

A Ceres Report



CANADA'S OIL SANDS SHRINKING WINDOW OF OPPORTUNITY

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RiskMetrics Group

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Foreword

Oil, the lifeblood of transportation, is a key driver of the global economy. As the world comes out of recession, oil demand is resuming its inexorable rise, with the U.S. alone consuming 23 percent of global supplies in 2008. While just over half of U.S. oil comes from overseas countries like Venezuela, Saudi Arabia and Iraq, the fastest growing source is from North America — in particular, from the Gulf of Mexico and Canada's vast oil sands regions. Oil production from these two areas has grown to 3 million barrels a day in recent years, supplying more than 15 percent of total U.S. oil needs.

Yet, while this growing reliance on locally produced oil has some economic and perceived national security benefits, it also comes loaded with significant costs. While all oil extraction has environmental impacts, oil production from challenging frontier areas like the deepwater Gulf of Mexico and Canada's oil sands carries higher-than-average risks. The BP oil spill in the Gulf of Mexico has made these risks acutely tangible for investors, with BP's shareholder value taking a \$30 billion hit amid a wave of lawsuits by fishermen and other local industry groups.

The risks for companies involved in developing Canada's oil sands — the largest energy project in the world, and the focus of this report — are arguably greater than those in the Gulf of Mexico. Most of these risks are related to the energy- and water-intensive nature of oil sands production, risks that will only increase as the industry seeks to double or even triple production in a world that is increasingly becoming water- and carbon-constrained. Oil sands production requires extracting synthetic crude oil from the highly viscous bitumen buried across vast stretches of Alberta, Canada.

One of the key risks facing investors is the narrow profit window for oil sands production. The oil sands are the world's most expensive source of new oil, and new production requires prices of at least \$65 per barrel, and potentially as high as \$95 per barrel, to make economic sense. Increasing environmental regulations, including emerging carbon limits, will cause this floor price to rise. Adding to the project's risk profile are resource constraints that could limit future production — specifically, adequate water and natural gas supplies that are linchpins for boosting oil production.

Finding a marketplace for ever-increasing oil sands production is another major question. Presently, the vast majority of the 1.3 million barrels being produced every day flows to the United States. This market is jeopardized, however, by emerging low-carbon fuel standards in the U.S. that will require a lower carbon intensity in transportation fuels. In order to have access to these markets, oil sands output will likely have to be mixed with next-generation biofuels which are not yet being produced on a commercial scale. These fuel standards, already adopted in California, will put carbon-intensive oil sands fuel at a distinct disadvantage.


Another alternative is transporting these oils west to China and other Asian markets. However, there is strong opposition to building pipelines to Canada's West Coast from Aboriginal communities who have significant rights under the Canadian Constitution.

Added together, these wide-ranging challenges will make oil sands production increasingly risky in the years ahead. Among the report's conclusions is that global oil prices will need to remain high — possibly approaching \$100 a barrel — to justify the planned \$120 billion expansion in the oil sands region in the next decade. Oil sands producers must also be mindful that if global oil prices get too high, above \$120-\$150 a barrel, it will likely reduce global oil demand and shift markets in favor of alternative fuels. Bottom line: oil sand producers are operating in a narrowing window of profitability.

Investors are right to be pushing oil companies to provide detailed explanations on how they are responding to these wide-ranging challenges. Shareholder resolutions requesting such disclosure were filed with many leading oil sands producers this year, including BP, Shell, Exxon/Mobil and ConocoPhillips.

These resolutions — and the report's findings — are a wake up call for oil companies to move quickly to examine and respond to these multiple challenges. Companies such as Suncor have shown a willingness to tackle these issues, both by improving their disclosure and attempting to address tough environmental challenges such as remediating the vast land areas now covered by polluted tailings ponds.

All oil sands companies should be tackling these challenges and we hope this report will expedite such action. Likewise, investors should be pressing companies to analyze and mitigate their potential risk exposure from this unconventional oil extraction project that has already attracted financial commitments of \$200 billion, with potentially much more to come.

A handwritten signature in black ink that reads "Mindy A. Lubber". The signature is written in a cursive, flowing style.

Mindy S. Lubber
President, Ceres
Director, Investor Network on Climate Risk

Executive Summary

Canada's vast oil sands are the focus of the world's largest energy project. The Province of Alberta is home to the world's second largest hydrocarbon basin, after Saudi Arabia, containing approximately 175 billion barrels of proved reserves. Virtually every major Canadian and international oil company, including Suncor, ExxonMobil, Shell and ConocoPhillips, has a financial stake in this resource, with \$200 billion committed to current and future oil extraction projects covering an area the size of Greece. These companies are betting that demand for higher-priced oil is here to stay. As oil prices climb above \$80 per barrel, producers are optimistic that they can double oil sands production over the coming decade, and more than triple output by 2030 to produce more than 4 million barrels per day. That is more than double current oil production in the Gulf of Mexico.

However, oil sands production is expensive and faces significant risks associated with its environmental and social impacts. This report concludes that if the industry does not take steps to aggressively manage these risks, its long-term growth is in doubt.

Production of crude oil from highly viscous bitumen requires substantial amounts of energy and water; hence, oil sands production in Alberta comes at a high financial price. In addition, the process exacts a heavy environmental toll. Bitumen mining mars the landscape and consumes large volumes of water that end up in toxic tailings ponds. In-situ production fragments wildlife habitat and is extremely carbon-intensive. Restoring this vital ecosystem will require sustained investments in land reclamation and water treatment projects, which presents one of this industry's biggest long-term challenges.

At the same time, oil sands development is turning an expanding section of Canada's vast boreal forest, one of the world's largest carbon sinks, into one of the fastest-growing manmade sources of carbon dioxide emissions. With continued expansion, oil sands operations are forecast to rise from 5% to 15% of Canada's total CO₂ emissions by 2020, working against national and global goals to achieve substantial GHG emission reductions. A CAD \$15 per ton levy imposed on CO₂ emissions in Alberta in 2007 has had little demonstrable effect in altering companies' production plans. However, the effects of climate regulations, including emerging Low Carbon Fuel Standards (LCFS), in the U.S. and Canada will likely apply added pressure on the industry to reduce its growing carbon footprint.

This report examines how carbon and land reclamation regulations, climate change and other environmental and social issues may adversely affect the future of oil sands development in Alberta. Multiple risks are addressed in detail. Although Alberta is considered a safe haven for oil producers relative to other more politically volatile regions of the world, Canada's own Aboriginal communities pose a potential roadblock to oil sands' expansion, and some have already called for a moratorium on new projects and pipelines that would open new key trade routes for distributing oil. Canada's dominant oil export market, the United States, is also undergoing a wholesale review of its energy policy. With a renewed focus on promoting energy efficiency and low-carbon technologies, the United States could substantially reduce demand for this carbon-intensive fuel.

As outlined in the chapters that follow, this report concludes that the rush to develop oil sands brings many risks for companies and investors. Rising production costs and asset retirement obligations could erode the balance sheets of these companies. Carbon costs and mounting environmental regulations could detract from their bottom lines. Companies must be willing to invest upfront to address these challenges when designing new projects, while recognizing that cost-effective solutions in many instances do not yet exist. This quandary leaves oil sands producers exposed to growing risks and a shrinking window of opportunity that may close over time.

Key Report Findings

Canada's oil sands companies operate in a shrinking window of opportunity.

These producers of unconventional crude oil face volatile global energy markets and rising production costs. They need global oil prices to stay above at least \$65 per barrel—and possibly above \$95 per barrel—to justify \$120 billion in planned expansion projects over the next decade. The production floor price for oil sands is rising with the onset of carbon pricing, higher input commodity prices and growing regulatory expenditures for water treatment and land reclamation. At the same time, global oil prices may rise to the point where they quash petroleum demand and permanently shift markets in favor of alternative fuels. This upper price limit may be in a range of \$120–\$150 per barrel. Such a relatively low ceiling combined with the rising floor price creates a narrow window for future oil sands development that could shrink and possibly close altogether if the industry is unable to manage these risks and significantly reduce the costs of production.

Some Aboriginal communities and investors in Canada support a moratorium on new oil sands projects and pipelines.

The collapse in oil prices in 2008 brought about a de-facto moratorium on new oil sands projects. While that freeze appears to be lifting, Aboriginal communities with rights granted under the Canadian constitution still could block significant expansion. If oil sands production is limited to current operating projects in addition to those under construction, estimated total production volume would rise from 1.2 million barrels/day (mmbbl/d) in 2008 to 2.0 mmbbl/d by 2015. Oil sands producers have their sights set on much higher output, however. With rising oil prices, they believe oil sands volume could double by 2020, triple by 2030 and reach still higher volumes if oil prices are sustained at levels well above today's prices.

The United States is likely to remain the dominant market for Canadian oil sands producers for the foreseeable future. Canada has been the United States' largest foreign oil supplier since 2004, surpassing Saudi Arabia; more than two-thirds of Canadian oil production was exported to the U.S. market in 2008. Canada's portion of U.S. oil imports is projected to remain at about 22% through 2035, with oil sands' contribution rising from 59% to more than 80% of the total Canadian supply after 2020. Efforts to build oil sands pipelines to Canada's west coast for exports to Asia so far have been slowed by Aboriginal and community opposition. This leaves Canadian oil sands producers highly dependent on the U.S. market and the future course of its energy policy.

Newly introduced LCFS rules in the U.S. and Canada are intended to reduce the carbon intensity of transportation fuels, putting oil sands producers at a disadvantage. The LCFS rules require a gradual decrease in the full life cycle carbon emissions of these fuels, which poses a particular challenge for oil sands because of their high carbon intensity and low energy return on energy invested (EROEI). It takes three times more units of energy to extract bitumen from oil sands than oil from conventional wells. Only seven units of energy are returned for each unit of energy invested to extract bitumen from oil sands (resulting in an EROEI ratio of 7:1), whereas pumping oil from conventional wells yields a 22:1 ratio. After upgrading and refining, the EROEI of oil sands falls to just 3:1. This puts oil sands at a distinct disadvantage to conventional petroleum on a carbon-intensity basis. Measuring emissions from the time of extraction through end use as motor fuels—a “field-to-wheels” analysis—oil sands derived fuels are 12% more carbon-intensive on average than those derived from conventional oil. California adopted an LCFS standard in 2009, and similar regulations are under consideration in more than half of the U.S. states and four Canadian provinces. If one quarter of the U.S. motor vehicle market were subject to an LCFS standard requiring a 10% reduction in the average carbon intensity of gasoline by 2020 (equal to a 20% reduction for synthetic crude oil), with a further 10% reduction required by 2030, the resulting demand reduction could curtail oil sands production volume by 13.5% compared to our estimated baseline forecast of 3.7 mbbbl/d in 2030. If an LCFS standard was adopted by all 50 U.S. states, Canadian oil sands production could be further curtailed, to 2.5 mbbbl/d in 2030, a 33% decline relative to our baseline forecast.

Growing availability of renewable transportation fuels would support oil sands producers’ compliance with LCFS. To offset the higher carbon intensity of oil sands, low-carbon renewable fuels can be blended with this synthetic crude to meet the reduced carbon-intensity targets under an LCFS. Advanced renewable fuels like cellulosic ethanol are the preferred blending option because they have less than half the carbon intensity of conventional petroleum and lower carbon intensity than widely available corn-based ethanol. However, advanced renewable fuels are not yet produced in large commercial quantities. This gives oil sands producers a strong incentive to support the growth of this industry. In the unlikely event that *no* options emerge to enable Canadian oil sands producers to comply with a federal LCFS in the United States, demand could fall below the 2.0 mbbbl/d production volume that oil sands producers already have in operation and under construction.

Other carbon offset options for oil sands producers may be costly and difficult to obtain. Carbon capture and sequestration (CCS) is a critical technology that could help reduce the carbon-intensity of oil sands production relative to conventional crude oil. However, only the upgrading and hydrogen processing elements of the oil sands production process yield high-CO₂ waste streams that lend themselves to ready capture. Moreover, pipelines would have to be built (extending up to 1,000 miles) to transport this captured CO₂ to geographically suitable regions, and assurances would be needed that this CO₂ would remain safely sequestered in underground reservoirs for many centuries. Projected initial costs of CCS for oil sands range from CAD \$70-150 per ton of CO₂ sequestered. Other types of carbon offset credits may be available within the transportation sector. However, these offsets, too, are likely to be expensive and may not be available in the quantities that oil sands producers would require. Because conventional oil producers would need proportionately fewer credits to meet LCFS rules, they will be the likely drivers of this market. This may

leave oil sands producers with only the most expensive LCFS purchase options—or possibly none at all. We estimate that LCFS credits selling for \$100/ton would have the effect of raising the price of oil sands production by \$11.40 per barrel to achieve a 10% carbon-intensity reduction target (equal to a 20% reduction for synthetic crude).

Water shortages could emerge as an oil sands production constraint by 2014. Oil sands production is highly water-intensive, with up to four barrels of water consumed for every barrel of oil produced from surface mining projects. (The ratio is less than 1:1 for underground, in-situ projects.) Water withdrawals from the Athabasca River watershed are already restricted during winter months to protect fish habitat. If oil sands production volume grows according to companies' estimates, some oil sands mining operations could exceed their wintertime allowances by as early as 2014, causing possible production interruptions. Along with new provincial water control regulations, this is likely to prompt oil sands producers to make significant additional investments in water storage, treatment and recycling facilities. Climate change may exacerbate this water management challenge. Glaciers that feed into this watershed are already shrinking, and some scientific studies forecast that the Athabasca River's water flow could shrink by 50% in winter months by mid-century. This places oil sands producers in possible competition with other agricultural, municipal and industrial water consumers in Alberta.

Land reclamation presents growing operating costs and liability for some oil sands producers. After 40 years of production, no oil sands company has fully reclaimed tailings ponds created by development. That is because the fine particulates in toxic mining waste take decades to settle out in tailings ponds. Such tailing ponds—already covering an area the size of Washington, D.C.—pose risks of contaminating adjoining soil and water resources, and present health problems in downstream communities as well as the risk of a catastrophic breach. Alberta's Directive 74 requires oil sands miners to speed up the remediation process of existing ponds and progressively treat tailings. This may pose a particular challenge to some of the oil sands industry's biggest legacy miners. For example, if bioremediation is used to expedite this treatment process, our analysis finds that Canadian Oil Sands Trust (COST) could see a 10-26% increase in its debt-to-capitalization ratio to cover its added asset retirement obligations.

Opposition by First Nations and other Aboriginal communities poses a growing material risk to oil sands producers. Some Aboriginal leaders have passed joint resolutions calling for a moratorium on new oil sands project approvals until appropriate engagement and consultation with their local governments takes place. Canada's Constitution recognizes the rights of these Aboriginal communities to protect their traditional livelihoods, including a right to be consulted about development activities and to have their hunting and fishing rights accommodated. To date, neither the Albertan nor Canadian governments, nor any oil sands producers, have engaged with Aboriginal communities on the basis of Free, Prior and Informed Consent, which is their preferred means of engagement. This raises the specter of protracted legal battles and — in the worst case — possible annulment of oil sands leases that could compromise the industry's future expansion plans.

Recommendations for Future Oil Sands Development

Investment in the oil sands has grown in large part because the industry has few other options for developing significant new reserves. Some industry analysts have concluded that more than half of the oil that is open to investment by western companies is now located in Canada's oil sands. As global oil demand continues to grow, so too will pressure to expand this resource. What this report underscores is that oil sands investment is not without significant risks. Companies should proceed with caution and make clear plans for managing risks associated with carbon emissions, water scarcity and land reclamation.

Oil sands producers should review the lasting impacts of their proposed development plans and pursue more pro-active, incremental strategies.

Community opposition and investor concerns about oil sands development will persist until oil sands companies do a better job of articulating their plans for ongoing community and stakeholder engagement, land use planning, water management and carbon mitigation. Oil sands producers would do well to view this as an opportunity to examine how their financial prospects will be affected by rising production costs, increased liabilities and changing global energy policies that narrow the window on future oil sands development. Oil sands companies should also be disclosing information from these more detailed evaluations to investors.

If the aforementioned energy and water issues could be remedied, stronger ties between Canadian oil sands producers and the U.S. biofuel industry could lead to a greener North American economy. The spread of LCFS standards from California to other regions of the United States and Canada could foster a closer working relationship on both sides of the border. Existing Canadian oil sands pipelines feed mainly into the U.S. Midwest, which has substantial infrastructure in place to process this fuel and combine it with significant biofuel production capacity. Building on this relationship with new investments in advanced renewable fuels would help oil sands derived fuel achieve LCFS standards, spur more employment in clean technology industries and promote regional energy independence that could enable North America to compete more effectively against Europe and Asia as they advance their own low-carbon economies.

A more comprehensive and better articulated long-term strategy will give investors a clearer picture about the scale and pace at which appropriate development should take place. At the same time, companies will gain more confidence in their own strategic planning decisions and be more likely to gain backing from wary stakeholders, investors and policymakers. The alternative leaves these vital questions unanswered and only raises the stakes in the multi-billion dollar gamble that has become oil sands development in Alberta.

Disclosure Issues in Oil Sands Development

Energy and Carbon Management

- Oil, natural gas and carbon pricing forecasts in relation to future oil sands production guidance
- Assumed growth and participation in carbon trading schemes and markets with Low Carbon Fuel Standards (LCFS)
- Investments in R&D and technologies to reduce carbon emissions, including renewable transportation fuels, carbon capture and sequestration (CCS) and related infrastructure
- Strategies and targets to reduce the CO₂ intensity and overall greenhouse gas emissions from operations and products

Water Use and Land Reclamation

- Water withdrawals and recycling rates from both surface and underground sources
- Freshwater/saline water recycling requirements for specific mining and in-situ projects
- Treatment of mining waste in tailing ponds and underground re-injection
- Strategies and targets to increase water storage and freshwater/saline water recycling
- Climate change considerations in future water management plans
- Human health and biodiversity impacts from cumulative oil sands development activities
- Plans to address new water use and land reclamation regulations (such as Directive 74)
- Effects of water treatment and land reclamation programs on operating costs and asset retirement obligations

Aboriginal Consultation

- Disclosure of any risks posed by current Aboriginal rights litigation
- Contact with Aboriginal communities and nature of any agreements in place
- Participation in multilateral initiatives, such as the All Parties Core Agreement
- Policies to guide future engagement, such as Free, Prior and Informed Consent
- Company resources made available for these activities and for educating employees about Aboriginal issues

List of Acronyms Used in this Report

ACES: American Competitiveness and Energy Security Act (2009)

AEO: Annual Energy Outlook

AOSP: Athabasca Oil Sands Partnership

ARO: asset retirement obligation

ARRA: American Recovery and Reinvestment Act (2009)

Boe: barrels of oil equivalent

Bbls: barrels of oil

Bbls/d: barrels of oil per day

CAD: Canadian dollar

CAPP: Canadian Association of Petroleum Producers

CERA: Cambridge Energy Research Associates

CCS: carbon capture and sequestration

CO₂: carbon dioxide

CO₂e: carbon dioxide equivalent

CT: consolidated tailings

EIA: Energy Information Administration (U.S.)

ERCB: Energy Resources Conservation Board (Alberta)

EISA: Energy Independence and Security Act (2007)

EROEI: energy return on energy invested

FPIC: free, prior and informed consent

FT: fine tailings

GHG: greenhouse gases

LCFS: low carbon fuel standard

Mbbl/d: million barrels of oil per day

Mcf: thousand cubic feet of natural gas

MFT: mature fine tailings

RFS: renewable fuel standard

SAGD: steam assisted gravity drainage

SCO: synthetic crude oil

SOR: steam-oil ratio

THAI: toe-to-heel air injection

Historical Perspective on Oil Sands Development

That this region is stored with a substance of great economic value is beyond all doubt, and, when the hour of development comes, it will, I believe, prove to be one of the wonders of Northern Canada.

— Charles Mari in 'Through the Mackenzie Basin', Year 1899

The first documented accounts of Canadian oil sands came well before the arrival of the Europeans, when the Cree and Dene native communities waterproofed canoes with the boiled tar substance. As Canada's great explorer of Scottish heritage Alexander Mackenzie journeyed from Canada's Atlantic East to the West Coast in 1778 in search of the Northwest Passage, he noted the "bituminous fountains" on the banks of the Athabasca River, which forms part of what is now known as the Mackenzie River system – the world's third largest watershed flowing into the Arctic Ocean. By the end of the 19th century, Ottawa became aware of the potential benefit of the oil sands resource, and signed a number of treaties with the Aboriginal communities to protect the land and secure the resource for the Crown Domain of the Dominion.



Source: various, assembled by RMG

The modern history of “Canada’s Great Reserve” is relatively short. It was not until the 1920s that Dr. Karl Clark, an Alberta chemist, filed a patent for the thermal extraction technology that is still used today. He managed to separate bitumen from oil sands through a hot-water process using his wife’s washing machine. The first commercial application was undertaken by J. Howard Pew, the U.S. industrialist and president of Sun Oil Company in 1965, when the first mine and upgrader (now known as Suncor) was built on the Athabasca River. Shortly after, in 1973, Syncrude – now a consortium of seven oil companies – followed suit. Following the oil crisis that year, the U.S. government unsuccessfully lobbied Canada to secure energy supplies on the North American continent by accelerating development through a \$20 billion investment program, funded by an international consortium and an \$8 billion U.S. government industrial assistance program. The second attempt to spur investment came in the early 1990s, when the National Oil Sands Task Force, a public private-partnership, was formed to attract \$25 billion in investment under the so-called Declaration of Opportunity.¹

Investments flowed into the area in the beginning of the 21st century, when oil prices began a steady climb. The third mine, the Albion Sands project operated by Shell, was brought into production in 2003. During 1997–2006, CAD \$59 billion was invested into the sector, and CAD \$80 billion in additional investment was planned for 2007–2010.² Following the oil price collapse in 2008, investment timelines were pushed back, and a majority of new projects were put on hold. Nevertheless, investment in the sector has picked up as the economy recovers and oil prices have rebounded to above \$80 per barrel.

Today, the Canadian oil sands are the world’s largest energy project. The industry has attracted investment from virtually every major domestic and international oil company, totaling \$200 billion in committed funds for current and proposed projects. Alberta is home to the world’s second largest hydrocarbon basin (after Saudi Arabia), containing 176 billion barrels of proved reserves of which 174 billion bbls is crude bitumen and 1.6 billion bbls is conventional crude oil. In 2008, the industry produced an average 1.3 million barrels per day (bbls/d), representing 59% of Canada’s and 1.5% of global oil production. Growth of the oil sands industry has enabled Canada to surpass Saudi Arabia as the United States’ largest oil supplier. Production is expected to peak anywhere between 2.3 million bbls/d and 6.3 million bbls/d in coming decades and potentially satisfy more than one third of projected U.S. oil demand by 2035.³

At the same time, oil sands projects in Alberta are Canada’s fastest growing source of greenhouse gas emissions. With continued expansion, oil sands are forecast to rise from 5% of the nation’s total CO₂ emissions to 15% by 2020, complicating Canada’s efforts to achieve GHG reduction goals. Since 2007, oil sands producers in Alberta have been subject to a provincial law that imposes a CAD \$15 per ton levy on CO₂ emissions. But the levy has had little demonstrable effect in altering oil sands production plans. Figure A illustrates the reserves as well as production guidance and CO₂ emission estimates of major oil sands companies through 2018.

Canada’s oil sands are the world’s largest energy project, with \$200 billion in funds committed.

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1. Dollars are expressed in U.S. currency unless otherwise noted, such as CAD \$ for Canadian dollars.
 2. “Oil Sands Economic Impacts Across Canada,” Canadian Association of Petroleum Producers (CAPP), April 2008.
 3. “Growth in the Canadian Oil Sands: Finding a New Balance,” Cambridge Energy Research Associates (CERA), March 2009. [The range is dependent on economic and policy scenarios outlined by CERA in this report.]

Figure A. Largest Oil Sands Companies

	Oil Sands Mining Reserves as % of Proved Reserves in 2007 ²	Projected Production in 2018 (boe/d)	Projected GHG Emissions in 2018 (million tonnes) ³	Projected Increase in Emissions 2018/2007 ⁴
Suncor ¹	56%	550,000	19.1	171%
Imperial	88%	510,000	20.9	143%
Petro-Canada	48%	190,000	6.9	112%
Husky	n/a	160,000	5.8	80%
StatoilHydro	n/a	200,000	7.3	47%
ConocoPhillips	2%	300,150	11.1	20%
Total SA (France)	n/a	259,500	8.1	14%
ExxonMobil	3%	508,800	19.3	14%
Occidental	n/a	31,000	1.0	10%
Marathon	26%	48,400	1.4	9%
BP	n/a	100,000	3.7	6%
Shell	9%	141,000	4.1	4%
Chevron	4%	48,400	1.4	2%
Murphy	32%	25,000	1.1	n/a
Sinopec	n/a	56,667	1.7	n/a
Group Total		3,047,250	109.9	

¹The list of largest integrated O&G companies can be expanded to include exploration & production companies COST, CNR, Nexen/OPTI, and Cenovus.

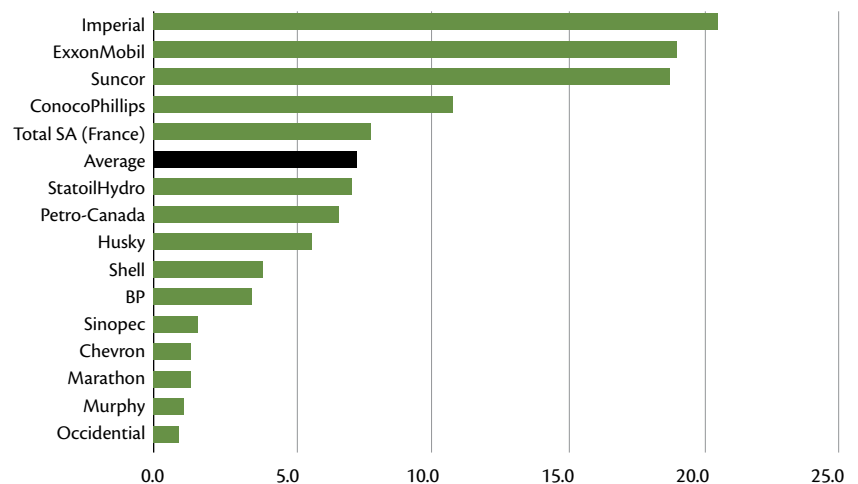
² This is mining oil sands reserves only. In-situ reserves are incorporated into the conventional oil reserve estimates. Several producers with substantial projects in the pipeline have not yet reached a stage in the project development when proved reserves are booked.

³2018 estimates are used, as this is when the Canadian federal government targets to start regulating emissions in oil sands projects, either by carbon sequestration or use offsets. Pembina Institute's estimates of projects' carbon emissions were applied.

⁴Projected 2018 GHG emissions from oil sands projects are compared to actual 2007 company-wide reported emissions

Projected Oil Sands GHG Emissions in 2018 (million tonnes)

Source: RMG, based on corporate disclosure



Oil Sands Production Primer

Canadian oil sands deposits are a mixture of sand (73%), clay and silt (13%), bitumen (10%), and water (4%). The ore lies above limestone and below the non-oil bearing layer of earth called overburden, which is covered by muskeg (an acidic type of soil common in boreal forests). The deposits are found primarily in Central Alberta in three main fields: Athabasca, Peace River and Cold Lake.

Bitumen is a heavy crude oil that cannot be recovered through a well in its natural state and hence needs enhanced recovery in the extraction process. The two main extraction methods are conventional surface mining and *in-situ* (Latin for 'in place') recovery using heat (steam). Approximately 20% of Alberta's oil sands are deposited close enough to the surface to be mined; the remaining 80% of the resource lies deeper underground and can only be recovered through in-situ processes. The mining reserves are concentrated in only 2.5% of the oil sands land area; in-situ reserves are spread over the remaining 97.5%. In 2008, 55% of Alberta's total 1.3 million bbls/d oil sands production came from mining, and 45% from in-situ projects.⁴

Open pit mining (see Figure C below) includes excavation of the ore, initial transport of the ore by diesel-powered trucks and secondary transport, or hydrotransport (ore dissolved in water) to the primary extraction facility. There the bitumen is separated from sand and other compounds, using Dr. Clark's hot water process, whereby the sand is essentially combined with hot water to become a slurry. As a result, the bitumen froth floats to the top of the separation vessel, where it is collected. The residual mixture then undergoes secondary recovery, whereby smaller quantities of bitumen are further separated from the slurry. While 50-80% of water is recycled in this operation, the remaining mixture of sand, clay and water, along with residual bitumen and other toxic compounds, is deposited into the waste containment areas, known as tailing ponds.

In-situ recovery can be achieved through a variety of technologies, including steam-assisted gravity drainage (SAGD), cyclic steam stimulation (CSS), vapor extraction (VAPEX), and toe-to-heel-air-injection (THAI). The most commonly used technique is SAGD, whereby a series of horizontal well pairs are drilled and steam is generated by a natural gas-fired furnace using water from nearby aquifers. The steam is then injected into the upper well, which heats up the ore and reduces the viscosity of

Figure B. Canadian Oil Sands Deposits

Source: created by Norman Einstein, May 2006



Figure C. Oil Sands Extraction Methods

Source: Canadian Centre for Energy Information



4. Government of Alberta, <http://www.energy.gov.ab.ca/OilSands/791.asp>

the bitumen, enabling it to gravitate towards the lower well and flow towards the surface. A large portion of the used water (70–90%) is recycled into the operation; however, the remaining amount remains underground, where it persists as a mixture of produced wastewater, clay and sand.

Bitumen extracted through either mining or in-situ methods is then piped to a so-called *upgrader*, which is essentially an oil processing facility, where it is further processed (i.e., upgraded) into the equivalent of conventional crude oil, or synthetic crude oil (SCO). The reason for this intermediary step is to reduce the high viscosity of the recovered bitumen, which cannot be handled by a conventional oil refinery. At the upgrader stage, bitumen – a complex, heavy hydrocarbon that is rich in carbon and poor in hydrogen – is coked (stripped of a portion of carbon), distilled (processed into various grades), catalytically converted (transformed into more valuable petroleum forms), and hydrotreated (stripped of a portion of sulfur and nitrogen molecules and enhanced with hydrogen).

