be slowed)	BACT is regulated; NSPS is under development
EPA mobile	448 (116 average-size coal plants)	2016 mandate more than 332 (86 average-size coal plants)	Likely Case—High High Case—Medium	Current "likely case" is regulation at federal level. "High case" could be reduced by legislators
RPS2	138 (32 average-size coal plants)	20 (5 average-size coal plants)	High—In law today, but not likely to meet current targets by 2022	Now regulated at federal level
Carbon price	Negligible	Negligible	Low	Only in California for transportation starting in 2015.
LCFS California	15 (4 average-size coal plants). About 13.8 of this may have resulted from EPA policy regardless of LCFS	Less	Medium—In law today but not likely to meet current targets by 2020	In law today for California; other states looking to adopt similar policy.

Source: IHS CERA.

SLOW MOTION OIL DEMAND DECLINE

In IHS CERA's expected policy case (a scenario in which RFS2 and LCFS policies do not fully meet current mandates, and EPA introduces less-stringent fuel efficiency standards for 2025), by 2030 US petroleum-based demand is just slightly below current levels, near 18 mbd compared with 20 mbd without these policies. The relatively modest decline in petroleum-based oil demand (not including biofuels) illustrates the "slow motion" effect of GHG policies. The slow response is imposed by two factors: the long time horizon required to replace the existing vehicle fleet and the ongoing demand growth for transportation.[1] In our stretch case all policies overcome implementation challenges, achieve their mandates, and provide larger reductions in emissions and US oil demand; and demand for petroleum-based oil (not including biofuels) could drop below 16 mbd by 2030.

OIL SANDS IMPLICATIONS

Though US petroleum-based oil demand is on a slow-motion downward trend, Canadian oil supply is on the opposite trajectory and pace—likely doubling in the next decade. Could oil sands supply outgrow its only notable market? Not likely; even in our stretch case—with significant lower US crude demand and very high oil sands growth—the United States could absorb all oil sands supply and at the same time significantly reduce the need for other foreign imports.[2] Even beyond 2030 the United States will remain one of the world's largest oil markets and a natural and viable export market for the Canadian oil sands.

Yet, given the higher carbon intensity of oil sands crudes compared with the "average" crude used in the United States, some of the policies analyzed in this report, if adopted more widely either on a nationwide scale or by states, could disproportionately raise the cost of oil sands and decrease its competitiveness compared to other supply options. One of these policies is a California-style LCFS that would require fuel suppliers to use a greater amount of potentially costly low-carbon alternative fuels (such as biofuels, electricity, or natural gas) to offset the carbon intensity of oil sands crudes. Another is carbon price policy, specifically rules that do not account for carbon costs already incurred in Canada, resulting in charging the same carbon molecule multiple times, creating potentially higher costs for Canadian producers, and lowering returns on oil sands investments.

The uncertainty about the final effects of US GHG policy on oil and on oil sands is already adding risk to billions of dollars in oil sands investments. If US policy were to considerably weaken oil sands economics or market access, this would create a corresponding incentive for oil sands to reach new, more profitable, destinations—with consequences for US energy security. As a result, even if oil sands are able eventually to navigate these policies (especially the ones that affect them more than other sources of oil supply), the policies still have potential implications that will shape the future role of the oil sands in the fabric of North American energy security, economic growth, and environmental outcomes.

1. Today's vehicle fleet is an impediment to reducing oil demand. A typical car is on the road for 12 to 15 years before it is replaced, and other vehicles have even longer lives.
2. Assuming by 2030 US domestic supply of between 5 and 6 mbd and a high stretch case for oil sands production of 5.7 mbd, compared with 1.35 mbd in 2009.

REPORT PARTICIPANTS AND REVIEWERS

On November 18, 2010, IHS CERA hosted a focus group meeting in Washington, DC bringing together oil sands stakeholders to discuss perspectives on the key issues related to US GHG policy and oil sands. 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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Imperial Oil Ltd.
In Situ Oil Sands Alliance (IOSA)
Marathon Oil Corporation
National Round Table on the Environment and the Economy (NRTEE)
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IHS CERA TEAM

James Burkhard, Managing Director of IHS CERA's Global Oil Group, leads the team of IHS CERA experts that analyze and assess upstream and downstream market conditions and changes in the oil and gas industry's competitive environment. A foundation of this work is detailed short- and long-term outlooks for global crude oil and refined products markets that are integrated with outlooks for other energy sources, economic growth, geopolitics, and security. Mr. Burkhard's expertise covers geopolitics, industry dynamics, and global oil demand and supply trends.