The costs of existing extraction methods and upgrading processes are summarized in Figure D. The impacts of fluctuations in global commodity prices, cost of labor, financing costs and other factors affecting operating costs cause these estimates to change from year to year. This industry snapshot taken by the Canadian Energy Research Institute in 2008 shows representative costs for three forms of production plus upgrading in existing oil sands projects.⁵

Figure D. Operating Costs

Steam-assisted gravity drainage	CAD \$37.10/barrel
Cyclic steam stimulation	CAD \$41.94/barrel
Mining	CAD \$62.71/barrel
Upgrading	CAD \$38.75/barrel
SCO Integrated (Mining and Upgrading)	CAD \$98.16/barrel SCO
Source: CERI, 2008	

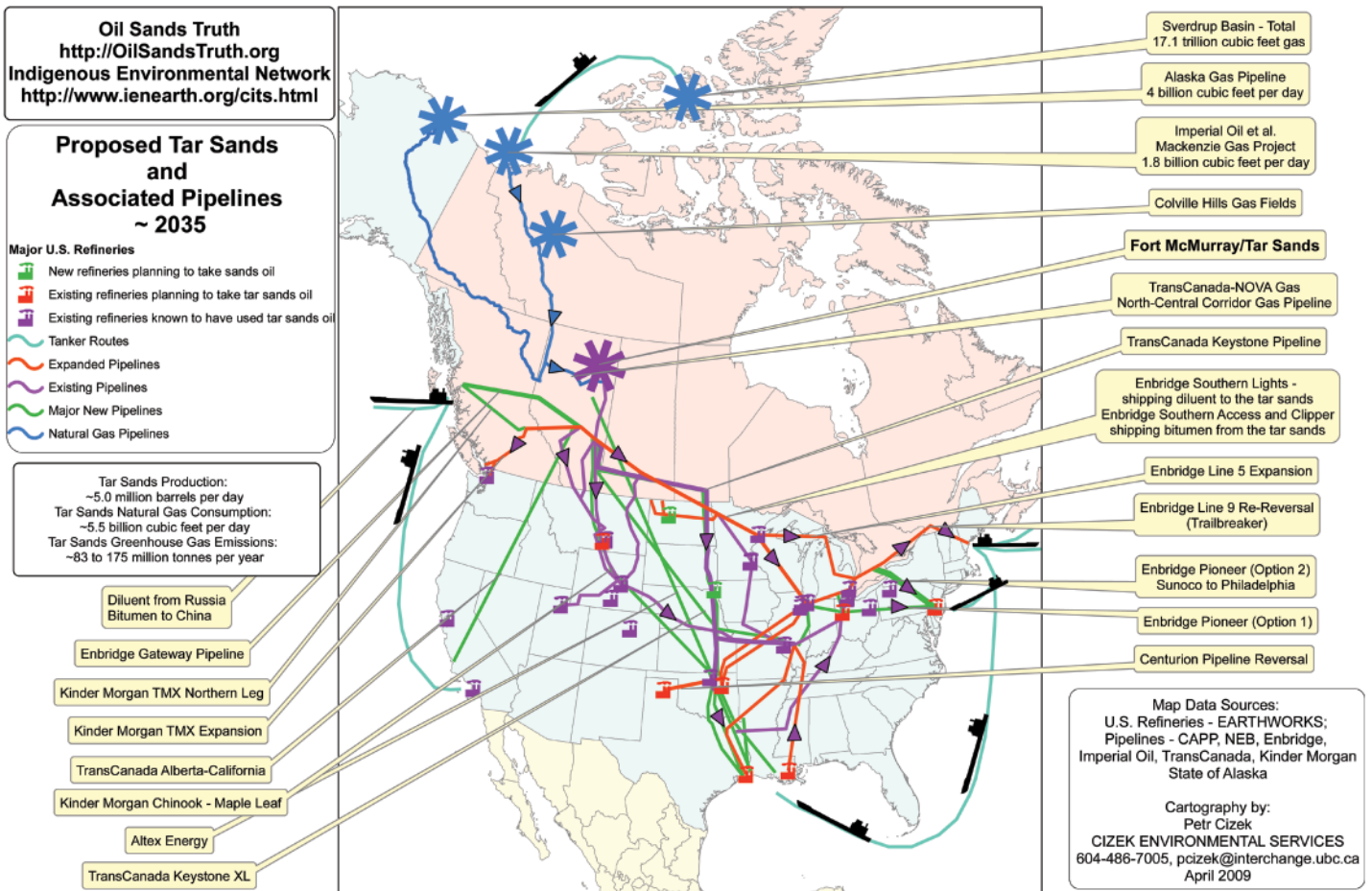
Once the bitumen has been upgraded into synthetic crude oil, it is piped to an oil refinery, where it is processed into final petroleum products, such as gasoline, diesel, jet fuel, petrochemicals, etc. Figure E exhibits a network of existing and proposed natural gas and oil pipelines in North America by 2035 to facilitate synthetic crude oil delivery. This includes U.S. refineries and proposed crude oil terminals on the Canadian West Coast in the Province of British Columbia for export to California, Asia and elsewhere. Successful completion of this pipeline infrastructure cannot be guaranteed, however, given many legal and regulatory challenges, including opposition by First Nations' and other Aboriginal communities to pipelines reaching the Canadian West Coast.⁶

5. Government of Alberta, <http://www.energy.gov.ab.ca/OilSands/791.asp>; Canadian Energy Research Institute (CERI), 2008 <http://www.ceri.ca/>

6. West Coast Environmental Law, www.wcel.org

Figure E. Proposed Pipelines for Natural Gas Supply to the Oil Sands Industry

Source: Oil Sands Truth, and Indigenous Environmental Network



1. Macroeconomics of Oil Sands Production

Analyzing the prospects for oil sands production requires a long look into the future. Site development typically requires lead times of five to eight years before the oil starts to flow. Most projects are assumed to have operating lives extending up to 40 years or more. To capture relevant project dynamics, our analysis extends up to the year 2030.

Many issues will influence future oil sands production volumes. These include:

- Global factors—oil price and supply, GDP demand growth and technology advances
- National factors in the U.S. and Canada—carbon and energy efficiency regulations, vehicle fuel economy standards and energy security
- State and provincial factors—renewable portfolio standards and low carbon fuel standards

This chapter assesses each of these influences and uses a multi-factor energy forecasting model from the U.S. Energy Information Administration to make projections of the range in possible oil sands production growth through 2030.

1.1 Price of Oil and Oil Sands Production

The financial success of Canadian oil sands production hinges on maintaining a sufficient global floor price for oil. Because oil sands production involves a number of additional energy-intensive steps to create synthetic crude oil, it is placed at an immediate cost disadvantage relative to conventional oil. Estimates of the required floor price to recover the costs of new oil sands in-situ projects range from \$65 to \$95 per barrel.⁷ This is significantly higher than the cost of most new oil projects involving conventional crude. The collapse in global oil prices in the second half of 2008, with prices dipping below \$40 per barrel by the end of the year, demonstrated how sensitive oil sands investment is to the macro oil price environment. More than 20 planned large-scale upstream oil and gas projects, involving around 2 mbbbl/d of oil production capacity, were deferred indefinitely or canceled during the oil price drop; 85% of these were Canadian oil sands projects.⁸

Now that global oil prices have regained levels above \$80 per barrel, prospects for oil sands producers appear brighter. However, oil sands production is also vulnerable to potential upper limits on global oil prices as well. As demonstrated by the price spike to \$147 per barrel in July 2008, high oil prices can put a drag on economic growth and force the global economy into recession. This in turn leads to a decline in commodity prices, potentially below the level where oil sands are profitable.⁹ High oil

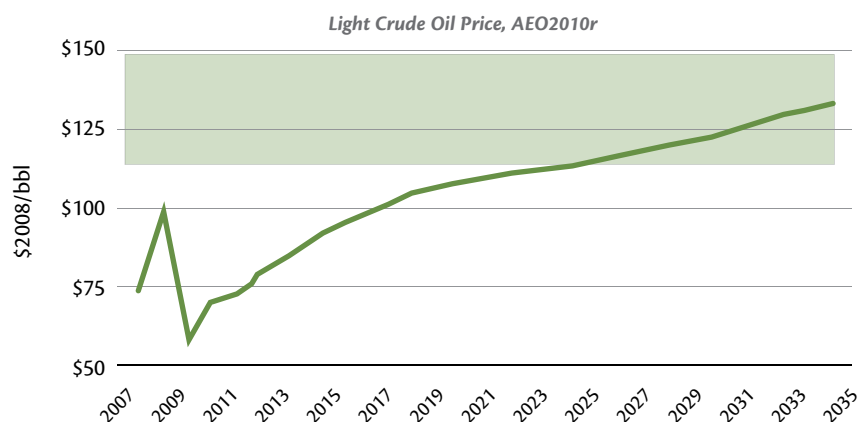
7. Total S.A. (France), 2008; “The Peak Oil Market: Price dynamics at the end of the oil age,” Deutsche Bank, Oct. 4, 2009; and “Canadian oil sands fieldtrip 2009: Key takeaways,” Goldman Sachs, Nov. 19, 2009.

8. “The Peak Oil Market: Price dynamics at the end of the oil age,” Deutsche Bank, Oct. 4, 2009;

9. Marc Brammer and Yulia Reuter, “The Viability of Non-Conventional Oil Development,” Innovest Strategic Value Advisors, Mar. 2009.

Figure F. Crude Oil Price Projections through 2035

Source: U.S. Energy Information Administration (EIA), 2010 Annual Energy Outlook (AEO)



prices also stimulate investments in energy efficiency and alternative energy sources that further erode the demand and supply base for oil.

Generally, recessionary repercussions of a high oil price in the United States—the largest market for oil sands production—are witnessed either at high price levels, when domestic energy costs reach 4% of gross domestic product, or upon a rapid price increase of 50% year over year.¹⁰ Cambridge Energy Research Associates (CERA) produced a study in 2008 in which it identified an oil price “break-point” of \$120 to \$150 per barrel. As global oil prices approach these levels, various demand-destroying factors come into play, namely energy efficiency measures, regulatory policy changes, innovation, alternative transportation fuels and heightened attention to environmental concerns, which effectively limit any further upward pricing pressure (see Figure G).¹¹

Another consideration is future demand for oil itself. Deutsche Bank has forecast that demand for oil will peak globally by around 2016.¹² CERA believes that oil demand has already peaked in the developed world.¹³ Such forecasts add to the argument that oil producers may have difficulty sustaining demand at prices above \$150 per barrel, and perhaps even at considerably lower levels.

For oil sands producers, this means that there is a relatively narrow financial window in which to operate. They need oil prices to stay high enough to make a profit—in excess of \$65-\$95 per barrel—but not get so high as to reduce oil demand or stimulate substitution by competing fuels. There is reason to believe that the future floor price for profitable oil sands production will be significantly higher than at present. As the world comes out of recession and the input price of commodities such as steel begins to rise, the break-even price for new oil sands projects could approach levels seen several years ago, when by some estimates it exceeded

Oil sands operate in a narrow window of financial opportunity.

10. “Oil: What Price Can America Afford?” Douglas-Westwood Energy Business Analysts, June 2009.

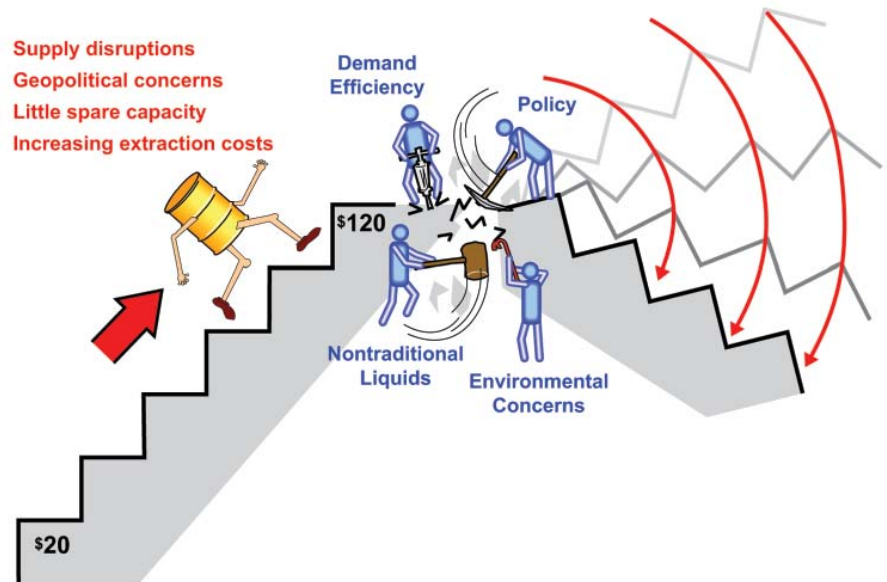
11. “Break Point Revisited: CERA’s \$120–\$150 Oil Scenario,” CERA Special Report, 2008.

12. “Deutsche: the end is nigh for the Age of Oil,” Financial Times, 2009.

13. “Peak Oil Demand in the Developed World: It’s Here,” CERA, Sept. 29, 2009.

Figure G. Oil Price Break Point

Source: CERA, "Break Point Revisited," 2008



\$100/barrel.¹⁴ In addition, other factors such as carbon pricing and mounting environmental compliance costs may cause the effective floor price of oil sands production to rise, even as demand-limiting factors cause the ceiling price for global oil production to fall. As a result, oil sands' already narrow window of opportunity may shrink even further, especially if the United States remains its prime export market. Should oil sands expand into growing Asian markets, which appears far from certain at this point, the dynamics described here could change.

1.2 Price of Natural Gas and Oil Sands Production

The price of oil is not the only macroeconomic consideration in converting oil sands into synthetic crude. Natural gas is intensively used to power oil sands mining extraction facilities and especially for in-situ steam-generators. In fact, oil sands extraction has a comparatively low energy return on energy invested (EROEI) of 7:1, meaning it takes one unit of energy (primarily in the form of natural gas or diesel fuel) to extract seven units of energy from bitumen. The energy economics are further reduced to EROEI of 3:1 when the bitumen is upgraded and refined. By comparison, conventional oil has an EROEI average of 22:1, conventional natural gas (21:1), wind energy (18:1), geothermal (16:1), and sugarcane ethanol (8:1).¹⁵

At present, the oil sands industry consumes 4% of the natural gas produced in the Canadian Sedimentary Basin. This figure is expected to triple between 2005 and 2015, to 2.3 billion cubic feet of gas per day (ft³/d).¹⁶

Regulatory efforts to address climate change and other pollution problems are expected to further increase demand for natural gas in the transportation and

14. Scott Haggett, "UPDATE 1 — UBS says new oil sands projects need pricey crude," Reuters, Sept. 19, 2008.

15. Peter Terzakian, "The End of Energy Obesity," John Wiley & Sons, Inc., 2009, p.111.

16. Statistics by Energy and Utilities Board, published by The Center for Energy, 2005, <http://www.centreforenergy.com/silos/NaturalGasPrices/NG-MarketDynamics.asp>

electric power sectors. Natural gas is the cleanest-burning of the fossil fuels and has slightly less than half the carbon content of coal and only two thirds that of oil. These changing market dynamics will spur more use of natural gas in heavy duty vehicles like trucks and buses that connect to central refueling centers. In addition, gas-fired power generation will also grow in place of more carbon-intensive options like coal. Combined cycle gas turbines (CCGT) that already represent a substantial portion of the U.S. generating fleet will provide more baseload power generation, meaning they will run constantly instead of just during high-demand periods.

Greater access to shale gas deposits in the United States will help spur this move towards natural gas. The U.S. Energy Information Administration projects that anywhere from 42 to 112 gigawatts (GW) of new gas-fired power generation capacity may be added in the United States between 2007 and 2030, with the most likely number estimated to be around 90–100 GW. By some estimates the generating costs of CCGT could become fully competitive with coal for base-load power generation when CO₂ allowance prices reach \$13.70/ton in a fully auctioned cap and trade market.¹⁷ This price is at the low end of the range for estimated carbon credits, making natural gas a go-to option for power producers seeking to reduce their carbon footprints. Such competing demands for natural gas may leave oil sands producers searching for other energy input options that better serve their needs. One proposed solution is to gasify petroleum coke, a by-product of bitumen extraction process, which would be available on-site and avoid the logistical difficulties associated with natural gas delivery. However, this process poses significant environmental challenges and increases carbon compliance costs due to the high-carbon nature of the gasification process. Toe-to-heel air injection (THAI) is another option that uses fire in place of steam as an underground heat source to draw out the bitumen. Goldman Sachs recently estimated that successful use of the THAI process could yield savings equal to \$20 per barrel if it reduced SCO's natural gas requirements to zero. However, use of the THAI process is very limited at present, with one project by Petrobank producing 10,000 bbl/d.¹⁸

Nuclear power is another possible alternative to natural gas for oil sands production. But in order to satisfy the oil sands industry's forecasted demand for power generation as production grows, at least 20 new nuclear power plants would need to be constructed on oil sand leases in Alberta, which could prove to be politically contentious.¹⁹ No oil sands producers at present have plans to make use of nuclear power. However, Total SA reported in September 2005 that it was considering building a nuclear plant to support its oil sands development in Alberta.²⁰

1.3 Canadian Oil Sands and the U.S. Petroleum Market

The United States produced 10% of the world's petroleum in 2008, but consumed 23% of the global supply. According to the U.S. Energy Information Administration (EIA), transportation accounts for roughly two-thirds of U.S. petroleum consumption, with gasoline representing almost 50% of the total volume of U.S.

Oil sands are a large and growing consumer of clean-burning natural gas.

17. Eric Kane and Marc Brammer, "Dong Energy: Risk Assessment for Shareholders of the Proposed 1,500 MW Coal-Fired Plant in Greifswald, Germany," Innovest, Nov. 2008.

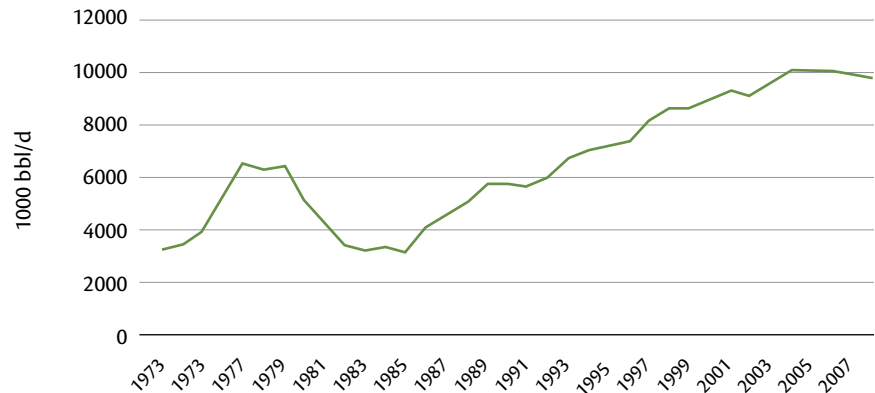
18. "Canadian oil sands fieldtrip 2009: Key takeaways," Goldman Sachs, Nov. 19, 2009.

19. Dan Woynillowicz, "Oil Sands Fever: Environmental Implications of Canada's Oil Sands Rush," The Pembina Institute, November 2005.

20. David Gauthier-Villars, "Total may use atomic power at oil sands project," Wall Street Journal Europe, Sept. 2005.

Figure H. U.S. Crude Oil Imports, 1973–2008

Source: U.S. Energy Information Administration (EIA)



petroleum products. This creates a key export market for foreign oil suppliers, including Canadian oil sands producers who send most of their output to this vital market for transportation fuels.²¹

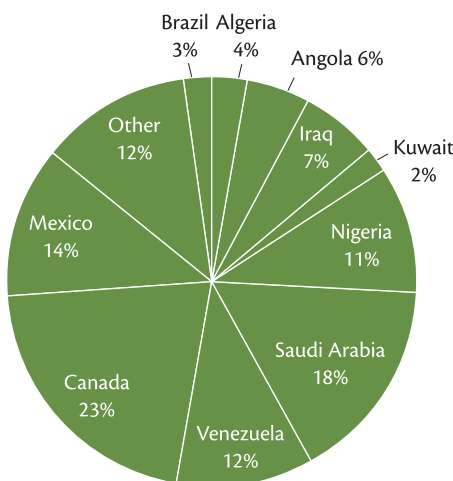
In 2008, the Canadian oil sands industry produced an average of 1.21 mbbbl/d, representing 45% of total Canadian oil production and 1.5% of global oil production. Altogether, more than two-thirds of Canadian oil production was exported to the U.S. market in 2008, providing 1.67 mbbbl/d, equal to 9% of total U.S. consumption. The majority of future Canadian supply to the United States is expected to come from synthetic crude originating in Alberta, where oil sands production may double over the next decade and could possibly more than triple by 2030. In the United States, oil sands are primarily concentrated in eastern Utah, mostly on public lands where some development may be restricted. The estimated in-place reserve is 12 to 19 billion barrels, only about 7–11% as much as in Alberta.

Between the early 1980s and 2005, crude oil imports rose steadily in the United States, but have since leveled off. Many energy experts believe U.S. demand for imported crude oil has peaked. At the same time, however, U.S. oil imports from Canada are steadily rising. In 2004, Canadian crude surpassed imports from Saudi Arabia, Venezuela and Mexico, and now represents 23% of total U.S. imports. The EIA forecasts that U.S. imports of Canadian oil will remain at 22% of total imports through 2035.

Overall, the EIA estimates that total U.S. consumption of liquid fuels, including both fossil liquids and biofuels, will grow from 19 million barrels per day in 2008 to 22 million barrels per day in 2035. Biofuels are expected to supply all of the growth in the liquid fuels supply, with the contribution from petroleum-based liquids essentially remaining flat. The EIA also projects that U.S. reliance on imported liquid fuels will fall from 57% of total consumption in 2008 to 45% by 2035.²² This decline would mainly result from fuel-efficiency gains that limit U.S. demand growth in the transportation sector as well as increased domestic production of biofuels.

Figure I. Top U.S. Oil Suppliers, 2008

Source: U.S. EIA

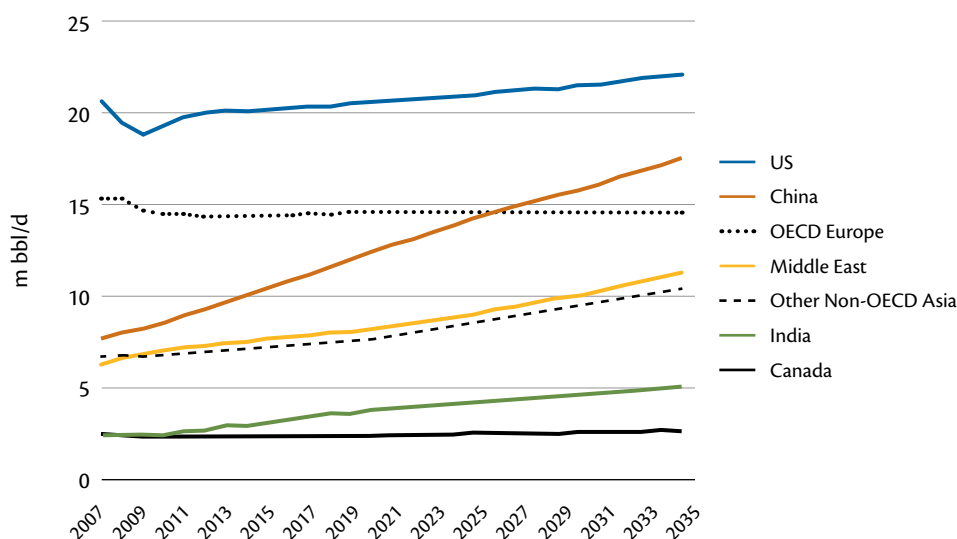


21. Secondary markets include heating oil and aviation fuel.

22. EIA AEO 2010 reference case

Figure J. Global Petroleum Consumption: 2007–2035

Source: U.S. EIA, 2010 AEO



In 2008, 95% of U.S. transportation energy came from petroleum and only 3% came from renewables.²³ The policy goal of the Obama administration is to accelerate a move toward renewable fuels and energy efficiency. Nevertheless, by 2035, the EIA projects that conventional crude oil will remain the dominant source of supply on global markets, representing 87% of crude oil production, with unconventional sources like oil sands making up approximately 13% of the supply.

Oil sands are the fastest-growing source of US oil imports.

Looking forward, one key question facing Canadian oil sands producers is whether they will seek to develop other major export markets beyond the United States. The International Energy Agency's 2009 *World Energy Outlook* projects that primary energy demand will grow by 40% globally through 2030, with global oil demand rising by 24% to 105 m bbl/d. While the United States is expected to remain the largest petroleum consumer over this period, Chinese consumption is expected to overtake the U.S. by 2045. Other growing petroleum markets include the Middle East, India and non-OECD Asia. Favored oil suppliers for these regions include members of the Organization of Petroleum Exporting Countries (OPEC) and Russia, which have production in close proximity to these growing markets.

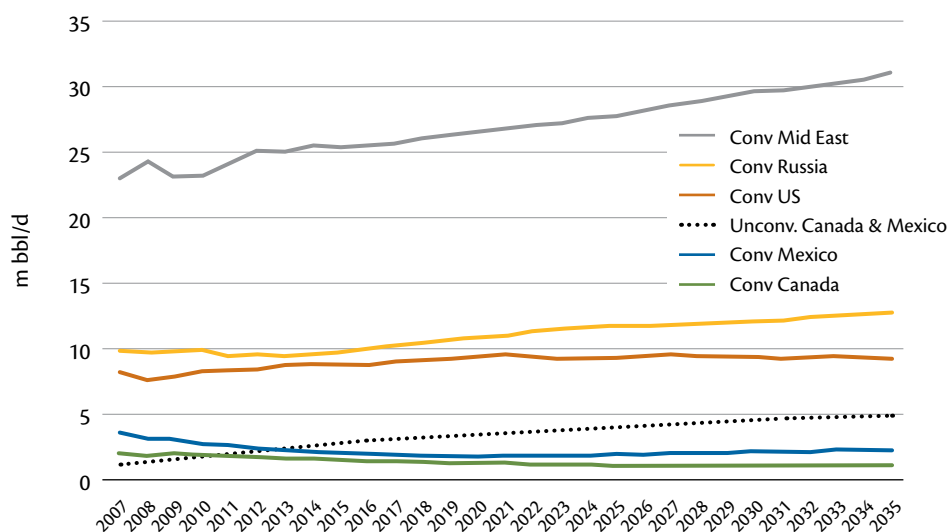
Many oil-importing countries will look increasingly to Saudi Arabia and Canada for supply, since together they account for 33% of the world's proven petroleum reserves as of 2010.²⁴ But for Canadian oil sands producers to serve these growing export markets, new pipelines would have to extend from Alberta to Canada's port cities, and new refineries would have to be built near these cities or in countries importing the fuel. For this to happen, oil sands producers will have to overcome considerable environmental opposition and legal challenges, especially from First Nations communities who have significant rights and protections under the Canadian Constitution. Enbridge's proposed Gateway pipeline to Canada's west

23. EIA Annual Energy Review 2009, U.S. Primary Energy Consumption by Source and Sector, 2008, http://www.eia.doe.gov/aer/pecss_diagram.html

24. EIA Country Analysis Briefs: Iran Oil, <http://www.eia.doe.gov/cabs/iran/oil.html>

Figure K. Petroleum Production by Region: 2007–2035

Source: U.S. EIA, 2010 AEO



The US is expected to remain the dominant export market for Alberta’s oil sands.

coast would cross the territories of 42 separate First Nations, many of whom have expressed significant opposition to the project. Several extraction companies have been denied permits or put projects on hold because they failed to gain consent from First Nations in the same region of British Columbia where the Gateway pipeline would pass. In addition, coastal First Nations have objected to the pipeline, which would bring oil tankers through their territories in order to ship the bitumen to market. In March 2010, nine Coastal First Nations cited concerns over the lasting and devastating effects of a possible oil spill in explaining their opposition to the Gateway pipeline, and said that the Athabasca Chipewyan Cree First Nation located near Alberta’s oil sands backed their declaration.²⁵

Given these roadblocks to tapping other foreign markets, for the foreseeable future output from oil sands will remain dependent on U.S. petroleum demand and global market conditions, including potential regulations on the carbon content of fuels. As a high cost source of supply, the oil sands will require a relatively high oil price in order to justify continued investment in production growth. The U.S. Energy Information Administration anticipates a steady rise in oil prices as the global economy recovers—with the price per barrel expected to reach \$133 by 2035 in constant 2009 dollars. This report assumes that global oil prices will remain high enough to keep oil sands production profitable, but not rise to the point where other demand-curtailling factors would come into play. This report also assumes that the United States will remain the prime market that will determine the scale of future Canadian oil sands production. These are critical assumptions, since lower global oil prices could depress Canadian oil sands production, while sustained higher prices and/or the opening of new export markets possibly could stimulate oil sands production beyond the levels modeled here.

25. “First Nations Say They Will Not Allow Pipelines and Oil Tankers Carrying Alberta’s Tar Sands Oil in British Columbia,” Canada Newswire, Mar. 23, 2010.

1.4 Oil Demand Constraints in the United States

The remainder of this chapter explores how current and planned U.S. regulations could affect future oil demand, and its possible effects on imports of Canadian oil sands. Reference scenarios developed by the Canadian Association of Petroleum Producers (CAPP) are compared against the oil demand-limiting effects of:

- the U.S. American Recovery and Reinvestment Act (ARRA)
- transportation fuel demand restrictions for U.S. federal government agencies, including specifically a synfuel ban
- vehicle fuel efficiency as defined by Corporate Average Fuel Economy (CAFE) standards
- a federal climate change bill to reduce greenhouse gas emissions, and
- Low Carbon Fuel Standards (LCFS) as defined in state and federal regulatory proposals

Of these factors, our modeling results show that LCFS has the greatest potential by far to constrain future oil sands production.

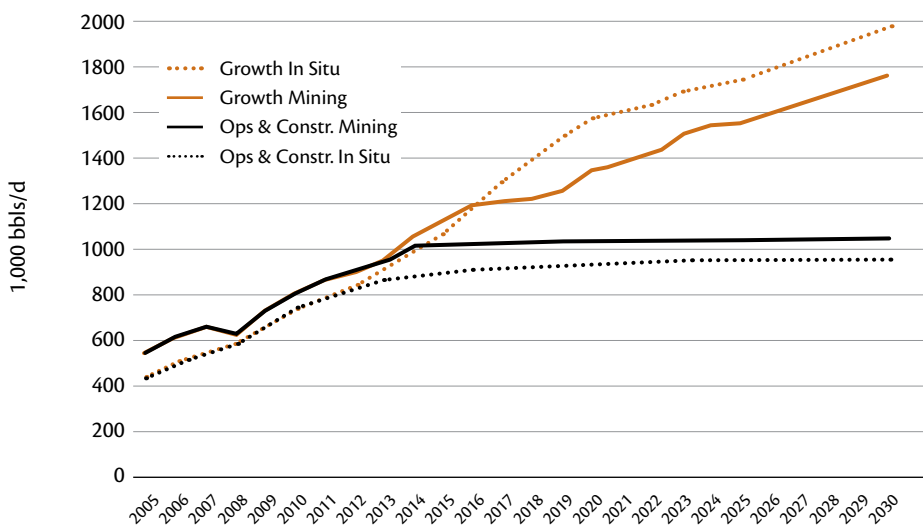
Reference Scenario for Canadian Oil Sands Production

The Canadian Association of Petroleum Producers (CAPP) issued results of a survey of Canadian oil sands producers in June 2009.²⁶ The survey presents two projections of growth in oil sands production through 2025:

- a “Growth Case” that assumes a favorable investment climate for additional capacity growth
- an “Operating & Construction Case” that forecasts production utilizing only current operations and capacity under construction

Figure L. Oil Sands Production Projections: CAPP

Source: Canadian Association of Petroleum Producers (CAPP)



26. “Crude Oil: Forecast, Markets & Pipeline Expansions,” Canadian Association of Petroleum Producers (CAPP), 2009.

In the Growth Case, conventional oil production in Canada falls from 41% to only 15% of total supply by 2025, while oil sands production increases from 59% to 85%.²⁷ The scenarios presented in this report extend the forecast to 2030, using the same growth rate projections as presented in the CAPP survey for 2020 to 2025. This makes oil sands the increasingly dominant source of Canadian oil supply.

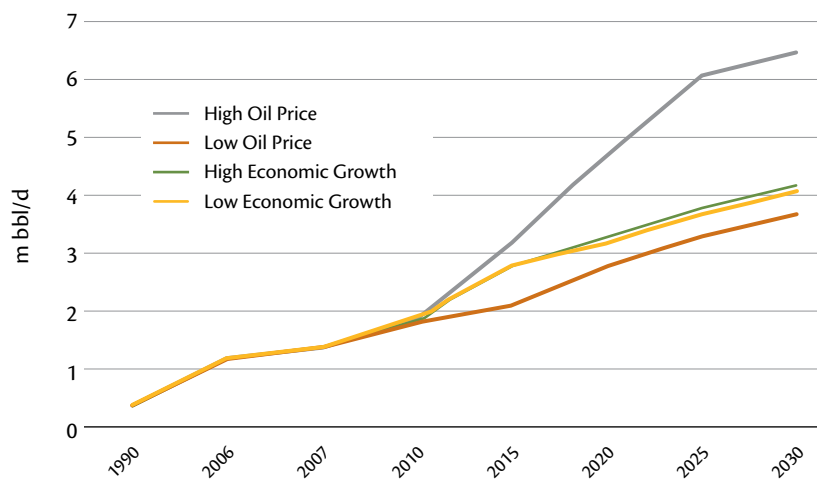
By 2030, in-situ oil sands production is projected to reach 2.0 mbb/d in the Growth scenario, and mining oil sands production is projected to reach 1.7 mbb/d, for a total of 3.7 mbb/d of production. This compares with 1.21 mbb/d of total production in 2008, with more than half of the production coming from mining.

In the Operating & Construction scenario, oil sands production levels off at about 2.0 mbb/d in 2015 and maintains that level through 2030. Mining still holds a slight edge in total production volume compared to in-situ.

Oil sands production could more than triple by 2030.

Figure M. Oil Sands Production Projections: U.S. EIA

Source: U.S. EIA, 2010 AEO

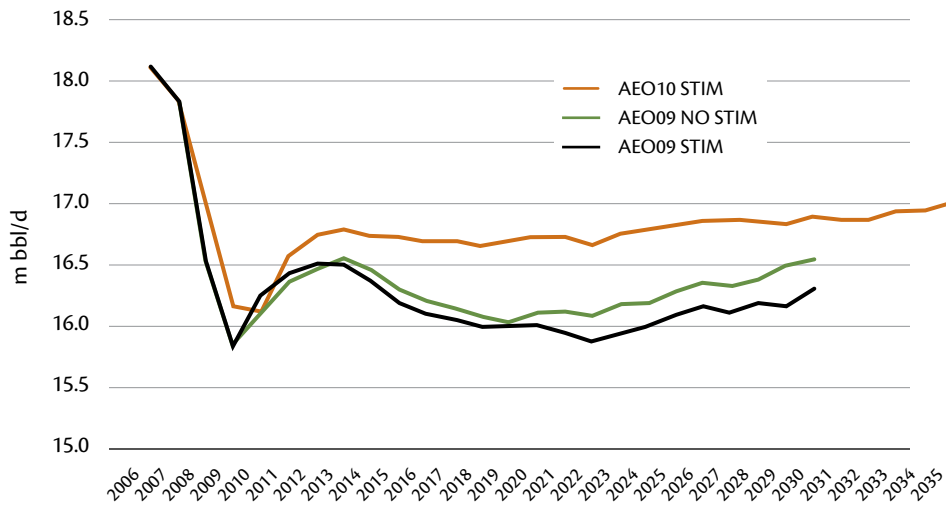


It is worth noting that some forecasts of Canadian oil sands production are more bullish than the projections presented here. In the EIA's 2009 *International Energy Outlook* (IEO), oil sands production is projected to reach as high as 6.5 mbb/d by 2030, if oil prices climb to \$200 per barrel (in 2009 dollars). Under the EIA's reference case, oil sands production reaches 4.2 mbb/d by 2030, with oil at \$130 per barrel. (Note the significantly greater effect of oil price variance on oil sands output compared with economic growth rates projected by the EIA.) Accordingly, the Growth Scenario in this report more closely resembles EIA's low oil price projection, where oil sands production achieves 3.7 mbb/d of production by 2030, with oil prices at only \$50 per barrel. We believe the low oil price scenario put forth by EIA to be unlikely, given the EIA's 2010 AEO oil price projections. As a result, the modeling assumptions used in this report—and CAPP Growth forecast on which they are based—may be viewed as conservative in relation to the EIA reference case, which forecasts an additional 500,000 bbl/d of production by 2030, to 4.2 mbb/d, with oil at \$130 per barrel.

27. This breakdown excludes Canadian pentanes and condensate production.

Figure N. U.S. Oil Demand Projections under ARRA

Source: U.S. EIA, 2009 AEO and 2010 AEO



ARRA Effect

The economic recession that struck the United States in late 2007, followed by oil prices reaching a peak of \$147 per barrel in July 2008, has resulted in a substantial drop in U.S. oil consumption—falling from 18.2 m bbl/d in 2006 to just 15.8 m bbl/d in 2009, a nearly 13% decline. The American Recovery and Reinvestment Act (ARRA) passed by Congress in February 2009 includes measures both to stimulate the economy (and hence energy demand) in the near term, while also promoting energy conservation and greater use of alternative fuels over the longer term. These domestic measures in turn have implications for the CAPP forecast, given that more than two-thirds of Canadian oil is exported to the U.S. market. Potential demand-limiting measures of ARRA include:

- weatherization and assisted housing
- energy efficiency and conservation block grant programs
- support for state energy programs
- tax credits for plug-in hybrid and electric vehicles and for renewable electricity generation; loan guarantees for renewables and biofuels
- support for carbon capture and storage (CCS), and
- smart grid expenditures

Our review of ARRA finds only a minimal net impact on oil sands production, reducing the CAPP Growth forecast by 0.5-2.0% over the measurement period. (In Figure N, this is depicted as the difference between the AEO09 NO STIM and AEO09 STIM chart lines.) This slight change is to be expected as many of the energy provisions of ARRA address the building sector rather than the transportation sector. EIA has since updated its forecast, taking account of the ARRA stimulus package (depicted as AEO10 STIM in the chart). The new forecast projects a more rapid and smoother economic recovery whereby the stimulus does more to spur energy demand than the energy conservation measures do to constrain future petroleum demand. The updated EIA projections are more in line with the CAPP Growth scenario.

Other Federal Demand-Reducing Measures for Transportation Fuels

Several additional federal regulations specifically target demand reductions for liquid fuels in the U.S. transportation sector. These include Corporate Average Fuel Economy (CAFE) standards, proposed support for electric vehicles under H.R. 2454 American Clean Energy and Security Act (ACES), regulations reducing Federal agency demand for high-carbon transportation fuels, and Low Carbon Fuel Standards (LCFS) at the state, regional and federal level. This section evaluates the impact of these measures on the market for oil sands oil in the U.S. market.

Mandates to Reduce Demand for Transportation Fuels

In April 2010, the Obama administration approved new CAFE and greenhouse gas (GHG) emission standards developed jointly by the EPA and the National Highway Transportation Safety Administration. By 2016, new passenger cars will need to reach 39 miles per gallon (mpg), and light trucks 30 mpg, with standards developed for each vehicle class size, equal to 35.6 mpg for the 2016 combined new vehicles fleet. (The current combined CAFE standard is slightly more than 25 mpg.) The program also imposes a fleet wide limit of 250 grams CO₂ equivalent by 2016, a 26% improvement over the average for 2009 model year light-duty vehicles. This federal rule supersedes a California law that would have taken effect in 2012, with similar GHG emission targets. It is projected to save 1.8 billion barrels of oil over the life of cars and trucks sold between the 2012-16 model years as a result new vehicles' improved fuel efficiency. The federal rule is more ambitious than an earlier target of not less than 35 mpg for the combined fleet of cars and light trucks by model year 2020, approved by Congress as part of the 2007 Energy Independence and Security Act (EISA).

Many factors influence the effect of CAFE standards on overall demand for transportation fuels. These include:

- The size and composition of the U.S. transportation fleet (currently 90% light-duty passenger vehicles, 2% commercial light trucks, and 8% freight trucks; commercial and freight trucks are not subject to the CAFE standard)
- Annual vehicle miles traveled (VMT)—a reflection of both U.S. fleet composition and driving behavior
- Mileage efficiency achieved (CAFE) in each vehicle category
- The average age of vehicles on the road relative to new vehicles sold (i.e., fleet turnover rate)

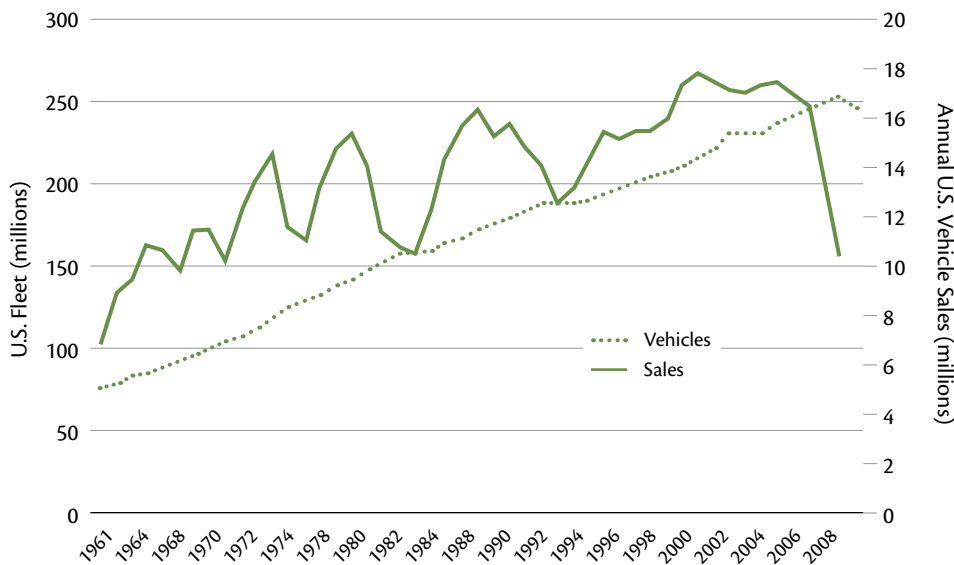
Gasoline consumption as a percentage of total U.S. petroleum consumption has been declining at about 0.2% per year since 1949, when EIA records began. For our modeling purposes, we assume that transportation will continue to account for 65% of U.S. petroleum consumption through 2030. However, recent trends suggest that transportation demand may decline to 59% of petroleum consumption as renewable fuels and efficiency measures offset some of this market.

Key to this forecast is a projection of the size of the U.S. motor vehicle fleet. In 2009, the U.S. fleet shrank for the first time, dropping to 246 million vehicles from a peak of 250 million in 2008, as vehicle scrappage rates (14 million cars) exceeded new

vehicle sales.²⁸ This is a reflection of the recent economic recession and the steep increase in gasoline prices in 2008. In 2009, 10.4 million cars and trucks were sold in the U.S., down from 13.5 million in 2008 and a peak of 17.8 million in 2000.²⁹ The last time vehicle sales were this low was in 1980. Vehicle sales are expected to revive as the economy improves and gasoline prices remain below the peak of \$4.10 per gallon reached in July 2008. Nevertheless, market saturation, energy pricing trends, environmental concerns and a generational shift away from cars could extend this overall decline.

Figure O. U.S. Vehicle Sales and Fleet Size: 1961–2009

Source: U.S. National Highway Transportation Safety Administration



Our model assumes a 1% annual reduction in annual U.S. vehicle sales through 2030. At the same time, we project that the entire U.S. fleet (light duty, commercial truck and freight), weighted by the percent miles traveled in each category, will achieve a combined 33 mpg by 2020 and 35 mpg by 2030. This equates to an annual fuel efficiency increase of 1.6% for the entire U.S. ground transportation fleet. However, this may be largely offset by a projected 1.5% average annual increase in total U.S. fleet vehicle miles traveled (VMT). Under these assumptions, petroleum consumption in the transportation sector would remain largely constant, with increases in VMT offsetting most of the fuel economy gains and reductions in the U.S. vehicle fleet.

28. "U.S. Car Fleet Shrank by Four Million in 2009 — After a Century of Growth, U.S. Fleet Entering an Era of Decline," Earth Policy Institute, Jan. 6, 2010.

29. "U.S. Car and Truck Sales, 1931–2008," Ward's Automotive Group, "WARDS U.S. Light Vehicle Sales by Company," Ward's Automotive Group, Jan. 5, 2010.

Mandates to Decrease Federal Government Oil Consumption

Section 526 of the 2007 Energy Independence and Security Act (EISA) prohibits U.S. Federal agencies from procuring unconventional transportation fuels—a.k.a. “synfuels”—unless they have life cycle GHG emissions that are less than those from conventional petroleum sources. Synfuels, in general, refer to fuels processed from bituminous sands, oil shale, coal gas, and biomass. Historically, the Federal government has accounted for 2.52% of total annual U.S. petroleum consumption, with the majority coming from the Defense Department and military operations. Accordingly, application of Section 526 could eliminate a small portion of the Canadian oil sands market that otherwise would be available to supply the U.S. Federal government.

Furthermore, an Executive Order by the Obama administration in October 2009, titled “Federal Leadership in Environmental, Energy and Economic Performance,” requires a 30% reduction in Federal agency vehicle fleet petroleum use by 2020, equal to a 3% annual reduction starting in fiscal year 2010.³⁰ This order will place more downward pressure on petroleum demand from the U.S. Government, beyond the synfuel restrictions imposed by Section 526 of EISA.

The climate bill passed by the U.S. House of Representatives in June 2009, known as the American Clean Energy and Security Act (ACES), also provides strong support for the development of electric vehicle infrastructure and manufacturing. This includes the allocation of emission allowances for investment in clean vehicles and further incentives in the form of loans for advanced technology vehicle manufacturing. Moreover, in Sections 121 to 130, ACES provides further development of alternative fuel vehicles after 2016. Additionally, Section 130A provides research incentives for greater use of natural gas in transportation to decrease GHG emissions. Each of these measures, if adopted in final climate legislation, would further reduce U.S. demand for liquid petroleum fuels in the transportation sector.

To assess the impact of such legislation and the more stringent CAFE standard of 35 mpg by 2016 issued by the Obama administration, the EIA has conducted an analysis in response to a request from U.S. Representatives Henry Waxman (D-Calif.) and Edward Markey (D-Mass.), the prime sponsors of the House ACES bill. The EIA analysis also takes account of the ARRA legislation passed by Congress in February 2009. The results of this analysis have been included in our model to account for the effects on the CAPP Growth forecast for oil sands production through 2030, and are shown in Figure P. The combined effect of the accelerated CAFE standard, support for clean vehicle development, and other provisions of a potential climate and energy bill approved by Congress would put further downward pressure on U.S. petroleum demand, which in turn could reduce the CAPP projections. However, the net effect is relatively modest, with the reduced U.S. demand slowing oil sands production to an annual rate of 5.0% through 2030 rather than at a rate of 5.6% under the CAPP Growth forecast. This means that by 2030, oil sands production would reach only 3.5 mbbbl/d, rather than 3.7 mbbbl/d under the CAPP Growth forecast, a reduction of 7%.

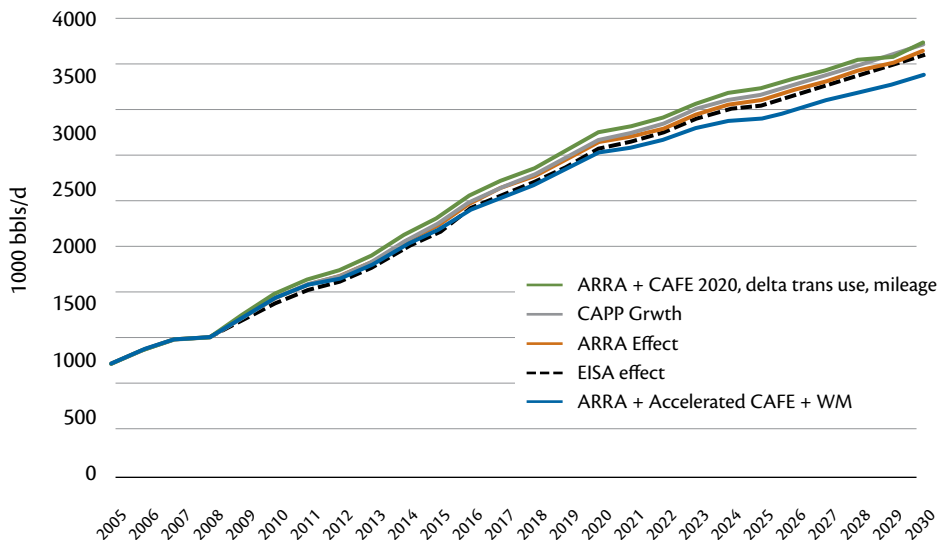
As discussed in the next section, the imposition of Low Carbon Fuel Standards could have a much greater impact on future oil sands production.

Federal programs to reduce fuel and greenhouse gas emissions may have only a modest effect in reducing demand for oil sands; Low Carbon Fuel Standards could have a much greater impact.

30. “Federal Leadership in Environmental, Energy and Economic Performance,” The White House, Oct. 5, 2009. http://www.whitehouse.gov/assets/documents/2009fedleader_eo_rel.pdf
“President Obama Signs an Executive Order Focused on Leadership in Environmental, Energy and Economic Performance,” The White House, Oct. 5, 2009. http://www.whitehouse.gov/the_press_office/President-Obama-signs-an-Executive-Order-Focused-on-Federal-Leadership-in-Environmental-Energy-and-Economic-Performance/

Figure P. Impact of Current U.S. Regulations on Oil Sands Production through 2030

Source: RiskMetrics Group, referencing CAPP 2009 forecast and EIA 2010 EAO



1.5 Low Carbon Fuel Standards

Low Carbon Fuel Standards (LCFS) aim to regulate and reduce the carbon intensity of transportation fuels in a comprehensive way, using the life cycle of the fuel on a “field-to-wheels” basis. These standards provide incentives to reduce greenhouse gas (GHG) emissions at the extraction, processing and distribution stage of the fuel, or what is called “field-to-pump.” At the “pump-to-wheels” stage, refined oil sands products have the same carbon intensity as conventional gasoline per gallon consumed.

LCFS is being considered as regulatory tool both to reduce GHG emissions as well as dependence on foreign oil. It is being adopted as a climate change mitigating strategy in the United States, Canada and the European Union.

- California led the way with the passage of the California Global Warming Solutions Act of 2006 (Assembly Bill 32). To implement this bill, the state legislature required the California Air Resources Board (CARB) to adopt a list of discrete, early action GHG emission reduction measures to be implemented and enforced by no later than Jan. 1, 2010. In 2009, CARB adopted an LCFS in which the average carbon intensity of transportation fuels used in California must be reduced by 10% by 2020. Initial progress under this LCFS standard must be reported to CARB in 2011.
- Other states are following California’s example. Eleven Northeastern and Mid-Atlantic states³¹ (from Maine to Maryland) have agreed to develop a regional LCFS, with the framework to be finalized by early 2011.³² Together, these states

California adopted a Low Carbon Fuel Standard in 2009.

31. Maine, Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Pennsylvania, Delaware and Maryland

32. Northeast States for Coordinated Air Use Management (NESCAUM), <http://www.nescaum.org/topics/low-carbon-fuels>

and California comprise approximately 25% of the U.S. transportation fuel market.

- The Midwestern Governors Association (MGA) has also adopted an Energy Security and Climate Stewardship platform that includes a commitment to create a uniform, regional low-carbon fuels policy to be implemented at the state or provincial level. (Ten governors and one Canadian premier have endorsed this proposal.) The Midwestern states represent the Canadian oil sands' largest export market, with three dedicated pipelines extending from Alberta into the Upper Midwest. The MGA seeks to have agreement on the proposed rule in 2010.³³
- The Western Climate Initiative, including seven states and four Canadian provinces, is also developing an LCFS, as is Ontario. In 2009, Oregon committed to develop an LCFS standard, and British Columbia has adopted an LCFS framework that modeled on the California regulation.
- Finally, the U.S. Conference of Mayors adopted a resolution in the summer of 2008 asking for the creation of "guidelines and purchasing standards to help mayors understand the lifecycle greenhouse gas emissions of the fuels they purchase." While not a legislative requirement, this resolution signals additional support for LCFS as a climate change mitigation strategy.

Given these developments at the state and regional level, it is possible that more than 50% of the U.S. market could become subject to LCFS requirements in the years ahead, even if a federal standard is not adopted. Indeed, lack of legislative progress in Washington could accelerate such state- and regional-level action.

Gasoline produced from oil sands has 12% higher carbon intensity on average than conventional gasoline.

Compliance with LCFS

At present, conventional gasoline has an average carbon content of 520 kilograms of carbon dioxide equivalent per barrel of crude on a field-to-wheels basis. (Of these emissions, about 420 kg of CO₂e/barrel³⁴ occur at the pump-to-wheels stage as the fuel is burned.) To meet the LCFS as set forth under the California rule, the carbon intensity of conventional gasoline must be reduced by 10% to approximately 468 kg of CO₂e/barrel on a field-to-wheels basis by 2020.

The carbon intensity of oil sands is significantly higher than conventional crude oil, given the additional energy required to extract, upgrade and refine the fuel at the field-to-pump stage of production. As shown in Figure Q, oil sands mining operations produce 47% more emissions on average than gasoline at the field-to-pump stage (and 9% more emissions on a field-to-wheels basis). In-situ operations produce up to 80% more emissions at the field-to-pump stage (and up to 15% more emissions on a field-to-wheels basis).

Assuming that oil sands from mining and in-situ operations are combined after the upgrading stage for delivery to the U.S. market, the average carbon content of these fuels is 582 kg of CO₂e/barrel on a field-to-wheels basis. This represents 12% greater carbon intensity than conventional gasoline, with a carbon content of 520 kg of

33. The states include Wisconsin, Minnesota, Illinois, Indiana, Iowa, Michigan, Missouri, Kansas, Ohio & South Dakota.

34. Carbon dioxide equivalent refers to the potency of a mix of major greenhouse gas emissions relative to CO₂. It is a means of creating a single unit for all greenhouse gas emissions.

CO₂e/barrel. In order to achieve the LCFS as defined under the California rule, an additional 10% reduction would be required resulting in a carbon dioxide content of 468 kg per barrel. This works out to a total average reduction of 114 kg of CO₂e/ barrel for Canadian oil sands, equal to a 19.6% reduction in carbon intensity on a fields-to-wheels basis.

Figure Q. Carbon Emissions Intensity of Oil Sands Mining and In-situ Processes

Fuel Type	Life Cycle Phase (kg CO ₂ e/bbl crude)				Total
	Vehicle Combustion	% of LCA	Field to pump	% of LCA	Field to wheels
Average US bbl consumed	420	81%	100	19%	520
SAGD SCO	420	70%	180	30%	600
% more intensive			80%		15%
SAGD Dilbit	420	71%	175	29%	595
% more intensive			75%		14%
Mining SCO	420	74%	147	26%	567
% more intensive			47%		9%

Source: RiskMetrics Group, referencing "Growth in the Canadian Oil Sands," IHS and CERA, 2009.

The California LCFS rule requires any producer or supplier of transportation fuels to the California market to meet incrementally lower carbon intensity targets so that the 2020 target average of 468 kg of CO₂e/barrel is achieved over time. A regulated party can meet these annual requirements with any combination of fuels they produce or supply (including the sale of electricity and natural gas as transportation fuels), by lowering emissions in the production process or by applying LCFS credits acquired in previous years or purchased from other regulated parties. Regulated parties must report their performance to CARB annually starting in 2011. The aircraft, rail and marine sectors are not regulated under the California LCFS.

These rules have important implications for the availability and use of carbon offsets as LCFS credits. By creating a cap-and-trade style market for transportation fuels, LCFS credits encourage technical innovation in oil production and throughout the transportation supply chain. Most important, the availability of these credits stimulate demand for electricity, natural gas and renewable fuels as alternatives to petroleum in the transportation market. The next section examines these credits in greater detail.

LCFS Credits

The use of LCFS credits obtained through transportation emissions reductions provides a number of opportunities for oil sands producers to achieve the goals of this carbon regulation. In effect, each barrel of oil sands needs approximately one-ninth of a ton (114 kg) of CO₂ reductions to comply with the 468 kg of CO₂/barrel limit set by the California rule for 2020. Put another way, each ton of CO₂ reductions achieved through the purchase of LCFS credits would enable roughly nine barrels of oil sands production

Oil sands would need to reduce their carbon intensity in gasoline by 20% to meet the California LCFS.

A \$100 price/ton for LCFS credits would raise the delivery costs of oil sands by \$11.40 per barrel.

(mining and in-situ combined) under the California standard in 2020. In turn, each \$10 increment in the price per ton of these credits would raise the delivery cost of oil sands by about \$1.14 per barrel. A \$100 price per ton in 2020, for example, would increase the average delivery cost of oil sands by \$11.40 per barrel. Hence, the purchase of such LCFS credits would be a viable compliance option for oil sands producers as long as global oil prices were high enough to absorb this effective price increase.

Canada's oil sands producers are prodigious emitters of carbon dioxide, however, and would need to purchase a substantial amount of offsets if they were to rely on this approach. Altogether, oil sands producers are Canada's fastest growing source of GHG emissions, with their emissions projected to rise from 5% to 15% of the nation's total emissions by 2020. It is unclear whether a carbon trading market can emerge that would grow fast enough to sustain the level of offsets that Canadian oil sands producers would require.

With respect to purchasing LCFS credits, the pool of available offsets may be further restricted by regulations set forth under state standards. As noted above, the California LCFS limits the creation of offsets and credits to other parties within the transportation sector, where GHG reductions are generally more expensive to achieve than in other sectors (such as power generation and industrial production). Such a limited pool and higher allowance prices could especially disadvantage oil sands producers, whose average production costs are already higher than for conventional oil producers.

In addition, conventional petroleum producers would need to purchase proportionately fewer offsets to meet the LCFS requirements, since they face a 10% average carbon reduction requirement vs. a 20% average reduction for oil sands producers. Given that conventional oil providers represent a much larger portion of the petroleum market, with lower marginal costs on a per-barrel basis to achieve compliance through offset purchases, they potentially could buy up the market for applicable transportation sector credits and leave oil sands producers with only the most expensive purchase options—or possibly none at all. The terms of the California LCFS makes this scenario more likely with its limitations on emissions trading to parties within the transportation sector. The Northeast states are still deciding how they would define the market for LCFS credits, but tend to follow California's lead on matters like this.

Carbon Capture and Sequestration

The use of carbon capture and sequestration (CCS) is another offset option available to oil sands producers. With respect to achieving compliance with LCFS, the formula for calculating the offsets is the same as described above. For each ton of CO₂ sequestered through CCS technology, roughly nine barrels of refined oil sands could meet the LCFS requirements as defined under the California rule in 2020. Therefore, CCS also could be an attractive compliance option if its market price is less than that of other LCFS credit options. At present, however, CCS remains an unproven technology at a commercial scale in Alberta, with estimated costs ranging from CAD \$70-\$150 per ton of CO₂ sequestered.³⁵

35. "Carbon capture to cost \$3 billion a year to succeed," Daily Oil Bulletin, July 25, 2009. [Article cites an estimate by Jim Carter, former president Syncrude Canada.]

In addition, Alberta's oil sands are not in a favored geographic location for carbon sequestration. Extensive pipeline networks would have to be built to ship the CO₂ to underground reservoirs located up to 1,000 miles away, where the CO₂ could be used to enhance oil recovery from mature Canadian oil fields. Further, a host of legal, regulatory and permitting issues still would have to be overcome. Liability issues present a particular challenge, since the sequestered carbon would need to remain safely stored for hundreds or even thousands of years. It is unclear whether private corporations or insurers could offer such centuries-long assurances.

A study by RAND Corp. suggests that if CCS can be demonstrated successfully at a commercial level, it would add \$3-6 per barrel to costs of oil sands mining operations and \$4-9 per barrel for in-situ operations.³⁶ However, a key assumption made in this study is that 85% of all "well-to-pump" emissions associated with oil sands production would be captured. In reality, most CO₂ emission streams associated with oil sands production are diffused throughout the production process. It is far more likely that producers would focus on the portions of their operations yielding high concentrations of CO₂, such as upgrading and hydrogen processing that account for only 10-30% of total upstream emissions.

The Province of Alberta is weighing a policy that would require oil sands upgrader facilities to operate CCS-ready facilities after 2018 for projects that come onstream after 2012. This still would leave Canadian oil sands producers on a high emissions growth trajectory as their production expands. Even with a higher CO₂ capture rate of 30-50% by 2050, the "well-to-pump" emissions from growing oil sands production could exceed the entire carbon budget for Canada recommended by the Intergovernmental Panel on Climate Change, which calls for an 80% reduction in the nation's overall emissions by 2050.³⁷

Meanwhile, since 2007 the Alberta government has imposed a CAD \$15/ton levy on CO₂ emissions and made CAD \$2 billion available to support commercial demonstration of CCS technology. However, neither the "carrot" of funding support nor the "stick" of the levy has prompted much CCS activity among Canadian oil sands producers. In fact, eight producers withdrew bids for a share of this government support in 2009. This leaves the Athabasca Oil Sands Partnership, operated by Royal Dutch Shell, (with 20% minority stakes held by Chevron Canada Ltd. and Marathon Oil Sands L.P.), as the only oil sands producer to participate in this subsidy program. The proposed Quest CCS project, receiving CAD \$745 million in government funding, would be located at Shell's Scotford Upgrader, near Fort Saskatchewan, Alberta.