Mr. Burkhard also leads the IHS CERA Global Energy Scenarios effort, which combines energy, economic, and security expertise across the IHS Insight businesses into a comprehensive, scenarios-based framework for assessing and projecting global and regional energy market and industry dynamics. Previously he led the IHS CERA study *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030,* which encompassed the oil, gas, and electricity sectors. He was also the director of the IHS CERA Multiclient Study *Potential versus Reality: West African Oil and Gas to 2020.* He is the coauthor of IHS CERA's respected *World Oil Watch,* which analyzes short- to medium-term developments in the oil market. In addition to leading IHS CERA's oil research, Mr. Burkhard served on the US National Petroleum Council (NPC) committee that provided recommendations on US oil and gas policy to the US Secretary of Energy. He led the team that developed demand-oriented recommendations that were published in the 2007 NPC report *Facing the Hard Truths About Energy.* Before joining IHS CERA Mr. Burkhard was a member of the United States Peace Corps in Niger, West Africa. He directed infrastructure projects to improve water availability and credit facilities. He was also a field operator for Rod Electric. Mr. Burkhard holds a BA from Hamline University and an MS from the School of Foreign Service at Georgetown University.

Jackie Forrest, IHS CERA Director, Global Oil, leads the research effort for the IHS CERA Oil Sands Energy Dialogue. Her expertise encompasses all aspects of petroleum evaluations, including refining, processing, upgrading, and products. She actively monitors emerging strategic trends related to oil sands including capital projects, economics, policy, environment, and markets. She is the author of several IHS CERA Private Reports, including an investigation of US heavy crude supply and prices and West Texas Intermediate's price disconnect from the global oil market. Additional contributions to research include reports on the life-cycle emissions from crude oil, the impacts of low-carbon fuel standards, and the role of oil sands in US oil supply. Ms. Forrest was the IHS CERA project manager for the Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance,* a comprehensive assessment of the benefits, risks, and issues associated with oil sands development. Before joining IHS CERA Ms. Forrest was a consultant in the oil industry, focusing on technical and economic evaluations of refining and oil sands projects. Ms. Forrest is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University.

Rob Barnett, IHS CERA Associate Director, specializes in energy sector economics, environmental policy and strategy, and emissions markets. Mr. Barnett is responsible for the climate change and clean energy assumptions that underpin IHS CERA's Global Scenarios, including carbon dioxide emissions price outlooks. He is the author of numerous IHS CERA reports on topics that include global emissions trends, US clean air regulations, Chinese greenhouse gas (GHG) emissions trends and policy, life-cycle GHG emissions accounting, cost recovery for pollution control expenditures, and European emissions trading. He led the environmental market analysis for the IHS CERA Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance*. He also contributed to the IHS CERA Multiclient Studies *Crossing the Divide: The Future of Clean Energy; Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030;* and *Clearing the Air: Scenarios for the Future of US Emissions Markets*. Prior to joining IHS CERA Mr. Barnett worked for Clemson's Power Quality and Industrial Applications Laboratory, where he modeled electric power systems to assess the impact of distributed generation. Mr. Barnett holds BS and MS degrees from Clemson University and an MA from Boston University.

Jeff Meyer, IHS CERA Associate, Global Oil, focuses on oil market fundamentals and market developments. He contributes to the IHS CERA *World Oil Watch* and monthly global oil Market Briefing. Prior to joining IHS CERA Mr. Meyer was a correspondent for Dow Jones Newswires, based in Shanghai, where he covered China's capital markets and economy. At Dow Jones he also contributed to *The Wall Street Journal.* He has held short-term positions with J.P. Morgan's Emerging Asia economic research team and with the US Treasury's Office of South and Southeast Asia. Mr. Meyer holds a BA from Haverford College and master's degrees from New York University and from Johns Hopkins University School of Advanced International Studies. He is proficient in Mandarin.