Alberta's CCS Task Force estimates that the initial cost of CCS at oil sands upgraders and hydrogen facilities is in a range of about CAD \$75 to \$115/ton of CO₂, taking into account a \$15-20/ton levy on CO₂ emissions.³⁸

Carbon capture technology is costly and unproven at commercial scale.

36. Michael Toman, et. al., "Unconventional Fossil Fuels: Economic and Environmental Tradeoffs," RAND Corp., Technical Report 580, 2008. [Sponsored by the National Commission on Energy Policy.]

37. "Carbon Capture and Storage in the Alberta Oil Sands — A Dangerous Myth," World Wildlife Fund (UK) and The Co-operative Bank, October 2009. [The referenced projection for 2050 assumes that Canadian oil sands production reaches 5.8 mbbbl/d at that time.]

38. "Accelerating Carbon Capture and Storage in Alberta," Alberta Carbon Capture and Storage Development Council, Interim Report, Oct. 2008.

Ambitious targets have been set to increase production of advanced, low-carbon renewable fuels.

Renewable Fuel Standards

One other carbon mitigation option available to high-carbon crude producers such as oil sands is to blend their fuel with low-carbon renewable fuels in order to meet LCFS requirements. To date, most low-carbon fuels are made from blending with biomass-based feedstocks, such as corn-based ethanol. However, depending on the energy and production processes used to make corn-based ethanol, this option may not provide a sufficient reduction in carbon intensity to meet the LCFS standard. Accordingly, the viability of this option for oil sands producers depends largely on the development of advanced biofuels that offer greater carbon reduction opportunities, such as cellulosic ethanol.

The U.S. Renewable Fuel Standard (RFS), adopted in 2005, promotes the use of biofuels as a way to reduce dependence on foreign oil. The RFS initially called for the production of 7.5 billion gallons of biofuels to be produced by 2012. Under the Energy Independence and Security Act (EISA) of 2007, an additional target of 36 billion gallons of annual biofuels production by 2022 was established. The EPA has developed a Renewable Fuel Standard 2 (RFS2) program with specified annual volume standards for biofuels with substantially reduced carbon intensity. These include cellulosic biofuels, biomass-based diesel, other advanced biofuels and other renewable energy options for use in the transportation sector. The revised RFS2 was finalized in February 2010, with an effective date of July 1, 2010, and applies to all biofuels produced or imported in 2010.³⁹

Starting from low production volumes in 2009 (estimated 9 billion gallons of mainly corn- and soy-based ethanol), this target eventually will rise to the 36-billion gallon requirement by 2022, as set forth under EISA. Hence, RFS2 should substantially increase the volumes of low carbon biofuels available for blending. According to EPA, RFS2 should enable biofuels to represent about 7% of expected annual gasoline and diesel volume in 2022.

Advanced low carbon biofuels—such as cellulosic ethanol from crop residues and wood stalks, and advanced biofuels derived from algae—have been targeted to meet the higher volume requirements. The EPA’s plan calls for corn-based ethanol to be capped at 15 billion gallons a year by 2015, while cellulosic ethanol is scheduled to grow to 16 billion gallons annually by 2022, providing nearly half of the volume for the RFS2 target.

To qualify as a viable low carbon fuel substitute, biofuels under the RFS2 must achieve at least a 20% percent reduction of total life cycle GHG emissions (kg CO₂e/bbl) relative to the average conventional gasoline or diesel available in 2005.⁴⁰ For oil sands that face the LCFS requirement in the United States, both the volume and

39. “EPA Issues Final RFS2 Rule,” Evolution Fuels, Feb. 2, 2010. <http://www.evolution-fuels.com/Blog.aspx?id=125>

40. Biofuels that fulfill the lifecycle GHG emissions reductions include: ethanol produced from corn starch at a new (or expanded capacity from an existing) natural gas-fired facility using advanced efficient technologies that we expect will be most typical of new production facilities that complies with the 20% GHG emission reduction threshold; biobutanol from corn starch that complies with the 20% GHG threshold; ethanol produced from sugarcane that complies with the applicable 50% GHG reduction threshold for the advanced fuel category; biodiesel from soy oil and renewable diesel from waste oils, fats, and greases that complies with the 50% GHG threshold for the biomass-based diesel category; Diesel produced from algal oils complies with the 50% GHG threshold for the biomass-based diesel category; cellulosic ethanol and cellulosic diesel (based on currently modeled pathways) that comply with the 60% GHG reduction threshold applicable to cellulosic biofuels. [source: <http://www.epa.gov/OMS/renewablefuels/420f10007.htm>]

Figure R. Renewable Fuel Standard Volume Requirements: 2008–2030

Renewable Fuel Volume Requirements for RFS2 (% potential reductions in CO ₂ e/bbl)					
Year	Cellulosic biofuel requirement	Biomass-based diesel requirement	Advanced biofuel requirement	Biofuels at 20% minimum reduction	Total renewable fuel requirement
2008	0.00%	0.00%	0.00%	20.00%	20.00%
2009	0.00%	2.25%	2.70%	18.02%	22.97%
2010	0.03%	4.44%	3.67%	16.75%	24.88%
2011	1.08%	2.87%	4.84%	16.56%	25.34%
2012	1.97%	3.29%	6.58%	15.39%	27.24%
2013	3.63%	3.02%	8.31%	14.26%	29.21%
2014	5.79%	2.75%	10.33%	12.84%	31.71%
2015	8.78%	2.44%	13.41%	10.73%	35.37%
2016	11.46%	2.25%	16.29%	8.76%	38.76%
2017	13.75%	2.08%	18.75%	7.08%	41.67%
2018	16.15%	1.92%	21.15%	5.38%	44.62%
2019	18.21%	1.79%	23.21%	3.93%	47.14%
2020	21.00%	1.67%	25.00%	2.33%	50.00%
2021	24.55%	1.52%	27.27%	0.30%	53.64%
2022	25.26%	1.32%	27.63%	0.00%	54.21%
2023	25.90%	1.32%	27.09%	0.00%	54.32%
2024	26.55%	1.32%	26.56%	0.00%	54.42%
2025	27.19%	1.33%	26.01%	0.00%	54.53%
2026	27.84%	1.33%	25.47%	0.00%	54.64%
2027	28.49%	1.33%	24.93%	0.00%	54.75%
2028	29.14%	1.33%	24.39%	0.00%	54.86%
2029	29.79%	1.33%	23.84%	0.00%	54.97%
2030	30.45%	1.33%	23.30%	0.00%	55.07%

Source: RiskMetrics Group, referencing U.S. Environmental Protection Agency figures

Cellulosic ethanol has 60% lower carbon intensity than gasoline, but it is not yet commercially available.

carbon intensity of renewable fuels must be taken into account. These also become key parameters for our modeling of RFS2 through 2030.

First, our model derives an annual growth rate for each fuel category in the RFS (cellulosic biofuel, biomass-derived diesel, advanced biofuel and a general renewable fuel category) based on EPA-mandated requirements.⁴¹ We extend estimated volumes (in billions of gallons) of renewable fuels for each category to 2030, based upon the last five-year average annual projected growth rate in RFS2 (2018-2022). The general renewable fuel category (achieving a 20% reduction in GHG content) is phased out by 2022, as production targets for cellulosic and other advanced biofuels are predicted to expand. For biomass-based diesel, we leave the volumes steady at 1 billion gallons. This provides an estimate of the total volume of low carbon renewable

41. The EPA will review performance to the standard each year both in terms of volumes achieved annually and actualized GHG reductions.

fuels that would be available for blending on an annual basis for high carbon oil sands crude to comply with the California LCFS.

As higher volumes of renewable fuels with ever lower carbon intensity enter the market, the average reduction per barrel to be achieved through blending would increase. Based on the biofuel volumes projected under RFS2, by 2022 production of cellulosic, biodiesel and other advanced biomass fuels could achieve a 54% average reduction in kg CO₂/barrel relative to gasoline for oil sands producers that pursue this blending strategy. Because most of the advances come early in the measurement period, our model assumes only a modest further reduction in carbon intensity after 2022, so that the average reduction per barrel reaches 55.1% by 2030. The average reduction in carbon intensity of renewable fuels over the entire modeling period is shown in Figure S.

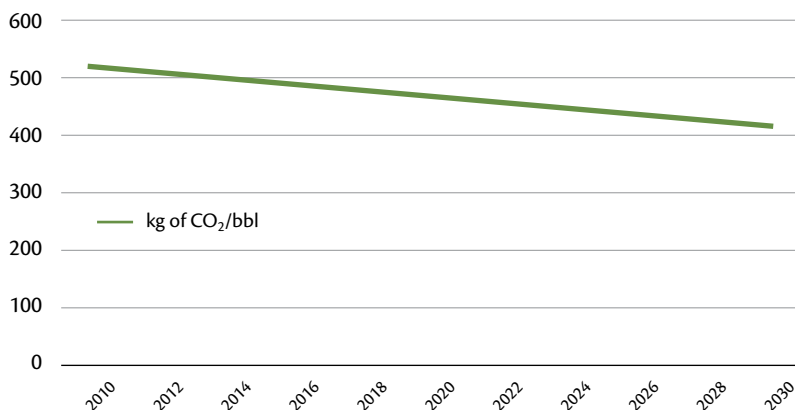
To assess how much oil sands crude can be sold in the U.S. transportation fuels market, our model evaluates the optimal fuel mix that would be required to achieve annual compliance with LCFS, as determined by the EPA's RFS2, with the blended mix achieving the mandated 10% reduction in per barrel carbon intensity by 2020 (i.e., 468 kg of CO₂e/bbl). Our model assumes equal reductions in carbon intensity each year, whereas the California standard requires only moderate reductions in initial years with accelerated reductions in the final years. This has the effect in our model of slightly overestimating the impact on oil sands blending requirements in the early years, while slightly underestimating the impact as 2020 approaches. The total impact over the period is comparable, however.

Our model further assumes that the carbon intensity of oil sands production and conventional petroleum fuels will not change over the study period. However, as more oil sands comes from in-situ production sites, and more conventional oil comes from fields with heavy oil rather than light crude, the carbon intensity of all petroleum fuels could increase.

A 20% reduction in carbon intensity of gasoline would reduce emissions to approximately 420 kg per barrel produced in 2030.

Figure S. Projected Carbon Intensity under LCFS through 2030

Source: RiskMetrics Group, assuming 20% reduction in carbon intensity



Given this concern, our model also assumes that from 2021 to 2030, an additional 10% reduction will be required under the LCFS, on top of the reduction targeted for 2011 to 2020. This would result in a total 20% reduction in CO₂e kg/bbl to be achieved over the 20-year period. Incremental reductions would be required each year to yield an average level of 421 kg of CO₂e/bbl by 2030. (The California LCFS has not set reduction requirements beyond 2020.) As noted above, our model also estimates that a modest 1.1% reduction in the carbon intensity of advanced biofuels would occur between 2022 and 2030, allowing for a 55.1% average reduction in the overall carbon content relative to conventional gasoline by 2030.

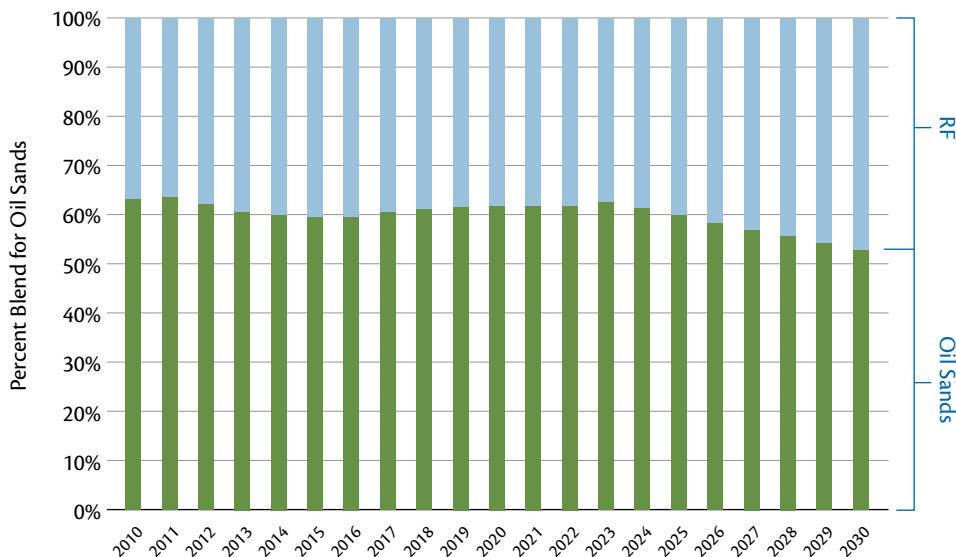
Finally, to determine the maximum impact of the LCFS, our model assumes that the California standard could be implemented by all 50 states, with the first emissions reductions reported in 2011. The sensitivity analysis below also evaluates the effects of having smaller fractions of the U.S. transportation market implementing the California standard.

With the mandated reduction in carbon intensity rising each year under the LCFS, the proportion of renewable fuels required for blending with oil sands crude should rise each year. At the same time, the carbon intensity of available renewable fuels should decline over time, so that the blending requirement is reduced over time. Our model takes account of these two countervailing factors and shows the effect on oil sands blending requirements in Figure T. Starting with modest blending requirements as the LCFS goes into effect in 2011, the portion of renewable fuels blended with oil sands crude is projected to reach 39% by 2020. By 2030, the renewable fuel requirement reaches 48% of the total blend, assuming an additional 10% reduction in the carbon intensity of transportation fuels between 2021 and 2030.

Renewable fuels could account for nearly half of the blend with gasoline derived from oil sands by 2030.

Figure T. Projected Blend of Oil Sand and Renewable Fuels under LCFS

Source: RiskMetrics Group, assuming 20% reduction in carbon intensity

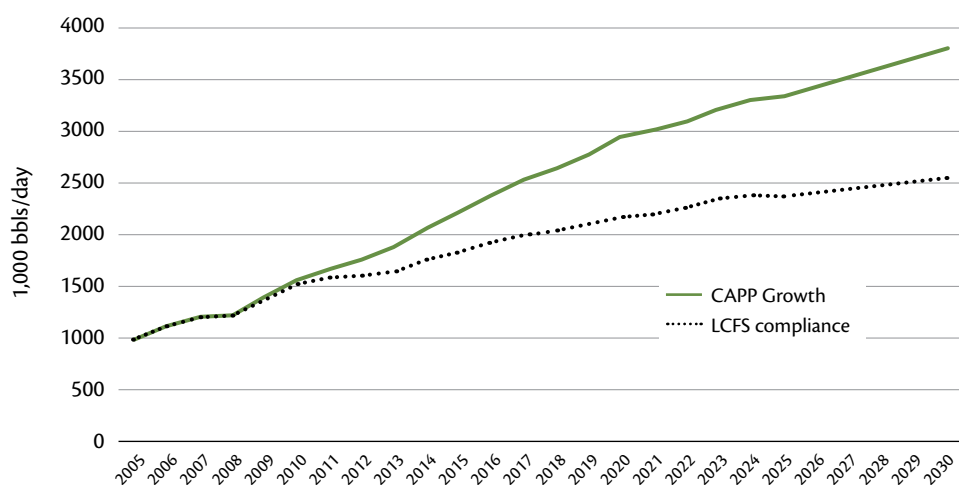


Thus, if Canadian oil sands producers were to rely exclusively on renewable fuels blending to meet requirements of a nationwide U.S. LCFS, with a 20% reduction in carbon intensity by 2030, their portion per barrel of the blended fuel would fall to 52%. Renewable fuels would take the place of this potential oil sands production volume. Assuming that 65% of Canadian oil sands exports to the United States are still devoted to the transportation market, the net effect would be to reduce total production volumes by one-third as of 2030. Comparing this with the CAPP Growth forecast, the annual average growth rate from 2010-2030 would fall from 5.6% per year to 3.4% per year (also taking into account the demand-reducing measures discussed earlier).

A federal LCFS could reduce demand for oil sands by one-third by 2030.

Figure U. Oil Sands Production with LCFS Compliance through 2030

Source: RiskMetrics Group, referencing CAPP Growth forecast



In terms of production volume for advanced biofuels meeting RFS2, our model projects that 1.2 million barrels per day would be available for blending in 2011. By 2030, advanced biofuel production volume could rise to 8.2 mbbbl/d. This is more than twice as much as the amount of advanced biofuels that oil sands producers would require to meet an LCFS adopted by all 50 states, with the average reduction in carbon intensity rising from 10% in 2020 to 20% by 2030.

However, it should be noted that oil sands will also be competing with conventional gasoline to achieve the LCFS requirements. With current projections that conventional gasoline will continue to supply approximately 87% of the U.S. transportation market in 2030, its demand for blended renewable fuels is likely to be substantial. Considering that oil sands may demand 1.2 mbbbl/d of this blended fuel production to comply with the LCFS—or more than 14% of the projected blended fuels market in 2030—a biofuels supply constraint potentially could emerge. Moreover, because the marginal cost of blending these fuels is less for conventional gasoline suppliers (who require lower blended volumes to achieve LCFS), it is likely that oil sands producers would be especially disadvantaged by any supply shortage of advanced biofuels. This may cause them to resort to other options, such as purchasing carbon offsets or investing in carbon capture and sequestration, in order to comply with an LCFS in their main export market.

1.6 Sensitivity Analysis

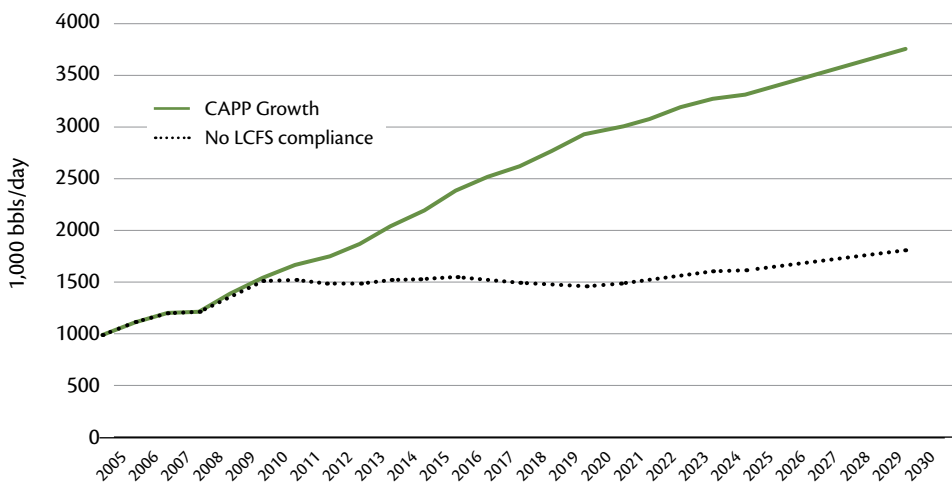
The above conclusion rests on several important assumptions:

- Canadian oil sands producers plan to retain access to the U.S. transportation fuel market by complying with the LCFS, starting first with a renewable fuel blending strategy
- Volumes of renewable fuels set forth in the RFS2 are achieved in each renewable fuel category set forth by the EPA
- The California LCFS is adopted at the federal level and applies across the United States by 2020
- A further 10% reduction in carbon intensity of transportation fuel is required nationwide by 2030

We consequently test each of these assumptions in this sensitivity analysis.

Figure V. Oil Sands Production without LCFS Compliance

Source: RiskMetrics Group, referencing CAPP Growth forecast



Failure to comply with a federal LCFS could reduce oil sands demand below production from projects already in operation and under construction.

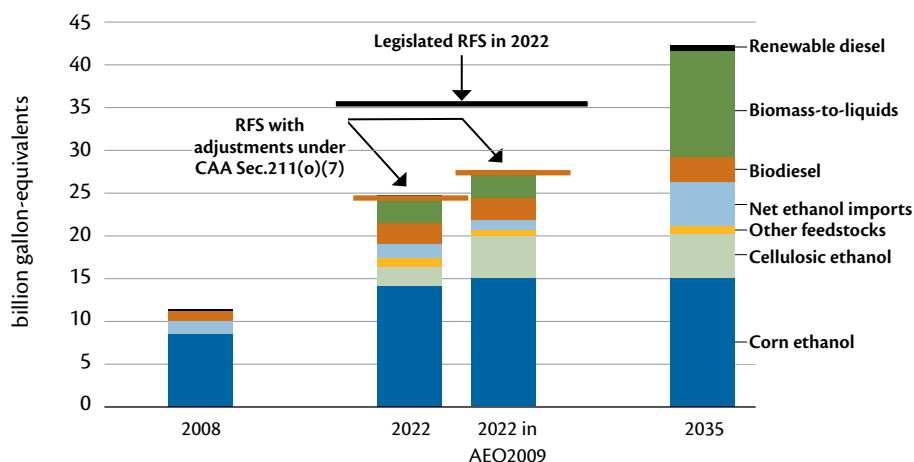
Failure to Comply with LCFS

In the unlikely event that no options were available for Canadian oil sands producers to comply with the LCFS—including no use of blended renewable fuels or other carbon offsets through trading systems—the U.S. transportation market could conceivably disappear for Canadian oil sands producers. If no other markets were to materialize to make up for this loss, oil sands production could be limited to 1.8 mbb/d by 2030, equal to an annual growth rate of only 1.9%, compared to 5.6% under the CAPP Growth forecast. (As with each comparison to the CAPP Growth forecast, this estimate has already incorporated the other demand-reducing measures discussed earlier.) This worst-case scenario would leave oil sands producers with less U.S. demand in 2030 than the estimated 2 mbb/d of production estimated by CAPP for oil sands projects already in operation and under construction.

Figure W. Advanced Renewable Fuel Projections through 2035

Source: RiskMetrics Group, referencing EIA 2010 EIO

Biofuels grow, but fall short of the 36 billion gallon RFS target in 2022, exceed it in 2035



Oil sands producers have a direct incentive to see advanced renewable fuels succeed.

Reduced Renewable Fuel Availability

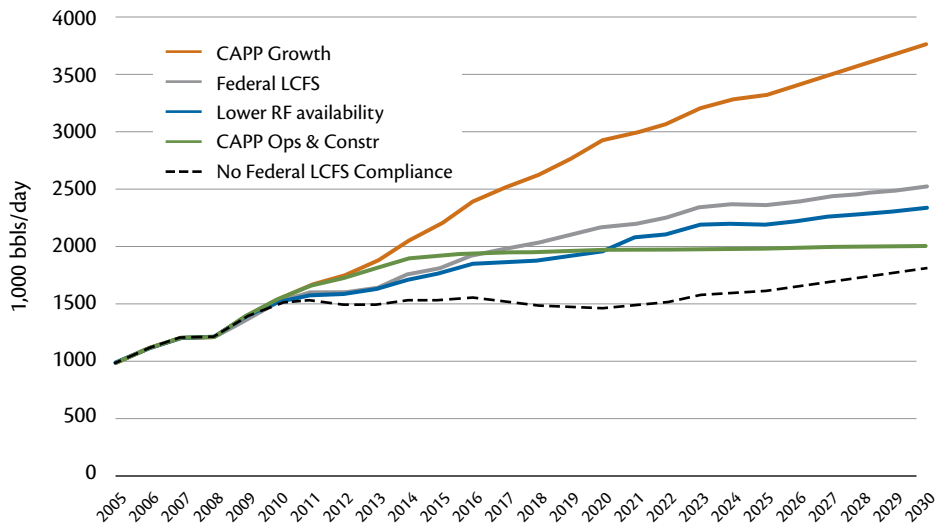
A further consideration is whether the production targets set forth by the U.S. EPA for RFS2 will be achieved. In its 2010 forecast, the U.S. Energy Information Agency estimates that renewable volumes will not reach their target of 36 billion gallons of production by 2022, due primarily to lower projected volumes of cellulosic ethanol, which offers the highest per volume carbon reductions for liquid transportation fuels. The EIA estimates that such renewable production volumes may not approach 36 billion gallons annually until 2030 (see Figure W).

The EPA recently reduced its target for cellulosic ethanol below the level set under RFS2 from 100 million gallons to just 6.5 million gallons for 2010, while maintaining its initial targets for other advanced renewable fuels. The EPA is continuing to monitor the progress of the cellulosic ethanol industry and may make further adjustments to its annual targets. Cellulosic ethanol producers say they need more government tax incentives and risk sharing in order to meet EPA's targets for 2022. Widespread adoption of LCFS would likely spur additional development and production of advanced biofuels, though it is uncertain whether it would be a sufficient catalyst to make up the projected shortfall.

The EIA 2010 forecast also assumes that corn-based ethanol will continue to represent a majority of renewable transportation fuels through 2022. Our analysis assumes that such corn-based ethanol only would achieve an average 20% carbon reduction per barrel under RFS2. This has important implications for our modeling assumptions, because it suggests that a greater amount of renewable fuels would be required under an oil sands blending strategy if corn-based ethanol was being used instead of cellulosic ethanol that offers a 60% carbon-intensity reduction potential. Under these circumstances with greater reliance on corn ethanol, implementation of a federal LCFS, with a 20% reduction in carbon intensity required by 2030, oil sands production would fall to 2.4 mbb/d, down from 2.6 mbb/d. However, this also assumes that other elements of RFS2 would be achieved as proposed by EPA,

Figure X. Oil Sands Production Comparisons through 2030

Source: RiskMetrics Group, referencing CAPP Growth forecast



including 16 billion gallons of cellulosic ethanol production by 2022. This reduced level of production is shown in Figure X and is notably close to production levels projected under the Operating and Construction case issued by CAPP. This raises the stakes for oil sands producers intent on expanding production, particularly as it will depend on increased renewable fuel availability to blend into their fuels. This gives oil sands producers a strong business case to encourage the rapid scaling-up of low-carbon fuels.

No Additional Carbon Reduction after 2020 under LCFS

The reference scenario in our model assumes that the LCFS standard will be extended after 2020, with an additional 10% reduction in carbon intensity required from 2021 to 2030. An alternate scenario holds the LCFS at the 10% reduction level set for 2020 at 468 kg CO₂/bbl will be maintained through 2030 (shown in the dashed line in Figure Y). This would effectively reduce the amount of ethanol blending required to remain in compliance with the LCFS through 2030. At the same time, our model maintains the assumption that there will continue to be modest reductions in the carbon intensity of renewable fuels after 2022, as defined under RFS2, which would further benefit oil sands producers.

Under this alternate scenario, with the carbon intensity reduction held constant at 10% after 2020, the blending requirement for oil sands producers would bottom out at 61% in 2020 (with 39% for renewable fuels) – as depicted in Figure AA. Then, with the increasing carbon reduction potential of renewable fuels through 2030, the blending ratio rises to 67% for oil sands by 2025 (with 33% for renewable

Figure Y. LCFS Carbon Intensity Held at 2020 Level

Source: RiskMetrics Group, assuming 10% reduction in carbon intensity

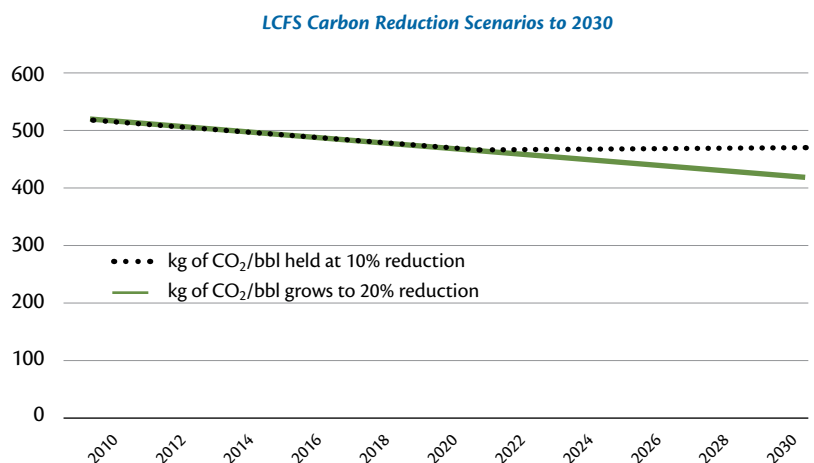
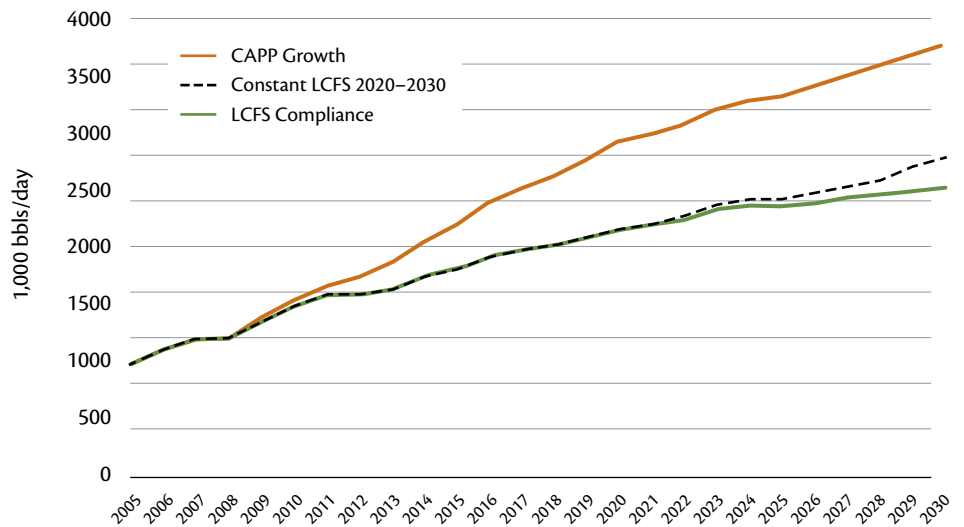


Figure Z. Oil Sands Production under 2020 LCFS Carbon Intensity

Source: RiskMetrics Group, assuming 10% reduction in carbon intensity



fuels) and remains approximately at that ratio for the remainder of the period. This has a positive effect on oil sands production, which would be projected to grow at a 3.9% annual rate from 2010 to 2030, instead of the 3.4% rate under the reference scenario outlined earlier with a 20% reduction in carbon intensity by 2030.

LCFS Applied to Selected States and Regions

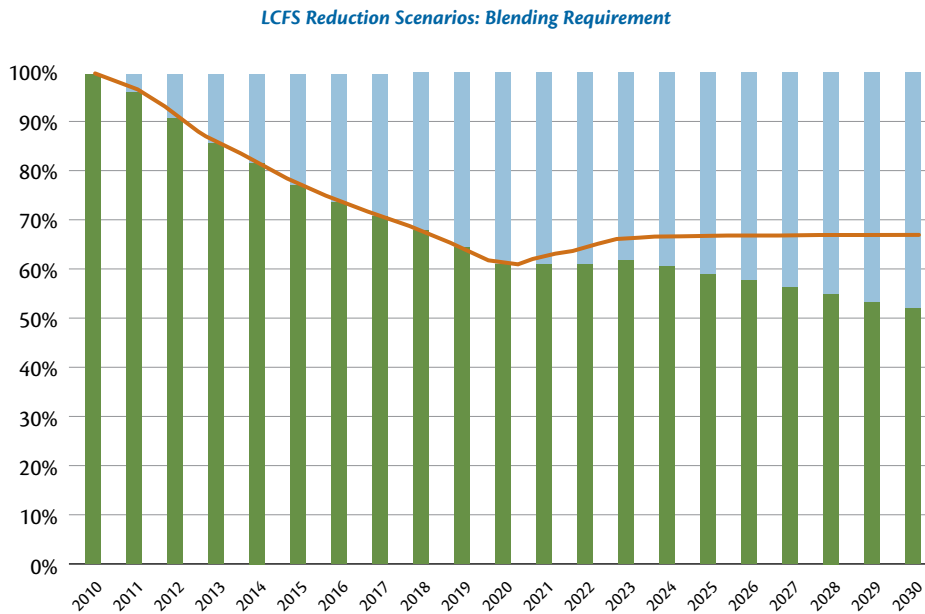
Our reference scenario assumes that the California LCFS will be implemented at the federal level and go into effect nationwide in 2011. However, it is quite possible that the LCFS will be implemented only by certain states or regions. As discussed earlier, California's first carbon intensity reductions under the LCFS for petroleum fuels will be disclosed in 2011. Eleven other states in the Northeast and Mid-Atlantic regions are expected to announce their own LCFS frameworks in early 2011. In combination with California, these states account for approximately 25% of the nation's demand for liquid petroleum fuels.

If these are the only states that implement an LCFS, with the carbon reduction requirement rising to 20% by 2030, the effect on the CAPP Growth forecast (without any federal LCFS regulations) would be to reduce the annual growth rate to 4.5% from 5.6% and reduce oil sands production from 3.8 mmbbl/d to 3.2 mmbbl/d by 2030. Figure BB also makes projections of the effects on oil sands production if 50% or 75% of the U.S. transportation fuel market were subject to a California-type LCFS. A 50% market share for LCFS would reduce the CAPP Growth forecast by 22%, to 2.94 mmbbl/d by 2030, and reduce the industry's projected annual growth rate to 4.15%. At 75%, the annual growth rate would be further reduced to 3.8%.

As a practical matter, the effects of LCFS may have much greater regional distinctions than these averages suggest. For example, California and the Northeast have the least direct access to Canadian heavy crude oil at present. In addition, the Northeast states are considering a phase-in of home heating oil into the mix of fuels subject

Figure AA. Projected Blend of Oil Sand and Renewable Fuels under 2020 LCFS

Source: RiskMetrics Group, comparing effects of 10% (brown line) and 20% reductions in carbon intensity



to LCFS, which might further limit oil sands producers’ penetration of this market. At least 16 other U.S. states import Canadian heavy crude directly, with the greatest concentration in the Midwest. In Montana, 93% of the oil consumed in the state comes from Canada. In Minnesota, Canadian imports account for 83% of the oil consumed, and in Illinois the proportion is 58%. Accordingly, the Midwest likely would have the greatest impact on oil sands production of any region implementing an LCFS standard. As noted earlier, the Midwestern Governors Association has adopted an Energy Security and Climate Stewardship platform that includes a commitment to create a uniform, regional low-carbon fuels policy.

While the Midwest is particularly dependent on imports of heavy crude oil from Canada, this region is also the United States’ greatest source of biofuels. Its ethanol producers are aggressively pursuing policies to promote their greater role in future transportation fuels. Accordingly, an LCFS adopted in the Midwest could work particularly well, since the region already has the infrastructure in place, including pipelines and refineries, to connect with Canadian oil sands. At the same time, this connection could stimulate U.S. employment, promote investments in clean technology and help achieve the goals set forth under RFS2.

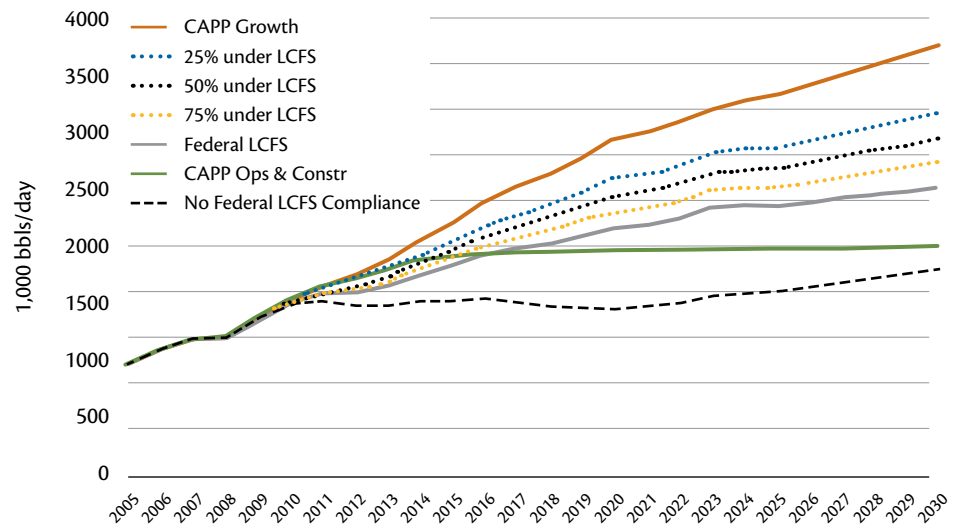
According to a 2009 analysis by Bio Economic Research Associates, a private research and advisory firm:

- Direct U.S. job creation from advanced biofuels production could reach 29,000 by 2012, rising to 94,000 by 2016 and 190,000 by 2022.
- Total job creation, accounting for economic multiplier effects, could reach 123,000 in 2012, 383,000 in 2016, and 807,000 by 2022.

Oil sands producers already have strong ties to the US Midwest, the greatest source of biofuels supply.

Figure BB. Projected Oil Sands Production under Regional LCFS through 2030

Source: RiskMetrics Group, referencing CAPP Growth and Operating & Construction forecasts



- Investments in advanced biofuels processing plants alone could reach \$3.2 billion in 2012, rising to \$8.5 billion in 2016, and \$12.2 billion by 2022. Cumulative investment in new processing facilities between 2009 and 2022 would total more than \$95 billion.
- In addition, direct economic output from the advanced biofuels industry, including capital investment, research and development, technology royalties, processing operations, feedstock production and biofuels distribution, could rise to \$5.5 billion in 2012, reaching \$17.4 billion in 2016, and \$37 billion by 2022.⁴²

1.7 Modeling Conclusions

Our modeling results suggest that, under a business-as-usual scenario, Canadian oil sands producers may be able to achieve the Growth forecast set forth by the Canadian Association of Petroleum Producers (CAPP) of 3.7 mmbbl/d by 2030. This is mainly dependent on future U.S. demand for liquid petroleum fuels, and assumes that no other production- or demand-limiting factors come into play. The effects of U.S. legislation to stimulate production of more fuel-efficient, hybrid and electric vehicles are expected to have only a modest effect on oil sands production forecasts, possibly eliminating the need for 0.3 mmbbl/d of production by 2030.

Adoption of Low Carbon Fuel Standards (LCFS), on the other hand, could have a much more significant impact. Our model shows that compliance with a U.S. federal standard that seeks a 20% reduction in the carbon intensity of liquid transportation fuels between 2010 and 2030 could eliminate 1.2 mmbbl/d of oil sands production by 2030—a 33% reduction relative to the CAPP Growth forecast. This reference

42. "U.S. Economic Impact of Advanced Biofuels Production: Perspectives to 2030," Bio Economic Research Associates, Feb., 2009.

scenario also assumes that advanced renewable fuels will be available in sufficient quantities to provide for blending with oil sands crude, and that the cost of bringing this blended fuel to market will not put oil sands producers at a distinct disadvantage relative to conventional petroleum producers.

These are critical assumptions that may not pan out and which could result in significant additional downward pressure on oil sands production. Low carbon-intensity, renewable fuels may not be available in sufficient quantities to meet the fuel-blending requirements that RFS2 has set for 2022. This gives oil sands producers a direct incentive to support and invest in renewable fuels production to help meet these goals.

If the renewable fuel blends fall short of these goals, oil sands producers would have to resort to other options in order to comply with the LCFS. These include the purchase of LCFS carbon allowances to offset the higher carbon content of oil sands crude and investment in carbon capture and sequestration (CCS) technology to store emissions underground. We estimate that a \$100 per ton price on transportation sector carbon dioxide offsets would effectively increase the price of oil sands production by about \$11.40 per barrel relative to the price of conventional crude on a field-to-wheels basis, placing oil sands producers at a further cost disadvantage in their production costs. Any further carbon levies at the consumption level should affect oil sands and conventional oil producers equally—but would disadvantage both relative to alternative lower-carbon and no-carbon fuels.

The pool of transportation sector offsets available to oil sands producers will determine what role this option might play in coming years. The California LCFS, for example, restricts the use of carbon offsets to parties within the transportation sector, where GHG reductions are generally more expensive than in other markets. Such a limited pool of offsets, and the resulting higher allowance prices, could especially disadvantage oil sands producers. In addition, successful deployment of CCS technology remains uncertain and is at least 10 to 15 years away from wide scale commercial application. Moreover, the amount of emissions likely to be sequestered is still likely to leave Alberta's oil sands producers as major growing carbon emitters, complicating Canada's federal GHG reduction goals.

Another consideration is whether added costs of oil sands production through levies on carbon emissions and deployment of CCS technology could further raise production prices to the point that oil sands can't compete on the market. At present, global oil prices need to be sustained above \$65 per barrel, and possibly range above \$95 per barrel, to justify investments in oil sands production. Production costs may go higher still as more consideration is given to water constraints, tailings pond management and other environmental issues (which are discussed later in this report). Therefore, oil sands producers face particular challenges in passing these added costs onto consumers, especially given that the global oil market through 2030 is likely to be driven by conventional oil producers that produce most of the supply with far fewer constraints.

These conventional producers, in combination with global demand, will continue to set the market price for oil. Oil sands producers will not be in a position to shape these market trends. It follows that oil sands producers may not be able to pass all of their added carbon production costs onto consumers. Accordingly, the global price

Pricing carbon and limiting emissions will increase the delivery price of oil sands.

Low Carbon Fuel Standards and lack of access to other export markets could greatly curtail demand for oil sands.

of conventional oil must be able to sustain the costs of synthetic crude oil sands production and related carbon mitigation strategies.

At the same time, if global oil prices spike too high, perhaps in a range of \$120 to \$150 per barrel, the conservation-inducing effects and stimulus for alternative energy production may crimp oil sands production.⁴³ At that point, other demand-reducing and alternative-supply measures may come into play. Accordingly, in the foreseeable future, oil sands producers must operate within a narrow financial window where oil prices must maintain relatively stable and moderate pricing levels—something that has rarely happened in the increasingly volatile global oil market.

Perhaps the biggest uncertainty of all is whether Canadian oil sands producers will find markets for their products outside of the United States, which presently consumes more than two-thirds of all Canadian oil production. Asia remains a vast, growing and virtually untapped market for oil sands producers. However, reaching that market would require major investments in new pipelines, refineries and shipping capacity, and faces legal roadblocks from First Nation communities opposed to such expansion. Other oil producers from the Middle East and Russia have much more ready access to the Asian market.

Finally, oil sands producers must confront the reality that they produce one of the world's most carbon-intensive fuels. As described earlier in this chapter, efforts to reduce the carbon intensity of U.S. transportation fuels may force oil sands producers to look for new markets as they seek to expand production. But as carbon emissions constraints become more of a global priority, these other markets also may offer diminishing returns. Even within Canada, oil sands producers face the specter of becoming one of the largest and fastest growing sources of carbon dioxide emissions at a time when Canada is committed to major emissions reductions.

For investors, this raises a series of questions to address with oil sands producers:

- To what extent do they expect to continue to rely on the United States as their dominant export market?
- How do they intend to address the emerging challenge posed by Low Carbon Fuel Standards and other carbon-restricting regimes?
- Will they be able to secure sufficient supplies of affordably priced advanced biofuels to blend with their products?
- What investments will they make in renewable fuels, carbon capture and sequestration and other carbon offsets to reduce their carbon footprint?
- Finally, and most importantly, can they assure investors that their products will remain economically viable and sustainable as they address not only the carbon challenge, but also the water, reclamation, Indigenous rights and other issues addressed in this report?

43. "Growth in the Canadian Oil Sands: Finding a New Balance," Cambridge Energy Research Associates (CERA), Mar. 2009.

2. Water and Oil Sands Production

Sustained demand for carbon-intensive transportation fuels is not the only risk factor affecting future oil sands development. Water also poses a potentially critical constraint. Oil sands production is highly water-intensive. For each barrel of synthetic crude produced through oil sands mining, up to four barrels of freshwater are consumed. For in situ projects, less than a barrel of water is consumed for each barrel of SCO produced.

Existing and planned oil sands mines may divert more than 500 million cubic meters of water annually from the Athabasca River in Alberta.⁴⁴ At times of low flow, especially in the winter, this diversion could threaten fish habitat. Our analysis indicates that oil sands producers dependent on securing fresh water supplies may encounter shortages by 2014 unless they make additional investments in water storage and treatment facilities.

In-situ oil sands producers also face new rules on the measurement, use and recycling of water at their facilities. In particular, these operators are being encouraged to use saline aquifers rather than fresh groundwater. The long-term availability of these aquifers and the impacts of large scale extraction on regional hydrogeology remain uncertain.

While Alberta's oil sands resources lie in the region the world's third largest watershed, known as the Mackenzie River basin, the province has a relatively dry climate—which could become even more so due to climate change. The Athabasca Glacier in the Columbia Ice Field, which feeds the Athabasca River, has already receded 1.5 kilometers and lost half of its volume. According to Dr. David Schindler, an ecology and water expert at the University of Alberta, climate impacts could reduce the Athabasca River's flow by 50% in winter months by mid-century.⁴⁵ This could be a key constraint in maintaining uninterrupted production from oil sands operations.

2.1 Water Primer

Currently, commercially employed oil sands technologies are exclusively water-based. Water is a critical element of oil sands operations, as it is part of all aspects of production—from extraction, to separation, to upgrading. Water utilization differs in mining and in-situ recovery processes.

In mining extraction, the crushed oil sand is mixed with water and transported via pipeline to separation facilities where it undergoes a separation process. This hydrotransportation serves as a conditioning process facilitating the separation of bitumen from sand. In the primary separation, the bitumen froth is removed and further transported via pipeline to upgrading facilities. The sand, along with excess water mixed with clay, residual bitumen and other toxic compounds are deposited in large tailing ponds. In these ponds, fine clay suspended in the water settles out over

Oil sands mining requires four barrels of freshwater for every barrel of oil produced.

44. "Lines in the Sands: Oil Sands Sector Benchmarking," Northwest & Ethical Investments, published by Ceres, Nov. 2009.

45. David Schindler and Vic Adamowicz, "Running Out of Steam? Oil Sands Development and Water Use in the Athabasca River-Watershed: Science and Market-Based Solutions," University of Toronto (Munk Centre), May 2007.

In-situ operators use less water but still face resource and regulatory constraints.

a period that typically takes several decades, allowing water recovery and eventual soil reclamation. On average, two thirds of the water used is recycled back into the extraction process, but fresh, so-called *make-up* water is continuously required.

All in-situ technologies, including the most commonly used steam-assisted gravity drainage (SAGD), entail water withdrawal primarily from underground aquifers, injection of steam back underground, and pumping of the bitumen and water mixture to the surface. With the bitumen froth, produced water is also pumped above ground, which allows for significant water recycling. However, similar to mining, some make-up water is also needed to meet the steam requirements.

The product of both mine and in-situ extraction— bitumen froth—is piped to upgrading facilities where it undergoes further separation from residual water and clay. Water use in upgrading includes hydrotreating and cooling, while solvents are used to synthesize the heavy bitumen into synthetic crude oil, suitable as refining feedstock.

2.2 Catalysts for Sustainable Water Management

Large-volume water requirements for oil sands mining and in-situ extraction place a particular need on responsible water management, especially for water recycling and associated treatment. Seasonal changes in water availability make it especially important that mining producers invest in water collection and storage. In-situ producers—while facing fewer water requirements overall—also need water for steam generation that results in higher costs of water treatment from various sources, including produced/recycled freshwater and underground saline aquifers. Water management and ultimate reclamation of tailing ponds are contentious issues with highly uncertain costs down the road.

While there is no charge for industrial water use in Alberta, permits for fresh water withdrawal are in place that benefit the oldest oil sand producers. These “legacy” oil sands miners have generous licenses and are at little risk of exceeding their allowances. It is possible that their withdrawals during low flow periods could leave new producers without adequate water supplies. As a result, most new mining projects have built-in water storage to ensure water supply during low-flow periods.

Despite attempts by the Albertan government to address this issue, no agreement has been reached with legacy miners on how they might share their favored water allowances with new producers. The government has put the industry on notice that a collective answer must be found on water management as oil sands development moves forward. This could include banning water withdrawals in critical flow periods for some river systems, such as the Muskeg River, which drains into the Athabasca River—possibly suspending the operations of oil sands producers lacking sufficient water storage.

Mining producers also face growing water management challenges under *Directive 74* of Alberta’s Energy Resources and Conservation Board. Published in February 2009, this regulation requires oil sands miners to disclose specific plans and timelines to speed up the remediation process of existing ponds and progressively treat tailings. (See Section 3.7 for a more detailed description of Directive 74.) At present, only one of eight mining operators is in compliance with this aspect of the directive.

Figure CC. Average industry-wide water use (bbls) per one barrel of synthetic crude oil (boe)

	Water use (bbls) per one barrel of synthetic crude oil (boe)					
	Water (bbls)					
	Gross Water Intake		Net Water Intake		Recycled Water	Recycling Rates
Mining	Low	10	Low	2	8	80%
			High	4.5	5.5	55%
	High	14	Low	2	12	86%
			High	4.5	9.5	68%
	Average	12		3.25	8.75	72%
In-situ	Low	3	Low	0.2	2.8	93%
			High	0.9	2.1	70%
	High	7	Low	0.2	6.8	97%
			High	0.9	6.1	87%
	Average	5		0.55	4.45	87%
Upgrading	Low	3	Low	0.3	2.7	90%
			High	0.7	2.3	77%
	High	5	Low	0.3	4.7	94%
			High	0.7	4.3	86%
	Average	4		0.5	3.5	87%

Source: RMG modeling based on reviewed literature

In-situ operators are not subject to Directive 74, but also face new regulations that seek higher recycling rates of water that goes through their operations. These operators must achieve a recycling rate of 90% for facilities that utilize freshwater and 75% for operations using saline water. At present, eight out of 11 mining operators are in compliance with these regulations. Not all sites have access to saline water, however. Two of the three in-situ producers that are not yet in compliance are companies trying to meet the 90% recycling target for utilizing mainly freshwater sources. Existing projects have until 2014 to comply with this regulation.

Improvements in tailings management (discussed in the next chapter) may increase the water recycling rate and make oil sands producers less reliant on water withdrawals from the Athabasca River watershed and underground aquifers.

2.3 Water Use

In order to analyze the water availability and tailings issues more closely, we have considered industry-wide data as well as project- and company-specific information. We have reviewed publicly available environmental reports and opinions⁴⁶ in order

46. The list of literature includes, but is not limited to, the following publications:
 "The Sustainable Management of Ground Water in Canada," Council of Canadian Academies, May 2009.
 "Clearing the Air on Oil Sands Myths," The Pembina Institute, 2009.
 "Tar Sands: Dirty Oil and the Future of a Continent," Andrew Nikiforuk, Mar. 2009.
 "Growth in the Canadian Oil Sands," CERA, 2009.

to assess the average barrels (bbl) of water requirements per barrel of oil equivalent (boe) of oil production. Consequently, we retained the widest ranges available within:

- Mining
 - gross water requirement: 10 bbl to 14 bbl
 - net water requirement (gross less recycled): 2 bbl to 4.5 bbl
- In-situ
 - gross water requirement: 3 bbl to 7 bbl
 - net water requirement (gross less recycled): 0.2 bbl to 0.9 bbl
- Upgrading
 - 1.8 bbl water (Shell, Scotford, 2005)

Figure CC maps out the most likely average water consumption and recycling rates. In addition to providing average levels, our analysis considers two fresh water use scenarios for mining projects:

- High, 4.5:1 ratio
- Low, 2:1 ratio

As these results show, mining is a much more water-intensive operation than in-situ production:

- on a net water intake basis, approximately six times more (3.25 bbls/0.55 bbls) fresh water is needed to mine bitumen compared to in-situ recovery
- while the efficiency of bitumen recovery through mining is at 90%, and only between 20–35%⁴⁷ for in-situ projects, the gross water requirement of mined bitumen is on average 2.5 times higher (12 bbls/5 bbls)
- water recycling rates range between 55-80% for mining, compared to 70-93% for in-situ projects

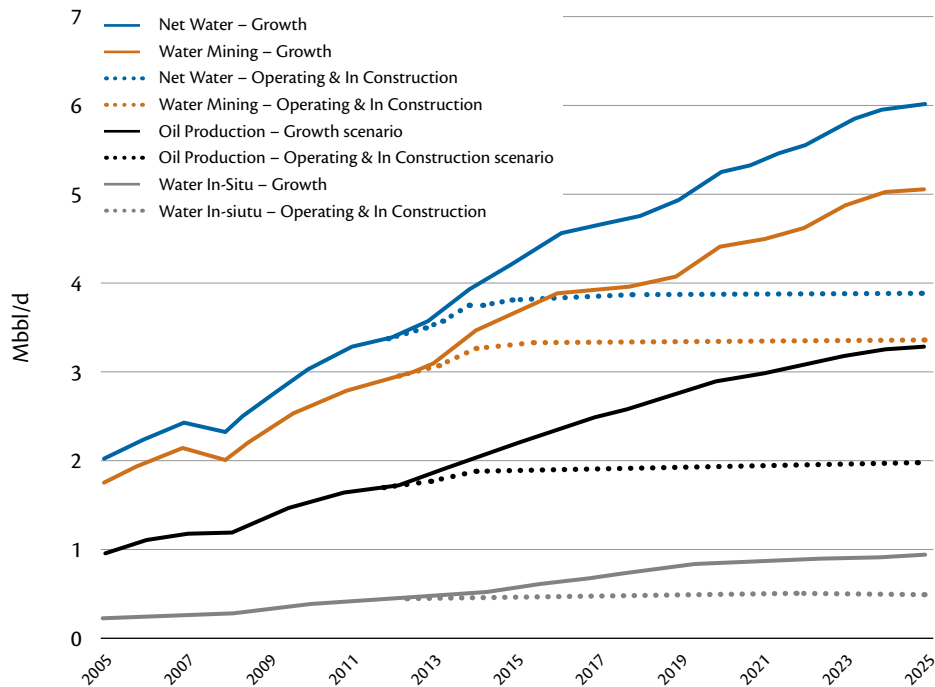
Figure DD considers the cumulative industry water use. We have compiled fresh (net) water needs associated with mining and in-situ production based on the 2009-2025 forecast by the Canadian Association of Petroleum Producers.⁴⁸ As discussed in Chapter 1, this forecast includes two scenarios: a Growth scenario that assumes steady increases in production for the industry, and an “Operating & in Construction” scenario that assumes production only from those projects that are currently operating or under construction. The chart shows the daily estimated net (make up) water use for mining and in-situ, and the cumulative amount for both. The units are expressed in barrels per day and compared against the oil production estimates in order to provide a visual sense of scale.

47. Len Flint, “Bitumen Recovery Technology, A Review of Long Term R&D Opportunities,” Lenef Consulting Limited, Jan. 2005.

48. “2009–2025 Canadian Crude Oil Forecast and Market Outlook,” Canadian Association of Petroleum Producers (CAPP), Jun. 5, 2009.

Figure DD. Cumulative Industry Net Water Use and Oil Production

Source: RMG modeling based on water utilization metrics and CAPP oil sands production forecast



Net water demand for oil sands could triple over 20 years.

2.4 Water Availability

Having determined the cumulative fresh water requirement, the question becomes: How will Alberta’s watershed support projected rates of increase in oil sands production?

Oil sands producers draw water from the following sources:

Mining: As discussed, these producers generally use fresh surface water. There are three key water bodies that correspond to the three main extraction fields: the Athabasca River, the Peace River and Cold Lake. The Athabasca River, which flows through Fort McMurray, is the largest reserve and the only one suitable for surface mining. It represents about 20% of total reserves. Mining and upgrading draws water exclusively from the Athabasca River and Mildred Lake.

In-situ: These producers mostly use underground water, both from fresh and saline aquifers. According to CAPP, more saline water than fresh water has been withdrawn for in-situ extraction since 2007.⁴⁹ Underground water availability is highly localized, with highly saline water less efficient in extracting bitumen from oil sands. Companies need to file water permits only for water with salinity that is below a regulated threshold level. Permits for fresh underground water withdrawal are granted on a project by project basis in connection with an environmental impact assessment (EIA) that includes consideration of regional cumulative impacts on aquifers from all other users, including adjacent oil sands projects. In-situ development, including water permitting, falls under

49. “Water use in Canada’s oil sands,” Canadian Association of Petroleum Producers (CAPP), Aug. 2009.

a different set of regulations and is treated in the same ways as lease contracts for conventional oil producers.

Given the higher water intensity and lower recycling rates of the mining process—averaging 72% vs. 87% for in-situ—mining operations have the biggest water impacts at present. Going forward, however, in-situ projects may have a larger ecosystem impact and account for a growing share of water withdrawals, given that roughly 80% of the total oil sands deposit is available for recovery through in-situ recovery methods.⁵⁰

In-situ operators with high steam-oil ratios need more water and natural gas to produce synthetic crude.

Calculating the water availability constraints for in-situ operators is constrained by a lack of data on underground water availability data. The Pembina Institute, a respected environmental think-tank based in Calgary, Alberta, has conducted a comparative environmental assessment of in-situ projects that will address this issue.⁵¹ Of note is that the steam-oil ratio (SOR) for new oil sands projects is increasing, which means higher volumes of water are required for steam generation in bitumen production. For steam assisted gravity drainage (SAGD) projects, the SORs of earlier projects were around 2:1, meaning two units of steam were required for production of one unit of oil. Some newer projects have SORs as high as 7:1 and 8:1 that imply increased water consumption and power generation needs.

According to the Pembina Institute, the growth of fresh water utilization for in-situ projects is three times higher than the Albertan government forecast of 110 million cubic feet annually. The think tank estimates that even though saline water recycling is now favored under regulations, the industry may still source as much as half of its water needs from fresh water sources as late as 2015. In-situ producers currently account for 7% of total fresh water withdrawals from the Athabasca River, and at peak production it is forecast to withdraw as much water as the mining industry does currently.

In addition, the main by-product of in-situ processes that utilize saline water is accumulated salt. It is estimated that the average SAGD producer annually generates 33 million pounds of salts and water-solvent carcinogens that are destined for landfills.⁵² Salt disposal may become a significant waste disposal issue for producers that could trigger additional environmental management expenses.

Oil Sands Mining and the Athabasca River

As discussed, a potential production constraint for oil sands mining projects is the volume of water withdrawals available from the Athabasca River. The Athabasca River and its tributaries are the exclusive source of water for oil sands operations in the Ft. McMurray region. Oil sands mining operators rely on water licenses granted by Alberta's Energy Resources Conservation Board (ERCB) that specify the maximum level of water that can be drawn from the Athabasca River.

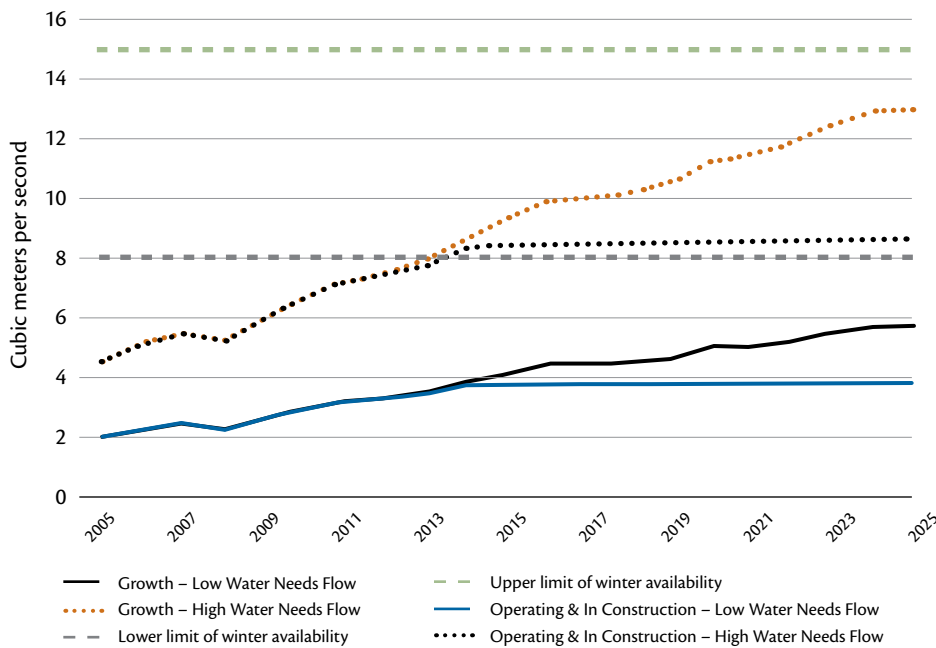
Average total flows from the Athabasca River are roughly 500 cubic meters per second (m³/s). This compares with 5.12 m³/s of average withdrawals by oil sands producers in 2008—or roughly 1% of the total yearly flow. However, flow rates in the

50. Council of Canadian Academies, 2009.

51. Simon Dyer, Jeremy Moorhouse, and Marc Huot, "Drilling Deeper: The In Situ Oil Sands Report Card," The Pembina Institute, Mar., 2010.

52. Andrew Nikiforuk, "Tar Sands: Dirty Oil and the Future of a Continent," Mar. 2009, p.67–69

Figure EE. Comparison of Cumulative Industry Projected Water Usage with Water Availability in the Athabasca River



Mining Water Needs Flow (cubic meters/second)

Water Use under Production Forecast Scenarios		2008	2009	2014	2015	2020	2025
Growth	Low water use ratio [2:1]	2.32	2.69	3.88	4.15	4.98	5.76
	High ratio [4.5:1]	5.21	6.06	8.73	9.33	11.22	12.97
	Average ratio [3.25:1]	3.76	4.37	6.31	6.74	8.10	9.37
Operating	Low ratio [2:1]	2.32	2.69	3.72	3.76	3.82	3.82
	High ratio [4.5:1]	5.21	6.06	8.38	8.46	8.60	8.60
	Average ratio [3.25:1]	3.76	4.37	6.05	6.11	6.21	6.21

Water withdrawals from the Athabasca River are already restricted in winter months to protect fish habitat.

Athabasca River vary greatly by season, ranging from average high flow rates of 859 m³/s in the summer to low flows of 177 m³/s in the winter.⁵³

The provincial agency Alberta Environment (AENV) and the federal agency Fisheries and Oceans Canada (DFO) regulate the maximum amount of water withdrawals to maintain ecosystems dependent on river flows, especially in low-flow periods. At this time, withdrawal rates by all users, including oil sands producers, may not exceed 5.2% of the median river flow.⁵⁴ This restricted period of water withdrawal for oil sands operators extends from October 29 to April 22, with withdrawal limits set in a range of 8-15 m³/s.⁵⁵ In Figure EE, we compare the oil sands miners’ water needs to the lower (8 m³/s) and upper (15 m³/s) regulatory limits. This projection assumes

53. Jennifer Grant and Simon Oxes, “Clearing the Air on Oil Sands Myths,” The Pembina Institute, Jun. 2009.

54. “Growth in the Canadian Oil Sands,” IHS & CERA, 2009.

55. “Water use in Canada’s oil sands,” Canadian Association of Petroleum Producers (CAPP), Aug. 2009.

that average water availability in the Athabasca River will remain unchanged, although summer flows in the Athabasca have declined 29% since 1970 and some studies (as noted earlier) project that winter flows could be cut by as much as 50% by mid-century.⁵⁶ The figure shows that in both the Growth and the Operating & Construction scenarios, when considering the high 4.5:1 water to oil ratio, water withdrawals are moving above the 8 m³/s threshold by 2014; this marks the lower end of the regulated limit of 8-15 m³/s. When considering the average water consumption ratio of 3.25:1 water-to-oil ratio, only the Growth scenario could enter a danger zone of regulatory limitations beginning in 2020.

Oil sands mining operators with the highest freshwater requirements could face supply disruptions as early as 2014.

2.5 Conclusions on Water Management

Our analysis finds that under the high water use rate of 4.5:1, production constraints for oil sands miners could emerge as early as 2014, under both the Growth and Operating scenarios, with producers encountering difficulties in securing water from the Athabasca River in the winter months. Accordingly, by 2014 oil sands producers facing freshwater shortages will need to build water storage facilities to meet continuous production requirements. Producers that achieve a water consumption rate of 2 bbl/boe should be in a better position to maintain their withdrawals under both the Operating scenarios, although this is partly dependent on whether the collective demands placed by producers on the watershed demonstrate a move toward greater efficiency and recycling rates. As oil sands production rises, pressure will mount on all oil sands producers to achieve average water withdrawal ratios of at least below 4:1.

Mining producers presently require four barrels of water on average to produce a barrel of synthetic crude, placing them at much higher risk than in-situ producers, with a ratio below 1:1. Miners lacking generous water allowances granted to Alberta's original oil sands producers need to focus on expanded storage ponds and recycling efforts to address regulatory constraints that could emerge as early as 2014. Water availability may emerge as a key operational constraint for other oil sands producers by 2020.

In-situ producers face higher production costs associated with increased water recycling rates. These producers are much more dependent on tapping underground saline aquifers to liberate bitumen for oil production. This raises in-situ producers' water treatment costs for saline water that is not recycled and must be treated. For in-situ developers, water treatment costs are potentially as high as 5% of total operating costs (see Figure FF).⁵⁷ Operating costs are therefore likely to increase as companies are increasingly forced to use saline water and therefore undergo more expensive water treatment processes. (For further discussion of water management of mining and SAGD projects, see the following section, 3.9 Increased Salt Budgets.)

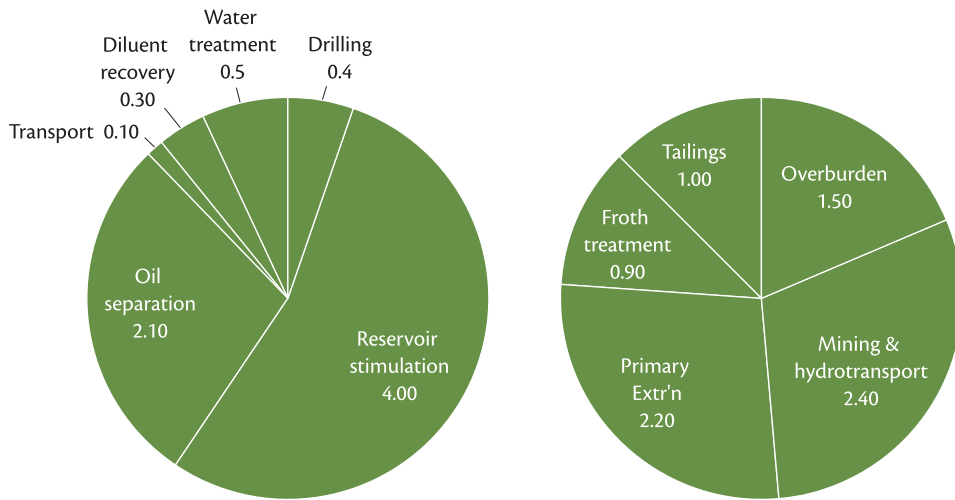
According to a recent industry analysis, the water treatment costs of mining and in-situ projects are roughly comparable, with SAGD producers providing a slight advantage over mining producers (see Figure FF).

56. Peggy Holroyd and Terra Sienieritsch, "Water that Binds Us," The Pembina Institute, 2009, p. 10.

57. Len Flint, "Bitumen Recovery Technology, A Review of Long Term R&D Opportunities," Lenef Consulting Limited, Jan. 2005.

**Figure FF. Water Treatment Costs for SAGD and Mining Operators
(CAD \$ per barrel of oil produced)**

Source: OSTRM/CERI



Water is a key new consideration in any industrial activity in the Alberta oil sands region. Oil sands must compete with agricultural and municipal uses of water for the generous allowances currently provided from the Mackenzie River watershed. Oil sands producers may lose their competitive advantage as more value is placed on these competing demands for water, and as overall availability of water in the province continues to decline.

As outlined in the next chapter, the management of water as it relates to tailings disposal is a far more contentious issue for oil sands operators due to the scale of potential environmental liabilities.

Climate change could increase competition for water in Alberta.

3. Land and Oil Sands Development



DAVID DODGE PHOTOGRAPHY, THE PEMBINA INSTITUTE

Canada's oil sands lie under a vast boreal forest.

3.1 Overview of Land Risks

Alberta's oil sands are located in Canada's vast boreal forest. Impacts from mining and in-situ operations are transforming this landscape and turning one of the world's largest carbon sinks into a fast-growing source of carbon dioxide emissions. Mining operations, in particular, scar the landscape and require large-scale investments in soil remediation and management of toxic petroleum waste in tailing ponds. Restoring this ecosystem is one of the industry's biggest long-term challenges, as the process of reclaiming the landscape and restoring water quality will take decades.

Canada's oil sands industry produces 3.1 million barrels (597,000 tons) of tailings per day — a mixture of water, sand, clay, residual bitumen, organic contaminants (naphthenic acids, ammonia, phenolic compounds), salt and trace metals that are waste byproducts of the extraction processes.⁵⁸ Tailings accumulation is expected to grow along with oil sands production to anywhere between 4.7 and 12.9 million barrels of tailings per day. To date, none of the tailings ponds have been reclaimed and they remain one of the world's largest environmental contaminations.⁵⁹ Tailing ponds substantially alter the ecosystem by contaminating soil and water sources, present health problems in local communities, and pose the risk of a catastrophic breach.

As discussed in the previous water chapter, Alberta's Energy Resources Conservation Board (ERCB) is tightening oil sands water management under Directive 74. This directive requires oil sands mining operators to remediate existing tailings ponds within five to eight years after disposal has been completed and advance the rate at which tailings in other ponds are treated. Because fine tailings (FT) take as long as 40 years to settle, and currently used technology is unable to expedite this process, companies may be forced to use alternative methods such as bioremediation to meet the expedited schedule set by the ERCB.

In this chapter, we discuss our tailings metrics, provide estimates of tailings production and footprint on land, examine the water/soil contamination issues and consequent health impacts in local communities, and estimate potential contingent liabilities for producers. We also review the regulatory catalysts to speed up tailings remediation, such as Directive 74, and evaluate the potential financial impacts on producers.

58. Based on 4.35 bbls of tailings per barrel of oil sands-derived crude oil. The derivation of this metric is presented in the consecutive discussion on land risks.

59. Jennifer Grant, Simon Dyer and Dan Woynillowicz, "Oil Sands Reclamation: Fact or Fiction?" Pembina Institute, Mar. 2008.

Together with the forensic accounting team of RiskMetrics (CFRA), we have quantified the potential increase in asset retirement obligations (ARO) to be included on the balance sheet, along with raising ongoing operating costs on the income statement that companies may incur in complying with Directive 74.⁶⁰ Bioremediation costs would have the most impact on Suncor (SU) in terms of operating expense. If bioremediation were used to treat new daily tailings production, our analysis indicates SU's annual net income could be reduced by 26-104% relative to 2009 income projections. (This estimate does not reflect SU's 2009 merger with Petro-Canada or its plans to use a new proprietary method of treating tailings to reduce this cost.) Meanwhile, Canadian Oil Sands Trust (COST) could see a 10-26% rise in its debt to capitalization ratio, and Imperial Oil (IMO) could see a 6-17% increase in its debt ratio, in order to cover the added costs of bioremediation for treatment of existing tailings in oil sands mining projects.

3.2 Tailings Primer

Tailings are essentially mining waste. To date, current extraction methods—mining and in situ—are both based on water-assisted production of bitumen, whereby warm water (mining) or steam (in situ) is used to separate bitumen from sand. The by-product of this process for mining operations is substantial amounts of liquid petroleum-based slurry that is deposited into tailings ponds. In the case of in-situ operations, produced waste liquids are re-injected into the ground, which raises concerns about possible contamination of underground aquifers.⁶¹ However, the land impact of mining operations is far greater than that of in-situ operations due to the larger tailings component, and is hence the greater focus of our examination.

Oil sands mining involves the cutting of trees and draining of wetlands, the removal and storage of overburden—the top layer of soil, muskeg and vegetation of up to 75 meters—followed by the excavation and crushing of the oil sand ore. This substance is then mixed with warm water and shipped in pipelines to processing facilities, where bitumen froth is separated from the sand, water and clay. The sand separates fast in the primary recovery process and can be further used to construct dikes for the tailing ponds. An average 72% of the used water is recycled back into the production process. The residual slurry of water, clays and the remaining bitumen along with unused sand is discarded into the tailing ponds. The sand settles quickly at the bottom of the pond, but the liquid waste, called tailings, is non-recyclable due to the impermeable content of clay and silt. Residual bitumen is another component of tailings and due to lower density compared to water, it floats on the surface of the tailing ponds. In a matter of three to five years, between 30–40% of such tailings settle at the bottom of the tailing

Toxic tailings ponds now cover an area the size of Washington, DC.



DAVID DODGE PHOTOGRAPHY, THE PEMBINA INSTITUTE

60. Yulia Reuter, Dana Sasarean and Julie Hilt Hannink, "Oil Sands Tailings Pond Remediation Costs Understated," RiskMetrics Group, Dec. 22, 2009.

61. Simon Dyer, Jeremy Moorhouse, and Mare Huot, "Drilling Deeper: The In Situ Oil Sands Report Card," The Pembina Institute, Mar. 2010.

Figure GG. Average Barrel Input/Output in Production of 1 Boe

Average Barrel Input/Output in Production of 1 Boe								
INPUT				OUTPUT				
Barrels of Ore	Barrels of Recycled water *	Barrels of Net (Make-up) Water	Total Barrel Input	Barrels Recyclable Water	Barrels of Liquid Tailings***	Barrels of Tailings Sand **	Total Tailings	Total Barrel Output
4.28	8.75	3.25	16.28	8.75	4.35	4.37	8.72	17.47

*Assuming average recycling rate of 72%

** A factor of 1.4 reflects increase of the volume of sand after bitumen separation process, as the higher density feedstock is converted into lower densities, higher volume tailings sand

*** Both fine tailings (FT) and mature fine tailings (MFT)

Source: RMG modeling based on publicly available environmental information and conversations with industry experts

Oil sands mining produces 17.5 barrels of tailings for each barrel of oil produced.

ponds into what is known as mature fine tailings (MFT)—a deposition of clay and water of a sludge consistency. The remaining tailings, called fine tailings (FT), are fine suspensions of clays that take decades to settle.

The in-situ oil sand extraction involves steam injection into underground deposits and the recovery of bitumen froth. It is pumped to the surface accompanied by produced water, while the “washed” sand remains underground along with the associated liquid waste.

Given that oil sands mining operations generate, on average, 17.5 barrels of tailings per one barrel of oil (boe) produced, the complexities relating to tailings treatment pose enormous medium- to long-term environmental challenges because of the extensive impacts on land and water.

3.3 Tailings Production

As a general rule, about 1.7 tons of oil sands ore (or 4.28 bbls) are processed to obtain 1 boe.⁶² Based on average composition of the ore and the previously presented water model (see Figure CC), we have compiled a resource input/output equation for oil sands mining.

This equation presents a ratio so that one boe results in an average tailings production of 17.47 bbl, of which 4.37 bbl are tailings sand, and 4.35 bbl are liquid tailings that ultimately need to be remediated.

An important output component of our model is liquid tailings (4.35 bbls of tailings per one boe of oil), which is the mining waste that persists in tailings ponds after sand tailings settle and water is recycled. Liquid tailings are composed of mature fine tailings (MFT) and fine tailings (FT), and are broken down as shown in Figure HH. MFT (1.52 bbls on average per one boe of oil) have a tendency to settle to a semi-solid state, and are less of a remediation problem than fine tailings. FT (2.83 bbls/oil boe) represents the biggest remediation challenge for producers.

62. “The Sustainable Management of Ground Water in Canada,” Council of Canadian Academies, May 2009.

Figure HH. Composition of Liquid Tailings in Production of 1 Boe

Composition of Liquid Tailings in Production of 1 Boe							
INPUT			OUTPUT				
Net water use (bbl)	Fines and clay, residual bit and water	Mature Fine Tailings (MFT)			Fine Tailings (FT)	Total Liquid Tailings (bbl)	
		MFT 30%*	MFT 40%*	Average MFT			
Low	2.00	1.10	0.93	1.24	1.08	2.01	3.10
High	4.50	1.10	1.68	2.24	1.96	3.64	5.60
Average	3.25	1.10	1.30	1.74	1.52	2.83	4.35

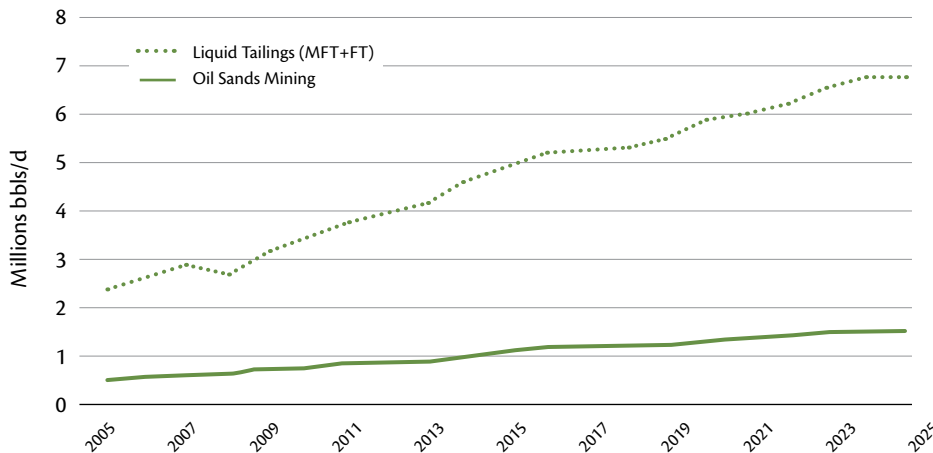
**Sediment settlement ratios - 30%-40% in years to form MFT
 Source: RMG, based on publicly available data: Oil Sands Myths: Clearing the Air, Pembina, 2009
 Tar Sands: Dirty Oil and the Future of a Continent, Andrew Nikiforuk, March 2009
 Growth in the Canadian Oil Sands, IHS & CERA, 2009
 Source: RMG modeling based on publicly available environmental information and conversations with industry experts

Given the above-calculated tailings production per boe, we have estimated that the industry’s tailings production from oil sands mining projects could reach 1.6 million bbl/d by 2025, based on CAPP’s production forecast (Growth scenario).⁶³

Tailings production could reach 1.6 million barrels per day by 2025.

Figure II. Mining Industry’s Oil and Liquid Tailings Production (million bbls/d)

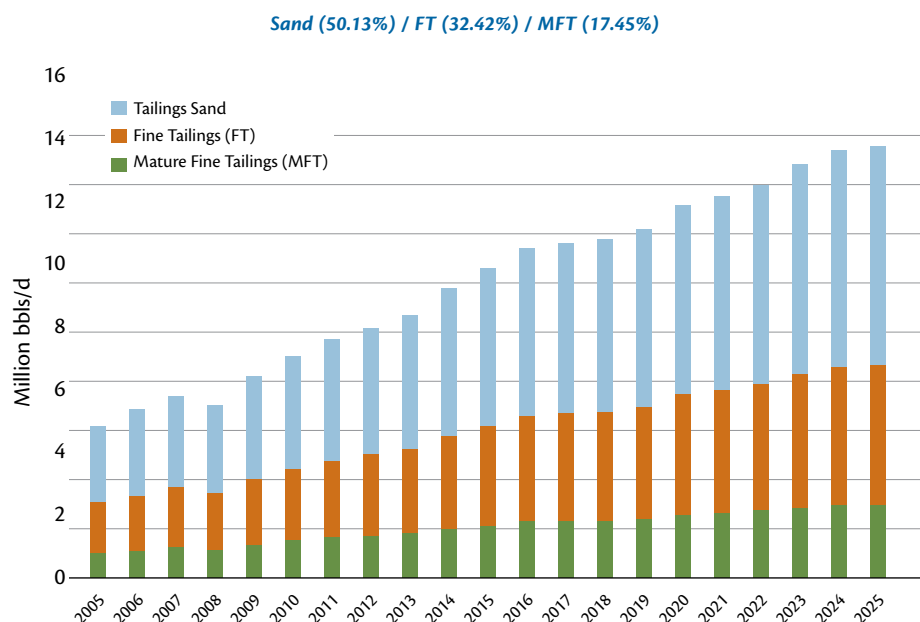
Source: RMG modeling of tailings production based on estimates of CAPP’s production forecast (growth scenario)



63. “2009–2025 Canadian Crude Oil Forecast and Market Outlook,” Canadian Association of Petroleum Producers (CAPP), Jun. 5, 2009.

**Figure JJ. Breakdown of Mining Industry's Tailings Production
(million bbls/d)**

Source: RMG modeling of tailings production based on estimates of CAPP's production forecast (growth scenario)



The Pembina Institute estimates that there are 5.5 billion cubic meters (24.6 billion bbls or 4.7 bn tons) of total tailings currently impounded on Alberta's landscape.⁶⁴ Of this amount, the inventory of fluid fine tailings that require long-term storage is now 720 million cubic meters (3.2 bn bbls or 518 mm tons), according to Alberta's environmental regulator, ERCB.⁶⁵

Given that 55% (715,000 bbls/d) of Alberta's oil sands production came from mining in 2008, we estimate that the industry produced 1.14 billion barrels (218 million tons) of tailings that year (equivalent of 3.1 million barrels or 597,000 tons per day). Based on CERA's range of production forecast scenarios, by 2035 the industry could be producing anywhere between 1.72 bn and 4.7 bn barrels of tailings annually, or 4.7 to 12.9 million barrels per day. On a company level, estimated liquid tailings production at capacity could reach levels presented in Figure KK.

As the industry ramps up production, the scale and pace of tailings accumulation may be increasingly unsustainable, and runs the risk of catastrophic environmental failures. This may lead to further regulatory challenges for producers, including potential project shutdowns.

64. Jennifer Grant, Simon Dyer and Dan Woynillowicz, "Oil Sands Reclamation: Fact or Fiction?," Pembina Institute, Mar. 2008.

65. "ECRB releases major directive on oil sands tailings management and enforcement criteria," Alberta Energy Resources Conservation Board, Feb. 3, 2009. <http://alberta.ca/home/NewsFrame.cfm?ReleaseID=/acn/200902/252143CCA5597-FAC5-D7DC-C49E896F36C6F602.html>.

Figure KK. Liquid Tailings Production at Projected Capacity

	Mining production at capacity (boe/d)	Liquid Tailings Production at Capacity (bbl/d)
Syncrude ¹	500,000	2,173,410
Suncor	462,000	2,008,231
ExxonMobil ²	387,000	1,682,220
Imperial	335,000	1,456,185
Total SA (France)	216,700	941,956
COST	183,700	798,511
Petro-Canada	144,000	625,942
Shell	141,000	612,902
Marathon	48,400	210,386
Chevron	48,400	210,386
Sinopec	45,333	197,056
ConocoPhillips	45,150	196,259
Nexen	36,150	157,138
Occidental	10	134,751
Murphy	25,000	108,671

¹ Syncrude is a JV of COST, Imperial, Suncor (ex Petro-Canada), ConocoPhillips, Murphy, and Mocal.
² Includes 70% of Imperial
Source: RMG modeling based on public disclosure and consultation with industry experts

3.4 Footprint on Land

The latest provincial government statistics indicate that 530 km² of land (53,000 hectares or 35% of land approved for development) have been disturbed by oil sands mining activity to date.⁶⁶ Figure LL summarizes the land footprint of approved and proposed mining projects.

Producers claim that on a voluntary basis 6,498 ha, or 13.6% of disturbed land has been reclaimed. However, to date, none of the existing tailing ponds have been officially certified as remediated. Despite the use of chemical treatment technology by Suncor since 1994 (see the following section on Tailings Management Options), the company has failed to reclaim any of its tailing ponds. Suncor says it plans to reclaim its 40-year old Pond 1 in 2010. However, the FT in this pond essentially is being drained to alternative ponds in order to expose the MFT and allow soil reclamation of the pond surface.

The only remediation certificate filed with regulators was awarded to Syncrude in March 2008 for remediation of 104 ha at the Gateway Hill project; this equals 0.2% of land disturbed by the industry as a whole. The area did not include a tailing pond, and hence the remediation effort involved replacing the overburden and turning what was once a low-lying wetland into a forested upland. In principle, this does not meet the mandated requirement to return the land to the so-called equivalent land capability.

No tailings ponds have been fully remediated in 40 years of production.

66. Government of Alberta, <http://www.energy.gov.ab.ca/OilSands/791.asp>.

Figure LL. Land Footprint of Mineable Oil Sands

ERCB Project Development Area		Attribute	Time Scheme		
Status	(Hectares)		2008	2020	2040
Approved	150,000	Tailings (ha)	13,000	25,000	31,000
Proposed	79,000	Composite Tailings (ha)	1200	7500	6800
		Net Footprint (ha)	52,000	82,000	100,000
Total	230,000	Ratio of Tailings to Footprint (%)	25%	30%	31%

Notes:

- 1) The net footprint area includes all development including tailings and removes reclaimed lands as deemed by the company.
- 2) Composite tailings are rounded to the nearest 100; all other numbers are rounded to the nearest 1000
- 3) Composite Tailings are higher within the 2020 scheme vs 2040 because the South Voyager ETA accepts CT and is 3200 hectares
- 4) 1 km² = 100 ha

Source: RMG modeling based on public disclosure and consultation with industry experts

Air and water emissions are linked with cancer and other health risks in neighboring communities.

3.5 Health Consequences of Water and Soil Contamination

Through the extraction process, tailings concentrate a number of toxic contaminants naturally occurring in the oil sands deposits and bitumen, including naphthenic acids, phenolic compounds, ammonia-ammonium, and trace metals such as copper, zinc and iron.

Health concerns arise from the contaminants’ persistence in the environment and consequent bio-accumulation into living organisms where serious health impacts can occur, from tumors and cancers, to endocrine and reproduction anomalies. Ultimately, serious concerns exist about the impact of naphthenic acids (NAs) and polycyclic aromatic hydrocarbons (PAHs) on human health as reflected in local communities located downstream of the mines that are dependent on local river water for conducting their traditional lifestyles of hunting and fishing.

Over the last several years, several non-governmental organizations such as Environmental Defense, WWF and Greenpeace have drawn public attention in Canada, the United States and Europe to the toxic accumulations in the Mackenzie watershed.⁶⁷ A peer-reviewed scientific study by ecologist Dr. Kevin Timoney, released in the fall of 2007, found higher than average concentrations of more than 20 substances, including arsenic and mercury, in Lake Athabasca and the Athabasca Delta. Residual bitumen also forms a pellicle above the tailing ponds posing risks for wildlife, such as migratory birds. In December 2009, a study by Prof. David Schindler, a water ecologist at the University of Alberta, found that pollution from the oil sands industry may be far greater than industry figures indicate. His research calculates that approximately 34,000 tons of particulates are falling annually near the center of

67. Christopher Hatch and Matt Price, “Canada’s Toxic Tar Sands: The Most Destructive Project on Earth,” Environmental Defence, Feb. 2008.

development. Dr. Schindler says they carry 3.5 tons of raw bitumen and carcinogenic polycyclic aromatic compounds, which is equivalent to a major oil spill, repeated annually, and is toxic to some fish embryos.⁶⁸

Dr. John O'Connor, a physician in Fort Chipewyan from 2000 to 2007, registered three cases of cholangiocarcinoma, a rare bile-duct cancer, in 12,000 people, which normally strikes one to two people in a population of 100,000. He also observed increased rates of leukemia, prostate and lung cancer. The Alberta Cancer Board found elevated cases of two other diseases in the local population: Graves—a type of autoimmune disease that causes over-activity of the thyroid gland, leading to hyperthyroidism—and kidney (renal) failure. It also showed elevated levels of specific cancers, including cancers of the blood known as hematopoietics, which oncologists say includes leukemia. While there is continued dispute over the statistical significance of these findings, and their connection to oil sands pollution, the potential adverse health impacts of oil sands production remains a significant potential risk for the industry.

Aboriginal communities are taking legal action against producers and the government regarding these environmental and social impacts, and infringement on their recognized rights to enjoy a clean environment in order to conduct traditional lifestyles of hunting and fishing. (See Chapter 4 for details on precedents and outstanding lawsuits.)

3.6 Contingent Liabilities

Tailing dams have a propensity to leak. This was evidenced by the breach of a dam in Tennessee accumulating coal ash deposits that spread 1.5 million cubic yards of toxic sludge over hundreds of acres in December 2008.⁶⁹ In the December 2008 report, *The Tar Sands' Leaking Legacy*, Matt Price of Environmental Defence researched the filings of environmental impact assessments for oil sands project applications, and calculated that in 2007, over 4 billion liters of tailings leaked out into the environment. The projected leakage amount in 2012 could reach 26 billion liters.

In the *H2Oil* documentary screened at the Royal Ontario Museum at the Toronto International Film Festival in May 2009, ecologist and water researcher Dr. Kevin Timoney of Treeline Ecological Research also describes the existence of leakage.⁷⁰ His research indicates that Suncor's Tar Island Pond dam, built 300 feet above the Athabasca River, leaks 67 liters of tailings per second, essentially making it a continuous oil spill. Furthermore, Dr. Norbert R. Morgenstern, professor of geotechnical engineering at the University of Alberta, has identified such structural



SUNCOR AND SYNCRUDE'S OPERATIONS PHOTOGRAPHED BY DAVID DODGE, THE PEMBINA INSTITUTE

Tailings ponds are leaking and pose the risk of a catastrophic breach.

68. Erin N.Kelly et al., "Oil sands development contributes polycyclic aromatic compounds to the Athabasca River and its tributaries," *Proceedings of National Academy of Science*, Dec. 7, 2009.

69. David Sassoon, "A Tale of Two Disasters: Coal Ash and Tar Sands Tailings," Dec. 29, 2008, <http://solveclimate.com/blog/20081229/tale-two-disasters-coal-ash-and-tar-sands-tailings>

70. <http://h2oil.com/home/>

issues with the same pond as deformation creep, or movement in a dam's foundation.⁷¹ In general, tailing ponds are built with sand and clay on relatively weak foundations, such as muskeg, or on top of glacial meltwater channels. Dam failure could result in an environmental disaster, potentially equivalent to 300 times the size of the Exxon Valdez spill that released 11 million gallons of oil into Prince William Sound, Alaska, in 1989.

3.7 Regulatory Catalysts

Given the environmental degradation of the boreal forest and wetland habitat, and the public's increased awareness of the environmental problems associated with tailings ponds, regulatory pressure is mounting on producers. In February 2009, ERCB, Alberta's environmental regulator, released Directive 74, which outlined a new tailings remediation compliance requirement. In essence, this directive specifies that the tailing areas for oil sands miners need to become trafficable, i.e., solid enough to support vehicle transit.

Directive 74 calls for faster reclamation of tailings ponds and progressive recycling of tailings.

According to ERCB, as of June 2008, 720 million cubic meters of tailings occupied an area of 13,000 hectares.⁷² Going forward, the ERCB wants to see existing fluids reduced, followed by progressive reclamation, meaning that the ponds will need to be reclaimed and water recycled as producers continue to develop their mines. As a result, mined oil sands operators will have to include tailings treatment costs as part of their ongoing operating expenses and increase the size of their asset retirement obligations (AROs), with some remediation finished over periods of only five to eight years, rather than the entire 20–40 year span of project development.

Furthermore, the directive indicates that companies must plan better for their tailings ponds, developing dedicated disposal areas (DDA) that have to meet specific minimum un-drained shear strength within a year of deposition, and higher standards within five years. Companies filed their first set of plans with the ERCB by Sept. 30, 2009, detailing how they are planning to meet Directive requirements; going forward they will have annual filing requirements. The plan will be phased in over the next four years, allowing for differences between mines. The general timetable for remediation of tailings deposits and tailings receiving progressive recycling treatment is as follows:

- 20% from July 1, 2010, to June 30, 2011
- 30% from July 1, 2011, to June 30, 2012
- 50% from July 1, 2012, to June 30, 2013, and annually thereafter

This phase-in means that beginning in July 2010, 20% of tailings deposits would need to be remediated or recycled progressively. By July 2012, as much as 50% of the produced tailings would require progressive treatment.

Companies are not being required to use any specific technology to meet the goals but can choose from a number of options. Our interpretation of the rules is that existing tailings ponds, where disposal is finished, must become trafficable—i.e.,

71. Andrew Nikiforuk, "Tar Sands: Dirty Oil and the Future of a Continent," Mar. 2008, p. 83.

72. "ERCB releases draft directive on oil sands tailings management and enforcement criteria," Alberta Energy Resources Conservation Board, Jun. 26, 2008.

able to support a specified amount of weight such as vehicle transport—within five to eight years, while new ponds must be made progressively more trafficable five years after their deposits have been extracted and be able to support reclamation activities, such as re-vegetation.

In December 2009, the Pembina Institute published an analysis of the nine remediation plans filed by six companies by the first ERCB deadline in September 2009. It found that only the Fort Hills Energy mine (operator Petro-Canada, now Suncor) and the Suncor Millennium/North Steepbank mine (operator Suncor) will be in regulatory compliance with Directive 74.⁷³ Recent press reports indicate that companies including Imperial Oil and Shell are attempting to convince ERCB to extend the timelines for compliance, reinforcing the findings that most mining producers are not fully prepared to meet this directive.

Only one oil sands mining operator expects to be in compliance with Directive 74.

Other Regulatory Drivers

Environmental compliance of mining and hazardous industries in the province is governed by the Alberta Environmental Protection and Enhancement Act and overseen by the ERCB. The Environmental Protection Security Fund of Alberta is the mechanism that secures finances for the provincial remediation contingency in case of corporate bankruptcies. As of March 31, 2009, the fund's value was CAD \$1.12 billion.⁷⁴ Producers generally make contributions to the fund in the form of letters of credit.

Another regulatory catalyst comes from the development of forest protection regulation, which could potentially result in restricted access to land for future oil sands development. The provincial cabinet has recently instructed the Lower Athabasca Regional Advisory Council to find ways to protect at least 20% of its region; currently only 6% is protected. The Department of Sustainable Resource Development indicated that a plan will need to be drawn up in 2010. This regulation may conflict with current mineral leases, but the provincial government has the right to overrule, provided that compensation is awarded.

3.8 Tailings Management Options

The biggest waste remediation challenge for producers is the suspended liquid tailings material that takes decades to settle. Although tailings settle to mature fine tailings (MFT with 30%–40% solid content) in the first three to five years, the settlement of the remaining FT material happens very slowly. Lack of treatment of organic contaminants within FT has prevented complete settlement of any tailings ponds over 40 years of oil sands industry operations.

Our conversations with industry experts suggest that tailings management has not been successful primarily for economic, not technical reasons.⁷⁵ In fact, the most successful technological experiments date back to the 1990s. In the absence of a

73. Terra Simieritsch, Joe Obad, and Simon Dyer, "Tailings Plan Review," Pembina Institute and Water Matters, Dec. 2009.

74. "Environmental Protection Security Fund: Annual Report," Government of Alberta, http://environment.alberta.ca/documents/EPSPF_AnnualReport_2008_to_2009.pdf

75. RMG conducted interviews with the oil sands companies (primarily Suncor and Imperial), environmental engineers (e.g. ERM, Bennett Environmental, Fiton Technologies), and research (e.g. Randy Mikula, team lead at CANMET Energy Tech Centre in Devon, Alberta, Natural Resources Canada).

regulatory obligation or business rationale, producers for the most part have simply stored tailings in large containment areas. The new impetus for operators to extract water from tailings is the increased operational requirement of water for continued growth in production. Given the increased risk of water shortages discussed in Chapter 2, tailings management for producers has become synonymous with water management.

A number of tailings management methods are in use, including some that are at the experimental, pilot testing stage:

1. Water capping: This is an historical reclamation practice where tailing ponds are capped with fresh water to form end-pit lakes. The industry claims that tailings initially will stay separated due to the different nature and densities of the two liquids. Then, in the long run, the two layers are supposed to mix into a remediated state that will ultimately support viable ecosystems.

This option is highly controversial and unlikely to receive permanent regulatory approval. It is the lowest-cost alternative, and is in fact, not reclamation, but rather a long-term storage option. It was the best available technology for managing tailings before 1989, when the Albertan government first undertook an initiative to encourage the industry to remediate rather than store tailings. Nowadays, this method is generally considered to be obsolete. In 2008, the Tse Keh Nay community successfully set a legal precedent in a case against a Canadian gold miner, Northgate Minerals, which in 2003 had proposed to store acid tailings in the Amazay Lake in British Columbia. Although this precedent affected another mining industry in another province, the court recognized that the environmental assessment process underestimated the risks associated with using aquifers for waste storage, and banned the long-term storage of acid tailings in the Amazay Lake as part of that mine's expansion.

2. Composite Tailings/Consolidated Tailings/Non-segregated Tailings

(abbreviated as CT): This technique is largely based on chemical treatment of tailings to achieve solidification. Essentially, mature fine tailings (MFT) replace water found in sand tailings. Suncor pioneered this treatment process in 1994 with an addition of gypsum and coarse sand into the tailings mix. Alternatively, CO₂, lime, acid & lime, and polymer can be used in place of gypsum.

One note of caution is that CT production competes for sand required for dike construction in tailings ponds. This may compound the challenge of tailings management if CT becomes a preferred treatment option. In effect, an MFT analogue is being used to prevent accumulation of MFT in the first place, making the control process more complicated.⁷⁶ Suncor is moving away from using the CT process, and is instead proposing to incorporate MFT Drying into its regulatory compliance plans.

3. MFT Drying and Accelerated Dewatering: In October 2009, Suncor announced an alternative method to accelerate its tailings remediation operations. This is achieved by adding a polymer that binds to the tailings. The resulting slurry is then spread on a slightly graded slope that allows the water to run off and be treated

76. R.J. Mikula, V.A. Munoz, O.Omotoso, "Water Use in Bitumen Production: Tailings Management in Surface mined Oil Sands," Natural Resources Canada, CANMET Energy, Jun. 17, 2008.

and recycled. The slurry is spread thin to further accelerate the drying process. As a result, Suncor expects to be able to eliminate the need for long-term tailings storage and return solid tailings to the mines as they are generated resulting in revegetated surfaces in 7–10 years post disturbance, whereas prior tailings pond settlement methods took more than 30 years before land reclamation could begin. Over the next two years, Suncor will invest CAD \$1.2 billion in this proprietary tailings remediation process. While this will increase the company's near-term operating expenses, it will reduce its long-term asset retirement obligations by cutting the time requirement for land reclamation by more than half.⁷⁷

4. Carbon dioxide (CO₂) injection: This method, used by CNRL, injects waste CO₂ into the liquid tailings before the slurry enters a pond, where the CO₂ reacts to form carbonic acid. This changes the pH of the tailings mixture, then allows the finer clays, silts and sand to settle, leaving clearer water for recycling.

5. Bioremediation: This process uses microbes and nutrient biostimulants to convert organic contaminants into inorganics such as carbon dioxide and water. It allows for recycling of the freed water and settlement of the FT suspensions that are no longer bound with clay and petroleum residue.

Once the liquid tailings have been disposed of, the treated MFT is covered with returned overburden to conceal the open pit mines, and eventually re-vegetated.

Bioremediation may be a preferred method for treating tailings.

3.9 Increased Salt Budgets

Another water management issue that is a growing concern for oil sands producers is the accumulation of salt as more recycled water is used in place of makeup (fresh) water. This is especially true for in-situ producers using steam-assisted gravity drainage (SAGD) systems; an average producer can generate 33 million pounds of dissolved salts and water-solvent carcinogens annually.⁷⁸ As the salt concentration in recycled water increases, it gradually reduces the efficiency of the bitumen extraction process. With the amount of makeup water being reduced, the concentration of chloride and divalent ions in the recycled water will continue to rise. Eventually, the extraction recovery process may become impaired to the point where the recycled water needs to undergo some further form of treatment.

According to the study by Natural Resources Canada, technologies are available for this purpose, but they are expensive and have not yet been proven for processing water in hydrocarbon-contaminated oil sands.⁷⁹ One option involves treatment of ionic components in recycled water while maintaining zero water discharge. Dissolved salts are extracted in this process and shipped to landfills. However, organic contaminants also present in the recycled water interfere with the removal of the ionic components. Therefore, a secondary treatment option is to remove the organic contaminants for discharge into a surface water body and allow for consecutive withdrawal of fresh water for makeup purposes. But this also has its drawbacks. The need for makeup water goes against the directive to reduce the use of freshwater in the oil sands extraction process. In addition, the organic contaminants removed in this process include natural surfactants that enhance the bitumen recovery process.

77. Gordon Lambert, Suncor Corp., Personal communication, May 12, 2010.

78. Ibid.

79. Ibid.

This works against the other objective of the treatment process, which is to maintain sufficient levels of bitumen recovery in recycled water. Accordingly, the preferred solution would avoid this secondary treatment, but it compounds the primary challenge of reducing the salt build-up in recycled saline water. In effect, in-situ producers are caught in a “catch-22” when it comes to treatment of saline water.

3.10 Tailings Remediation Costs

The replacement of oil sands overburden and re-vegetation is not a complex issue, and the costs are well-documented. For example, in 2006 Syncrude spent a total of CAD \$30.5 million on reclamation activities on 267 hectares (ha), which works out to about CAD \$114,000/ha.⁸⁰ Another estimate relates to the re-vegetation only, at CAD \$200,000/ha, based on 10 plants per square meter at CAD \$2/plant.⁸¹

To put these figures in perspective, we reviewed the asset retirement obligation (ARO) of Suncor, which is an oil sands operator that provides ARO disclosure specific to its mining operations. Suncor’s total land impact is 12,800 ha⁸², and hence Suncor’s 2008 undiscounted asset retirement obligation of CAD \$3.49 billion works out to \$271,000/ha of disturbed land. This leaves CAD \$71,000/ha for remediation activities other than re-vegetation, including treatment of tailings on 36%, or 4,600 ha, of its impacted land.

In contrast to re-vegetation costs, tailings treatment is not a straight-forward matter. Our review of publicly available information found no references to such costs. Overall, transparency is lacking from the industry with respect to detailed aspects of tailings management options, including existing costs (in the case of CT at Suncor and Syncrude) and estimated costs. This makes it difficult to estimate compliance costs of final tailings remediation. Required corporate disclosure associated with Directive 74 should help answer questions relating to the engineering design and timetables for progressive reclamation; however, exact costs will be kept confidential by operators. Accordingly, investors may wish to request more detailed cost information on existing tailings management operations, such as CT, MFT drying, and CO₂ injection, and possibly new treatment options such as bioremediation.

In any event, there is growing recognition that the final costs of tailing reclamation will be high. For example, industry groups such as CAPP and the Alberta Chamber of Resources lobbied extensively against the introduction of wetlands protection by the Wetlands Policy Project Team in the summer of 2008, citing costs in the billions of dollars. This is not surprising, as wetlands are complex ecosystems to restore.

Because full remediation will not occur until fine tailings (FT) are settled out, no oil sands tailing pond has yet been fully reclaimed. While we could not reasonably estimate costs of CT or MFT drying, which are being developed by the operators in-house, these processes may not be able to achieve the objectives of Directive 74 in any case (although Suncor’s new proprietary method intends to do so). If the ERCB forces oil sands producers to expedite remediation of existing tailings ponds where deposits have ceased and to progressively recycle tailings liquids, these companies are likely to see:

80. Jennifer Grant et al., “Oil Sands Reclamation: Fact or Fiction?”, Pembina Institute, Mar. 2008, p.44.

81. Ibid.

82. ERCB, 2008.

Directive 74 will add to the operating costs and Asset Retirement Obligations of oil sands mining operators.

- an increase in asset retirement obligations (ARO), and consequently balance sheet leverage, as more expensive technologies are expected to speed up solidifying the FT and the timeframe is likely to be more condensed, perhaps to as little as five years. This means that there would be less time for the liability to accrue on the balance sheet in comparison with the 20-40 years that is typical for most oil sands reclamation;
- an increase in operating costs, and hence income statement impact, associated with recycling water on a going-forward basis; these higher operating costs are likely because the ERCB is intent on progressive remediation, which means much faster recycling of the FT liquids.

Costs of bioremediation: Our analysis concludes that bioremediation is a preferred treatment option because it treats wastewater early in tailings discharge, reduces sedimentation time and eliminates the need for long-term pond storage. This method also helps resolve toxicity issues and the risk of downstream and underground water contamination.

Because bioremediation has not been used extensively in the oil sands industry, its costs are not generally included in existing AROs or operating cost structure. Accordingly, we sought tailings treatment cost estimates from experts that perform bioremediation services in other segments of the petroleum industry. Our research indicates that bioremediation costs will be in the CAD \$15 to CAD \$50/ton range for the existing solid tailings (i.e., ARO effect), while ongoing operating costs could experience a CAD \$1.25 to CAD \$4.17 per cubic meter (or CAD \$1.46 to CAD \$4.86 per ton) increase if progressive remediation/recycling is required (i.e., operating cost effect). In terms of per boe production costs, the operating cost increase would be in a range of CAD \$1.21 to CAD \$4.05 per barrel of production.

The high-end figure of CAD \$50/ton for solids remediation cost (i.e. ARO effect) is broadly accepted within the industry, while the low end comes from consultation with a bioremediation expert, Fiton Technologies.⁸³ This low-end quote assumes that Fiton Technology's proprietary biocatalysis process, when applied to existing tailings accumulations, would produce economies of scale and drop the remediation cost to CAD \$15/ton.

For the progressive liquids remediation (i.e. operating cost effect), we again used quotes from Fiton to produce a low- and high-end estimate. We believe there could be a significant drop in the progressive/ongoing costs of waste remediation per unit of production because it is easier to treat the waste as it comes out of the plant, as opposed to dealing with decade-long waste accumulations. Some of the equipment and infrastructure to help the progressive treatment process already is in place on some sites. The tailings would need to be only handled once as they come out of the waste pipe, and less treatment product would be required to penetrate the newly produced, fluidized mixture. Once the waste accumulates, it becomes harder to recover and recycle water, and more bioremediation agents need to be introduced into the tailings material to treat the contaminants.

We regard these cost estimates to be conservative, given the precedent from clean-up of tar contamination at the Sydney Tar Pond. This clean-up of 700,000 tons of

83. <http://www.fiton.com>

contaminated soil cost a total of CAD \$400 million works out to CAD \$570/ton,⁸⁴ or 11 times higher than our high-end soil remediation estimate.

To calculate ARO obligations of individual oil sands miners that need to remediate existing tailings, we reviewed four projects with tailings accumulations that are as much as 40 years old. Through filings with regulatory agencies obtained by the Pembina Institute, we derived information in Figure MM for these producers as of May 2008.⁸⁵

Figure MM. Tailings Inventory (as of May 2008)

	Tailings Area (hectares)	% of impact	Tailings Inventory (m ³)	Tailings Inventory (in bbls)	Tailings Inventory (tons)
Syncrude	7,100	55%	393,230,769	1,759,858,990	337,427,974
Suncor	4,600	35%	254,769,231	1,140,190,332	218,615,307
AOSP	1,000	8%	55,384,615	247,867,463	47,525,067
CNR	300	2%	16,615,385	74,360,239	14,257,520
Total	13,000		720,000,000	3,222,277,024	617,825,868

Source: Provincial government filings through Pembina Institute; RiskMetrics' conversions

Mining operators with the highest tailings inventories face the greatest impacts on their balance sheets.

We then applied our solid tailings bioremediation estimates per project and per producer, and compared the resulting ARO obligation to what producers currently have booked on their balance sheets. In this modeling exercise, Canadian Oil Sands Trust (COST) and Imperial Oil (IMO) are projected to have the greatest balance sheet exposure in terms of remediating existing tailings. To meet the expedited clean-up schedule under Directive 74, it is assumed that these companies would assume more liability on their balance sheets in the form of growing AROs. This would raise COST's debt-to-capital ratio by at least 10% in the low-cost scenario, and by as much as 26% in the high-cost scenario. Similarly, IMO's balance sheet leverage would increase by at least 6% and possibly as much as 17% in the respective scenarios (see Figure NN).

To estimate the operating expense of producers that stems from this progressive remediation requirement, in Figure OO we have compiled the daily tailings production estimates of the four mining projects, based on the corporate disclosure of 2007 synthetic crude production.

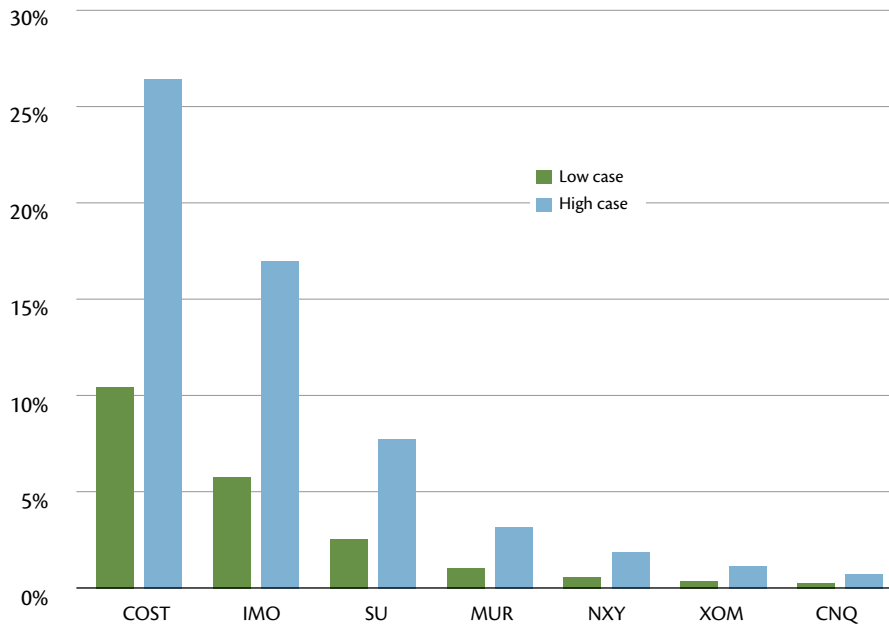
Finally, we applied our low- and high-end cost estimates for on-going tailings bioremediation to each of these producers. Figure PP shows that Suncor (SU) would experience by far the most dramatic negative impact. The increased operating expense could reduce the company's earnings in a range of 26–104%, compared to 2009 consensus earnings estimates. (These figures do not include its 2009 merger with Petro-Canada, which reduces this impact on its balance sheet. It also does not reflect SU's recent expanded investment in MFT drying operations, which the company says could speed the tailings settlement process and reduce its projected

84. See Sydney Tar Ponds Agency, <http://www.tarpondscleanup.ca/index.php?sid=2>

85. RMG's correspondence with Pembina Institute. Project-specific tailings footprint comes from digitized GIS data maintained by ERCB.

Figure NN. Projected Increase in Leverage: Debt/Capital Ratio (2010)

Source: RMG research



asset retirement obligations.) Before its merger with PetroCanada, Suncor was the largest pure-play mined oil sands producer, with the greatest volume of accumulated tailings when its participation in the Syncrude partnership is taken into account. COST, with the largest ownership stake in Syncrude, has the second-largest operating expense exposure, with earnings reductions ranging from 8–33% relative to 2009 earnings estimates, depending on whether the low- or high-cost estimate is used.

Because the other oil sands producers have smaller volumes of tailings, or are more diversified integrated oil and gas companies, their potential earnings exposure is far less than that for SU or COST (see Figure PP).⁸⁶

Figure OO. Daily Liquid Tailings Production (2007)

Oil Sand Partners	Liquid Tailings (m ³ /d)*
Syncrude	296,455
IMO (25%)	74,114
COP (9%)	26,681
MUR (5%)	14,823
SU (12%)	35,575
NXY (7%)	20,752
COST (37%)	109,688
Nippon (5%)	14,823
SU	192,359
SU + SU Syncrude	227,934
AOSP	133,939
RDS (60%)	80,363
CVX (20%)	26,788
MRO (20%)	26,788
XOM (70% of IMO)	51,583
CNQ	42,309

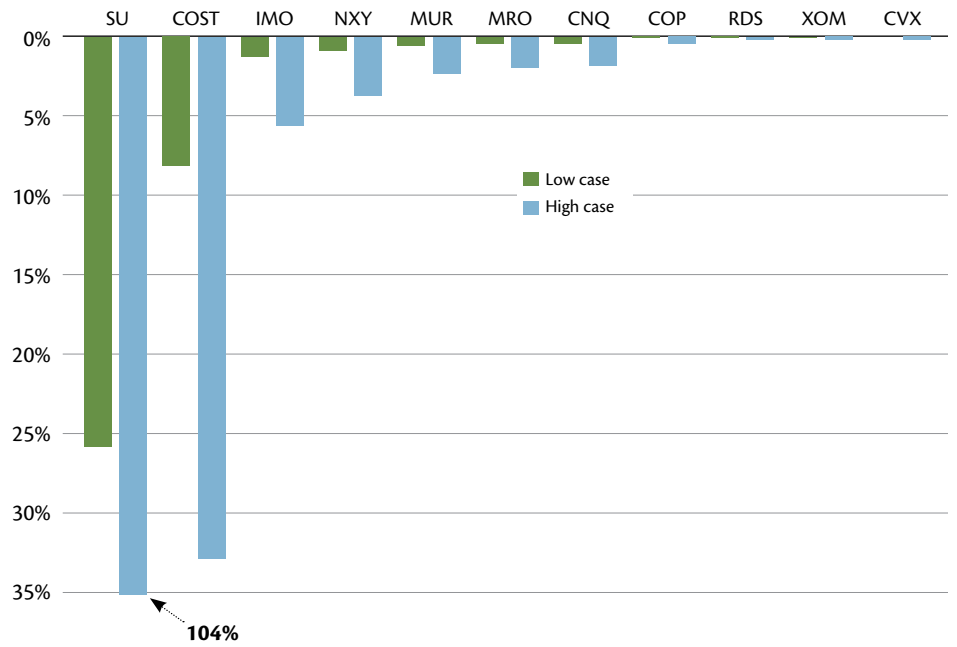
Source: RMG research

86. Detailed calculation tables are available in the Oil Sands Tailings Pond Remediation Costs Understated, a joint ESG Analytics – CFRA report published by RiskMetrics Group on Dec. 22, 2009.

Suncor and COST could see their earnings decline substantially if they don't find new solutions to treat tailings.

Figure PP. Estimated Decline in Net Income (2009)

Source: RMG research



4. Aboriginal Rights and Oil Sands Development

4.1 Historical Background

A growing concern to investors in the oil sands is the industry's tenuous relationship with local indigenous communities in Canada. Virtually all oil sands companies operate in areas overlapping with Aboriginal traditional territories.

The Canadian government signed a number of treaties with Aboriginal communities (known in Canada as First Nations, Métis and Inuit) during the 19th century that secured the oil-rich land for the Crown Domain of the Dominion. These treaties, dating back to 1876, guaranteed these Aboriginal communities the right to conduct their traditional lifestyles on these lands, namely the basic rights to sustain their livelihoods through hunting and fishing. The Canadian Constitution, signed by the Prime Minister Pierre Trudeau and the Queen of Britain in 1982, reinforced these treaty protections.

4.2 Interpretation of Indigenous Rights

In practice, Canada's Constitution requires that the national and provincial governments have the duty to *consult and accommodate* the recognized rights of Aboriginal communities.⁸⁷ Aboriginal leaders in the region have passed joint resolutions calling for a moratorium on oil sands project approvals until strategic watershed and land use planning is completed, and committing "to take all steps in our power to protect our lands, sustain our communities and assert our rights."⁸⁸ Oil sands producers have no formal role in resolving this dispute, as this requires nation-to-nation negotiations between the Crown (Canada and Alberta) and the Aboriginal communities involved. Nevertheless, oil sands producers can help their cause by being proactive in Aboriginal engagement.

A recent survey of 11 oil sands producers shows mixed results in this regard.⁸⁹ Only about a third recognize treaty rights in their Aboriginal policies, and none incorporate the principle of Free, Prior and Informed Consent (FPIC). FPIC is a core principle in First Nations' expectations of consultation. It describes respecting the right of Aboriginal people to be fully informed about exploration, development and closure activities on a timely basis, to approve operations prior to commencement, and if necessary to refuse consent. Although FPIC is not yet in widespread practice, it offers the most robust strategy to mitigate the risks of Aboriginal opposition to oil sands projects.

Aboriginal communities are granted substantial protection and rights under the Canadian constitution.

87. For more on the precedent that describes the right to consult and accommodate, see: Haida Nation vs. British Columbia <http://www.canlii.org/en/ca/scc/doc/2004/2004scc73/2004scc73.html>

88. "First Nations demand oil sands moratorium," Edmonton Journal, Aug. 18, 2008; "First Nations communities prepare for battle over water, culture," Fort McMurray Today, Aug. 27, 2008.

89. "Lines in the Sands: Oil Sands Sector Benchmarking," Northwest & Ethical Investments published by Ceres, Nov. 2009.

4.3 Legal Cases

Given the extent of environmental degradation in the region and the health impacts on local communities, the Aboriginal people have a strong case that they are being prevented from exercising their rights to traditional lifestyles guaranteed to them by the Canadian Constitution. The communities below have gone to court to fight for their right to a subsistence livelihood:

- Fort Chipewyan First Nation
- Mikisew Cree Nation
- Beaver Lake Cree
- Tsuu T'ina Nation
- Samson Cree Nation

Legal challenges to oil sands projects are growing.

These cases focus primarily on land rights and titles. The amount of toxicity or other environmental impact is irrelevant, once it passes the threshold of impeding traditional lifestyle. The major legal challenge, in other words, is to provide evidence showing abridgement of these rights. Once it is established that the community is being prevented from exercising its rights to hunt and fish, the extent of environmental damage caused by oil sands operations on these lands is largely immaterial.

These legal cases do not involve claims to the land for commercial purposes, because the First Nations and Métis do not possess these rights. The majority of the cases are filed against the provincial and federal government over failed consultation with the community, although in several instances the legal cases also name corporations as defendants in the failed consultation. In 2008 alone, three legal challenges were filed in courts by the First Nations over failed consultation.

Of note is a legal precedent set by the law firm of Jack Woodward – Woodward & Co in Victoria, British Columbia, brought on behalf of the Tse Keh Nay community in 2008. As noted in Chapter 3, the court found in this case that a flawed environmental impact assessment (EIA) process was used in connection with proposed tailings disposal into the community's Amazay Lake.⁹⁰ Although the case was brought against a Canadian gold miner, Northgate Minerals, it demonstrated the impact that First Nations can have using the Canadian legal system.

Also, in March 2008, the Beaver Lake Cree Nation filed a lawsuit against the government of Alberta, calling for an injunction to block more than 16,000 permits related to lands that are used for hunting and fishing and that have been disturbed by oil sands projects. Consequently, in February 2009, the Co-operative Bank (UK) announced that it would provide \$71,000 to fund evidence-gathering for this case.

Our meetings with lawyers in the fall of 2009—Barry Robinson, Ecojustice (formerly Sierra Legal Defense Fund), and Drew Mildon with Woodward & Co.—found that several other social activist organizations, such as Oil Sands Environmental Coalition, Ducks Unlimited and EcoJustice have challenged the Crown's and producers' due diligence as they embarked on licensing and operating their oil sands projects. The Ducks Unlimited case has gathered particularly negative publicity for Syncrude, which

90. See: Tse Keh Nay website, (VRI) <http://tsekehnay.net/index.php?/amazay>

is pleading not guilty to a CAD \$800,000 criminal charge imposed for 1,000 migrating ducks that became trapped and died in a Syncrude tailings pond in April 2008.⁹¹

Successful litigation in the above-mentioned cases could produce a setback for producers, ranging from project delays to outright invalidation of leases and project shut-downs. It could also jeopardize efforts to build new oil sands pipelines to Canada's west coast to open up new export markets. As noted in Chapter 1, nine Coastal First Nations governments announced their opposition to the Northern Gateway pipeline proposed by Enbridge Corp. in March 2010. This would be the first pipeline to bring oil sands production from Alberta to port terminals along the British Columbia coast. The First Nation groups cited concerns over the possible lasting and devastating effects of an oil spill, and said that the Athabasca Chipewyan Cree First Nation located near Alberta's oil sands backed their declaration.

First Nations governments oppose a new pipeline that would bring oil sands production to port terminals on Canada's west coast.

4.4 Failed Stakeholder Consultation

Oil sands producers have several ways in which to engage Aboriginal communities in their project development activities. The most basic of these is a Memorandum of Understanding (MOU) that outlines basic parameters for their relationship and commits both sides to discussing a commonly identified set of objectives. A signed MOU is not necessarily an indicator of community support for a project, however, but merely a signal that substantive discussions will place. A more engaging process is an Impact and Benefit Agreement (IBA) that spells out the responsibilities of the company to mitigate project impacts and deliver project benefits (e.g., revenue sharing, procurement and employment opportunities). In return, the community may provide consent provisions that are a strong indication of ongoing project support.

Stakeholders in Alberta have set up several elements that foster the progression of the consultative process, including the Alberta First Nations consultation guidelines⁹² and All Parties Core Agreement (APCA).⁹³ The APCA is an effort to bring together impacted First Nations and industry representatives for meaningful dialogue around development issues. Five First Nations of the Athabasca Tribal Council are receiving funding support for Industry Relations Corporations (IRCs) to identify key concerns about development in their traditional territories and represent those concerns effectively in consultations with the oil sands industry.

Some previously established stakeholder consultation efforts have encountered difficulties. A prime example is the Cumulative Environmental Management Association (CEMA), a group created in 1999 to address environmental issues surrounding oil sands development in Alberta. It is comprised of more than 40 stakeholders, including businesses, indigenous groups, environmental groups and government officials.⁹⁴ In February 2008, the group submitted a letter requesting a partial moratorium of oil sands production covering approximately one-sixth of the Athabasca oil sands region. However, upon review, this letter was not acted on by the Alberta Department of Energy.

91. John Loring, "Alberta's Tar Sands and the Dead Duck Trial," *Green Ink*, Mar. 10, 2010. <http://greeninc.blogs.nytimes.com/2010/03/10/albertas-tar-sands-and-the-dead-duck-trial/>

92. See: <http://www.aboriginal.alberta.ca/571.cfm>

93. See: Athabasca Tribal Council, <http://ryanjanvier.com/atc/about-atc>

94. See: <http://www.cemaonline.ca/>

Some CEMA members are oil sands producers that voiced disagreement with the letter. For example, ConocoPhillips, a CEMA member, said in a statement that it is “supportive of the general intent expressed in the letter that was submitted by CEMA,” but that existing lease-holders must be respected and be allowed to maintain the rights to develop currently held leases. “We share some of these concerns along with a number of other members of industry,” the company statement said.

In August 2008, three of the main NGO supporters of CEMA—the Pembina Institute, the Toxics Watch Society of Alberta, and the Fort McMurray Environmental Association—pulled out of the association. In a press release, these organizations asserted that after “eight years of effort and consistent failure to meet deadlines for recommending systems to protect the region’s environment, CEMA has lost all legitimacy as an organization and process for environmental management in the oil sands.”

4.5 Summary of Legal Risks

Given the deteriorating relationship among oil sands stakeholders and the growing number of legal actions taken by First Nations in Alberta and British Columbia, the risks of unfavorable court rulings for oil sands producers are increasing. While the outcome of future court rulings remains to be determined, this much is clear: while other cases involving review of environmental risks generally are more qualified and involve a range of possible outcomes that oil sands producers can negotiate and possibly work through, the First Nations’ challenges lend themselves to more binary outcomes. Either a producer is able to maintain its lease and continue operating business as usual, or the lease may be annulled and the producer has to abandon the project altogether.

Accordingly, the implications of First Nations’ legal intervention loom large in the future of the Albertan oil sands industry, and bear close watching by investors.

5. Conclusions

Oil sands development is drawing increasing scrutiny from institutional investors.

5.1 Finding the Right Growth Trajectory

The ongoing controversy and unresolved questions surrounding oil sands development in Alberta have led to calls for a moratorium on new projects. A number of Aboriginal leaders in the region want project approvals put on hold until strategic watershed and land use planning is completed, and they receive assurances that they will be properly consulted with their constitutional rights respected.⁹⁵ Some Canadian investor groups, such as Northwest & Ethical Investments, based in Vancouver, British Columbia, support this call for a new-project moratorium.⁹⁶ Meanwhile, a group of investors, with backing from some major U.S., European and Australian institutions, has filed shareholder resolutions with four major oil sands producers in 2010 asking for better disclosure of the economic and environmental risks associated with oil sands development.⁹⁷ A similar resolution filed with ConocoPhillips in 2009 received strong investor support—30.3% in favor, representing \$12.8 billion in share value.

Falling oil prices in late 2008 prompted a de facto moratorium for some oil sands producers that have canceled or indefinitely deferred many new projects. However, global oil prices have since rebounded, and prospects for new oil sands development have improved. Several prominent players, including Cenovus and Suncor (which merged with Petro-Canada in summer 2009 to create Canada's biggest oil company), have signaled their intent to maintain oil sands development as a core business activity. Imperial Oil has also received a corporate go-ahead to launch a giant new mining project, and in April 2010 PetroChina International Investment launched a public offering of its 60% stake in Athabasca Oil Sands Corp.'s in-situ projects.⁹⁸

In effect, these companies are betting that demand for higher-priced oil is here to stay. To justify investments in new oil sands development, oil needs to maintain a global price of at least \$65/bbl and possibly as high as \$95/bbl. A recent forecast from the U.S. Energy Information Administration (EIA) projects that oil prices will continue to rise and reach \$130/bbl by 2030 (in constant 2009 dollars). This would raise oil sands production volume up to 4.2 mbbbl/d by 2030 under a high economic growth forecast (see Figure QQ), according to EIA. This is more than double the volume of existing operating capacity and projects under construction. This EIA estimate is also 500,000 bbl/d above the Growth scenario of 3.7 mbbbl/d that has been presented in this report. At \$200/bbl, the EIA estimates that oil sands production could reach as high as 6.5 mbbbl/d by 2030—far above any of the scenarios presented. However, we regard this as a highly unrealistic and economically and environmentally unsustainable scenario, for reasons outlined earlier.

95. "First Nations demand oil sands moratorium," *Edmonton Journal*, Aug. 18, 2008; "First Nations communities prepare for battle over water, culture," *Fort McMurray Today*, Aug. 27, 2008.

96. "Lines in the Sands: Oil Sands Sector Benchmarking," Northwest & Ethical Investments, published by Ceres, Nov. 2009.

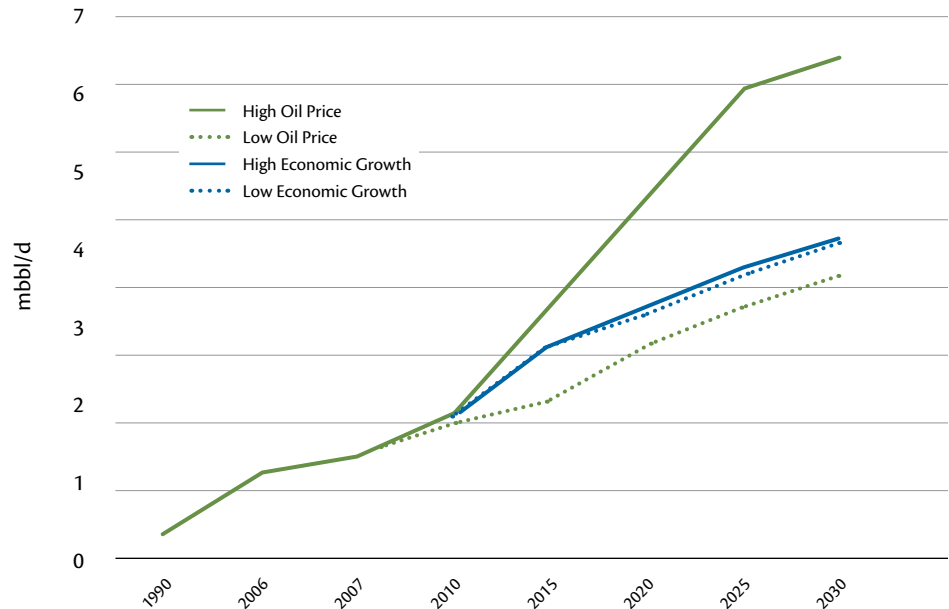
97. Hugh Wheelan, "Shareholder Abstention on Oil Sands at BP Fires Warning Shot," *Responsible Investor*, Apr. 16, 2010.

98. "PetroChina-controlled Athabasca Oil Sands to be listed on Toronto Stock Exchange," Xinhua News Agency, Apr. 2, 2010.

Figure QQ. Oil Sands Production Projections

Source: U.S. Energy Information Administration, 2010 Energy Outlook

EIA IEO 2009 Projections: Canada Oil Sands



Oil sands producers face rising floor costs and falling ceiling prices that are shrinking their window of opportunity.

5.2 Shrinking Window of Opportunity

Given such a wide range of estimates, the modeling assumptions used in this report (and the 2009 CAPP survey of oil sands producers on which they are based)⁹⁹ may be viewed as conservative. However, we believe that global market conditions may have difficulty sustaining oil prices above a range of \$120–\$150/bbl for any length of time. That is because high oil prices historically have slowed economic growth and depressed commodity prices while stimulating investments in energy efficiency and alternative fuels. Carbon emission limits expected to take hold in the next two decades also are likely to reduce global demand for oil and other carbon-intensive fuels as they add to their price.

Accordingly, oil sands producers are operating in a narrow financial window that may be shrinking over time. They want to avoid reaching an oil price ceiling, like the one at \$147/barrel in July 2008 that contributed to the oil price collapse below \$40/barrel by the end of that year. But they also want to be confident of an oil price floor—now estimated at \$65–\$95 per barrel—to justify such long-term, capital-intensive investments. Oil markets have rarely maintained such stability and orderly price movements; this is one of the inherent risks in investing in this volatile commodity.

Beyond global market conditions, oil sands producers must also be wary of their own rising production costs. A combination of growing demand for natural gas, onset of carbon pricing and low carbon fuel standards will effectively raise the floor price for production of synthetic crude oil. Growing water requirements and land

99. "Crude Oil: Forecast, Markets & Pipeline Expansions," Canadian Association of Petroleum Producers (CAPP), 2009.

reclamation regulations will add on another layer of additional costs. The biggest wild card, however, may be relations with First Nations and other Aboriginal communities whose exercise of constitutional rights has the potential to stop some oil sands projects and pipelines dead in their tracks.

This report has addressed each of these risks. We conclude that oil sands producers banking on rapid growth are taking a big gamble. Over the long time horizon of these capital-intensive investments, market and energy policies could turn against their projects for reasons largely beyond their control. This argues for a more incremental approach that allows market signals to become clearer, carbon risks to be examined more thoroughly, and technologies and mitigation strategies to evolve so that risk exposures are limited and better managed. To the extent that the oil sands industry is moving from traditional, mega-style mining projects to more modular in-situ projects, this more reflective, incremental approach may already be evolving.

Nevertheless, there is good reason to believe that oil sands producers fully intend to step up the pace of development as long as they believe market forces will support further expansion. Investors should be concerned and asking questions on whether such strategies lose sight of longer-term risk issues that may ultimately compromise oil sands projects. Accordingly, we offer this summary of the major risks that oil sands companies and their investors must be prepared to address.

5.3 Natural Gas

Oil sands have a low energy return on energy invested (EROEI). With an EROEI of 7:1 vs. 22:1 for conventionally produced oil, it takes three times more units of energy to extract bitumen from oil sands than oil from conventional wells. After upgrading and refining, the EROEI of oil sands falls even further to just 3:1.

Natural gas is the primary fuel used throughout the oil sands extraction and upgrading process, with in-situ producers especially reliant on steam for injection into deep underground deposits. By 2015, oil sands producers' demand for natural gas could triple, accounting for 15% of Canada's consumption of this clean-burning fossil fuel. However, there will be many competing demands for natural gas, as carbon pricing increasingly favors use of this low-carbon fuel for power generation and transportation. As a result, oil sands producers face the risk of higher purchasing costs for this key energy input. At the same time, more pipeline infrastructure will be needed to deliver the ever-growing quantities of natural gas that oil sands producers require.

For forward-looking investors, a key metric to track is the steam-to-oil ratio of in-situ projects. Some producers like BP claim that future technological improvements will enable new projects to achieve a better than 2:1 SOR, meaning less than two units of steam would be needed for each unit of bitumen produced. This compares with a current average of approximately 3:1 SOR for operating projects in the Athabasca deposit. A declining SOR would have multiple benefits, as it would reduce the amount of natural gas and water required to produce the steam, and limit exposure to the costs of water recycling and any future restrictions on absolute water use. However, SORs from operating projects are often higher than their design SORs. Several new projects have design SORs of 7:1 or 8:1 due to the deteriorating quality of in-situ deposits, with greater amounts of steam and energy required. Accordingly, investors who gain access to SOR data would be better able to determine whether in-situ producers are facing rising or diminishing returns with their new projects.

Oil sands producers' demand for natural gas competes with other uses of this clean-burning fuel.

Carbon emissions from Alberta's oil sands could triple by 2030.

5.4 Carbon Emissions

The large energy requirements of Canada's oil sands producers also make them prodigious emitters of carbon dioxide, the principal manmade source of greenhouse gas emissions. The oil sands industry is Canada's fastest growing source of GHG emissions, with its emissions projected to grow from 5–15% of the nation's total by 2020. At the same time, Canada, like other industrial nations, has pledged to reduce its GHG emissions substantially over time, perhaps by more than 80% by 2050. This puts the oil sands industry on a collision course with this key, long-term national objective.

Short of curtailing production, oil sands producers have relatively few options to reduce their GHG emissions. Some extraction techniques, such as toe-to-heel air injection (THAI), have the potential to reduce dependence on natural gas for steam production; but this is still an experimental production technique. Nuclear power is another possible replacement for natural gas, but no oil sands producers have current plans to pursue this option. That leaves carbon capture and sequestration (CCS) as one of the only remaining technological solutions to reduce the industry's growing GHG emissions.

Since 2007, the Province of Alberta has placed a CAD \$15/ton levy on CO₂ emissions and made CAD \$2 billion available to support commercial demonstration of CCS technology. However, these measures to date have prompted only one oil sands producer, Shell Canada, to move forward with a CCS demonstration project. Few portions of oil sands production yield sufficient concentrations of CO₂ to make the process economic. Even these are expensive solutions that capture only 10-30% of the entire CO₂ waste stream. Alberta's CCS Task Force estimates that the initial cost of CCS at oil sands upgraders and hydrogen facilities is in a range of about CAD \$75-\$115/ton of CO₂, taking into account a \$15–20/ton levy on CO₂ emissions.¹⁰⁰

Moreover, Alberta's oil sands are not in an ideal geographic location to support carbon sequestration. Extensive pipeline networks would have to be built to ship the CO₂ to underground reservoirs located up to 1,000 miles away. A host of legal, regulatory and permitting issues also still have to be overcome. Liability issues present a particular challenge, since the sequestered carbon would need to remain safely stored underground for hundreds or even thousands of years.

Even if the oil sands industry eventually achieves a higher CO₂ capture rate of 30-50% by 2050, the remaining upstream emissions from growing rates of production could exceed the entire carbon budget for all of Canada if the government remains intent on an 80% cut in total emissions by 2050.¹⁰¹ This also means that Canada would need a substantial pool of carbon offsets to bring oil sands producers' emissions in line with these national targets. It is unclear whether a carbon trading market in Canada could emerge fast enough and grow large enough to address these excess oil sands emissions.

100. "Accelerating Carbon Capture and Storage in Alberta," Alberta Carbon Capture and Storage Development Council, Oct. 2008.

101. "Carbon Capture and Storage in the Alberta Oil Sands — A Dangerous Myth," World Wildlife Fund and The Co-operative Bank, Oct. 2009. [The referenced projection for 2050 assumes that Canadian oil sands production reaches 5.8 mbb/d at that time.]

All of this leaves critical, unanswered questions for investors. These include whether oil sands companies are:

- placing an assumed price on oil and carbon emissions in their production forecasts
- projecting future prices and availability of locally sourced natural gas
- investing in R&D and new technologies to reduce carbon emissions, including CCS
- making plans to purchase credit allowances to offset their carbon emissions
- supporting the creation of a large carbon trading market with affordably priced offsets
- setting explicit targets and timetables to reduce the GHG intensity and overall emissions of their operations

5.5 Low Carbon Fuel Standards

In addition to limits that may be placed on upstream CO₂ emissions from oil sands production, limits may also be placed on downstream CO₂ emissions when the fuel is burned. Such limits are likely to be in the form of Low Carbon Fuel Standards (LCFS). More than half of the U.S. states and four Canadian provinces are weighing the adoption of LCFS to reduce the carbon intensity of some petroleum fuels. California already has an LCFS in place that requires a 10% reduction in the average carbon intensity of motor vehicle fuels by 2020; the Northeast may soon follow suit. Together, these states comprise one-quarter of U.S. demand for transportation fuels.

Adoption of LCFS would place oil sands producers at a disadvantage to conventional petroleum producers, because their synthetic crude oil (SCO) is 12% more carbon-intensive on a “wells to wheels” basis than gasoline. That means oil sands suppliers would need to achieve a 20% total reduction in carbon intensity over the next decade in order to comply with an LCFS based on the California standard. Options include increasing the use of electricity, natural gas and low-carbon renewable fuels in the overall transportation mix.

Offset allowances permitted within the transportation sector could create a market for LCFS credits that would help oil sands producers comply with these rules. We estimate that a \$100/ton price for such LCFS credits would effectively raise the price of SCO by \$11.40 per barrel to meet an LCFS standard with a 10% carbon-intensity reduction target (equal to a 20% reduction for synthetic crude). However, because conventional gasoline producers would also be in the market for LCFS credits, and need proportionately fewer credits to meet LCFS requirements, they would be the likely drivers of this market. This may leave oil sands producers with only the most expensive LCFS purchase options—or possibly no credits at all.

A related government policy goal is to increase the production of advanced renewable fuels with low-carbon content, such as cellulosic ethanol, so that it can be blended with petroleum to meet the LCFS. However, it is possible—perhaps even likely—that the ambitious targets set forward by the U.S. Congress for 36 billion gallons of advanced biofuels production per year by 2022 will not be met. In the unlikely event that no options emerge for Canadian oil sands producers to comply with a federally adopted LCFS—including no use of blended renewable fuels or other offsets through trading systems—the U.S. transportation market could conceivably disappear for Canadian oil sands producers. This worst-case scenario would leave oil sands

Low Carbon Fuel Standards could cut demand for oil sands production in half.

producers with less U.S. demand in 2030 than the estimated 2 mbb/d of production estimated under the Operating and Construction scenario discussed in this report—possibly eliminating further expansion of oil sands production in the decade ahead.

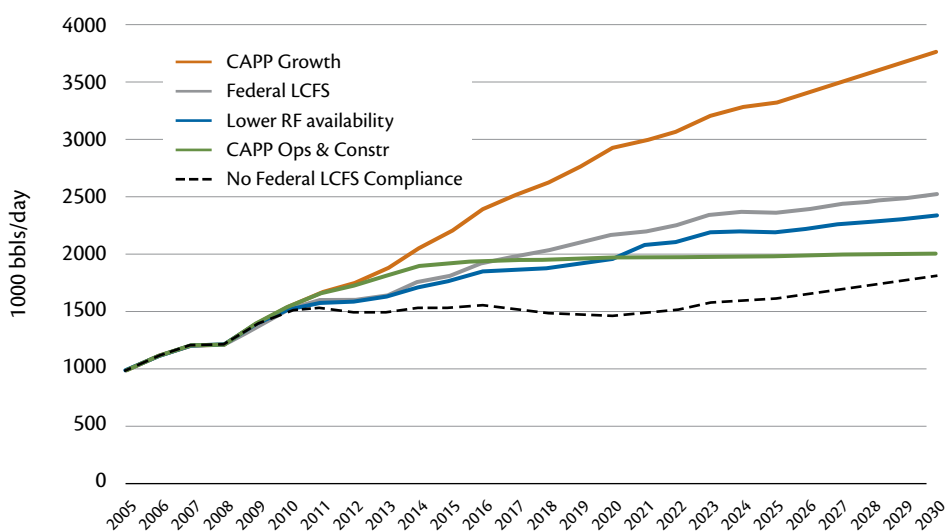
If the advanced renewable fuel targets are met, however, oil sands producers would have more justification to expand production. This result is somewhat counter-intuitive: even though more renewable fuels would be available to displace gasoline and synthetic crude oil in motor fuels, they would also reduce the overall carbon intensity of blended motor fuels; hence, more carbon-intensive SCO from oil sands could be added as part of an LCFS-compliant fuel mix. This means oil sands producers have a strong incentive to see the renewable fuels market grow and flourish.

That said, the adoption of LCFS standards still would have a negative impact on projected oil sands production under any scenario considered in this report. For example:

- A U.S. federal standard that seeks a 20% reduction in the carbon intensity of transportation fuels could eliminate 1.2 mbb/d of oil sands production by 2030—a 33% reduction relative to the CAPP Growth forecast (from 3.7 mbb/d down to 2.5 mbb/d).
- If a proposed federal LCFS standard is held at a 10% reduction after 2020, the estimated reduction in oil sands production would be limited to 0.9 mbb/d, with production at 2.8 mbb/d.
- If only certain regions of the United States adopted an LCFS with a 20% reduction in carbon intensity through 2030, estimates of oil sand production would vary accordingly. For example, if half of the U.S. motor fuels market adopted this standard, we project that oil sands production volume would reach 2.95 mbb/d in 2030. Production would rise to 3.2 mbb/d if only California and the Northeast, representing a quarter of the U.S. market, adopted such an LCFS. In this last instance, production volume would decline 13.5% relative to the CAPP Growth forecast.

Figure RR. Oil Sands Production Comparisons (mbbl/d)

Source: RiskMetrics Group, referencing CAPP production forecasts



Accordingly, investors must watch carefully as low-carbon and renewable fuel standards are implemented regionally and possibly federally in the United States and Canada. One outcome might be that oil sands producers look to other markets that don't impose such carbon-intensity limits on motor fuels. This in turn raises the question of whether they would be able to tap these markets. Prospects for such expansion appear mixed, at best. First, Canada's oil sands producers must overcome opposition from many First Nation governments that oppose development of new pipelines across their territories to port cities on Canada's west coast. Second, these producers must consider whether other export markets, principally in Asia, will also be adopting LCFS rules or other restrictions on carbon emissions in the time frame that the necessary infrastructure would be built, including refineries to process the bitumen. PetroChina's move to take a 60% stake in Athabasca Oil Sands Corporation's in-situ projects in September 2009 indicates that a possible Asian connection is still in play.¹⁰² But it does not mean that the obstacles have diminished.

Accordingly, low carbon fuel standards raise important questions for investors. These include whether oil sands companies:

- factor LCFS as a contingency in their production forecasts
- plan to invest in LCFS credits as a compliance option, and estimate the price and availability of these credits
- support investments in advanced renewable fuels, such as cellulosic ethanol, which provide an optimal blending fuel for synthetic crude oil
- are looking beyond possibly LCFS-constrained markets such as the United States to other export markets, principally in Asia, where such constraints may emerge more slowly
- consider time frame investments in new pipelines, port terminals and refineries would take shape, and the risks and obstacles to moving forward with such plans

While the spread of LCFS standards from California to other regions of the United States and Canada may be a near-term threat to the oil sands industry, it could work to the industry's longer-term advantage by promoting some mutual national policy objectives. Most existing Canadian oil sands pipelines feed into the U.S. Midwest, which has substantial infrastructure in place to process this fuel and combine it with its significant ethanol production capabilities. Building on this relationship with new investments in advanced renewable fuels would not only help achieve compliance with LCFS standards, but also spur more employment in clean technology industries and promote regional energy independence that would enable Canada and the United States to better compete against European and Asian nations as they advance their own low-carbon economies.

5.6 Water Use

Among the other potential environmental considerations in future oil sands production, water issues loom large. This is especially true for oil sands mining operations, where up to four barrels of water are consumed for each barrel of synthetic

Oil sands producers should actively support development of advanced renewable fuels.

102. "PetroChina-controlled Athabasca Oil Sands to be listed on Toronto Stock Exchange," Xinhua News Agency, Apr. 2, 2010.

Oil sands producers will need to invest more in water storage, treatment and recycling.

crude oil produced. (The ratio is below 1:1 for in-situ producers, because they rely more on recycled water from underground aquifers.) The Mackenzie River watershed in Canada faces the specter of a long-term decline in water supplies. Climate change is already shrinking glaciers that feed into the Athabasca River, the source of the water for much of Alberta's oil sands production. Some studies suggest that by mid-century regional climate impacts could reduce the Athabasca River's water flow by 50% during winter months, when the availability of water for industrial use is most restricted.¹⁰³

Water shortages for oil sands producers could emerge well before the middle of the century. Water diversions in the Athabasca River and its tributaries are already restricted during low-flow periods—typically from November through mid-April—in order to protect fish habitat. Our analysis indicates that some oil sands mining producers that are especially dependent on securing freshwater supplies could encounter wintertime cut-offs as early as 2014 as they try to scale up production. This is likely to spur significant additional investments in water storage, treatment and recycling facilities.

Accordingly, a key water metric for investors to track is the ratio of barrels of water consumed for each barrel of oil equivalent produced (boe), especially for oil sands miners. Those with a high water use rate of 4.5:1 could be subject to wintertime access restrictions by 2014 under both the Growth and Operating & Construction scenarios outlined in this report. By contrast, oil sands miners with a water consumption rate of only 2:1 should be able to maintain uninterrupted freshwater withdrawals under either scenario for the foreseeable future. However, as production rises, pressure will mount on all oil sands producers to achieve average water withdrawal ratios below 4:1 by 2020.

Another factor in the water withdrawal equation is that legacy oil sand miners received far more generous access to the Athabasca River watershed than more recent entrants. A key development to watch is whether the Albertan government will successfully renegotiate a more equitable redistribution of water withdrawal permits. So far, legacy producers have not been willing to give up their claims. At the same time, legacy producers must be mindful of competing demands by agricultural, municipal and other industrial users that want more access to this supply. In the event that climate change makes regional water shortages more acute, pressure will mount even further on these legacy miners to give up some of their claims to this precious natural resource.

In addition, oil sands producers face new provincial regulations on the measurement, use and recycling of water. The regulations seek more recycling of water drawn from underground aquifers, and give preference to use of saline rather than freshwater. Saline water that is not recycled would have to be treated, adding to total water management costs. As a result, in-situ producers who rely more on underground aquifers could face water treatment costs matching those of mining producer who draw mainly on surface, freshwater supplies—in both cases reaching as high as 5% of total operating costs.¹⁰⁴

103. David Schiller and Vic Adamowicz, "Running Out of Steam? Oil Sands Development and Water Use in the Athabasca River-Watershed: Science and Market-Based Solutions," University of Toronto, Munk Centre, May 2007.

104. Len Flint, "Bitumen Recovery Technology, A Review of Long Term R&D Opportunities," Lenef Consulting Limited, Jan. 2005.

In summary, the large-volume water requirements by oil sands producers place a particular need on responsible water management. Seasonal changes in water availability make it especially important that mining producers invest in water storage and recycling. In-situ producers—while facing fewer water supply requirements overall—still need good-quality water for steam generation. This results in higher costs of water treatment from various sources, including from underground saline aquifers.

Water treatment is tied to ultimate reclamation of tailing ponds, another contentious issue with high potential costs down the road. Land reclamation issues are summarized in the next section.

5.7 Land Reclamation

Land reclamation and water treatment issues are inextricably linked in Alberta's oil sands. Boreal forests in the Athabasca River watershed have been cut down and fragmented by oil sands production, turning much of the area into an industrial wasteland. In the process, one of the world's cleanest environments now poses a potential threat to public health.

Oil sands mining operations are especially visible on the landscape, as trees are cleared and topsoil scraped away to expose sands laden with bitumen. Water drawn from the Athabasca River helps transport this sand to treatment facilities, where the combination is heated to separate bitumen from the sand. The bitumen undergoes further treatment to become synthetic crude oil. The remaining water and toxic petroleum slurry is deposited in tailings ponds, where it takes decades to separate the remaining clay from the water in which it was transported and processed.

In-situ operations have less impact on the surface, since they inject steam deeper underground to bring bitumen to the surface. But they have a much broader footprint across the boreal forest, with production facilities and pipelines fragmenting it into many parts. In-situ production also requires large volumes of natural gas that add to the carbon-intensity of the process. Produced waste liquids are mainly re-injected underground, but some surface water withdrawals and wastewater treatment are also required.

As of mid-2009, more than 530 square kilometers of land (equal to 53,000 hectares) were disturbed by oil sands mining activity in Alberta, an area the size of Delaware.¹⁰⁵ Approximately 3.1 million barrels (597,000 tons) of sediment have been spread out in tailings ponds over 13,000 ha, or one-quarter, of this landscape. These tailings ponds extend over an area roughly the size of Washington, D.C. This toxic mixture of water, sand, clay, residual bitumen, organic contaminants, salt and trace metals is growing. Left alone, it will take decades to process these tailings into reusable soil and clean water.

In 40 years of oil sands production, no tailings ponds have yet been fully reclaimed. That is because, while mature fine tailings settle out after three to five years, the fine tailings remain suspended. As a result tailing ponds could substantially alter the surrounding ecosystem by contaminating soil and water sources, presenting both health problems to downstream communities and the potential of a catastrophic

Land reclamation remains one of the biggest financial and environmental challenges facing oil sands producers.

105. Government of Alberta, <http://www.energy.gov.ab.ca/OilSands/791.asp>.

breach. This issue is one of the oil sands industry's biggest long-term environmental challenges, especially for legacy oil sands miners like Suncor and Canadian Oil Sands Trust.

As discussed in Chapter 2, Alberta's Energy Resources Conservation Board (ERCB) is tightening oil sands tailings management under Directive 74. This directive requires mined oil sands producers to remediate existing tailings ponds, where disposal has been completed, within five to eight years, and progressively recycle more tailings in the future. Because fine tailings (FT) take as long as 40 years to settle, and current technology is not yet able to expedite this process, companies may be forced to use alternative processes such as bioremediation or Suncor's proprietary MFT drying and accelerated dewatering process to meet the schedule set by the ERCB.

Bioremediation as a wastewater treatment option offers several advantages. By treating wastewater early in tailings discharge, it reduces sedimentation time and the need for long-term pond storage. This method also helps to solve toxicity issues and reduces the risk of downstream and underground water contamination. Bioremediation is still expensive, however, even under the optimistic modeling assumptions used in this report. If bioremediation were used to treat new tailings production, our analysis indicates that Imperial Oil could see a 6-17% increase in its debt-to-capitalization ratio, and Canadian Oil Sands Trust (COST) could see a 10–26% increase, in order to cover the added asset retirement obligations for existing tailings sands projects.

Taken together, water management and land reclamation are major issues that get minimal attention on oil sands producers' balance sheets. Accordingly, investors should consider the following questions to oil sands producers on this topic:

- Do oil sands producers track and report on water use from the Athabasca River and underlying Mackenzie River watershed?
- What strategies do they have in place to reduce water withdrawals from this watershed?
- Will legacy producers with more generous water allowances be forced to give up a portion of their future supply to new entrants?
- Are possible reductions in water supply from climate change being factored into these decisions?
- What current water-to-oil production requirements are needed for specific mining and in-situ projects?
- What water reduction targets are being set for the future, including increased recycling rates for fresh and saline water?
- What other cumulative impacts of oil sands production are being measured and assessed, such as air quality, human health and biodiversity impacts?
- With respect to tailings reclamation, how will Directive 74 affect operating costs and asset retirement obligations (ARO) of oil sands operators?
- More generally, how will oil sands operators reflect the costs of water treatment, land and air reclamation on their balance sheets as part of publicly disclosed risk management plans?

5.8 Aboriginal Consultation

As oil sands producers look to expand their operations in Alberta, they need to address growing concerns about a lack of clear land use plans and water management strategies, especially in regard to overlapping Aboriginal territories whose communities may be affected. Under Canada's Constitution, these Aboriginal communities have a right to conduct their traditional lifestyles and sustain their livelihoods through hunting and fishing. The national and provincial governments of Canada have a duty to consult and accommodate these recognized Aboriginal governments as new developments are proposed in their territories.

To date, this has not happened to the satisfaction of some Aboriginal leaders. They have passed joint resolutions calling for a moratorium on new oil sands project approvals until proper engagement and consultation takes place. This includes Coastal First Nations in British Columbia that announced their opposition to a proposed pipeline that would link Alberta's oil sands producers to port terminals on Canada's west coast. This raises the specter of protracted court battles and possible annulment of leases that could compromise the oil sands industry's expansion plans. For obvious reasons, this is a highly material issue for investors.

At least five Aboriginal territories have brought cases before the provincial and federal government over failed consultation with their local governments. Although oil sands producers have no formal role in resolving these disputes, as this requires nation-to-nation negotiations with the Canadian government, several cases also name corporations as defendants. Accordingly, oil sands producers may be able to help their cause by engaging more proactively with Aboriginal communities.

In a recent survey of 11 Canadian oil sands producers, only one-third recognize Aboriginal treaty rights in their corporate policies.¹⁰⁶ None incorporate the principle of Free, Prior and Informed Consent (FPIC), which is a core principle in the territories' expectations of consultation. The past track record of companies engaging with Aboriginal communities is mixed. Some acknowledge discussions but many do not report whether they have negotiated even basic agreements with any impacted communities. A new effort to bring together First Nations and industry representatives is the focus of an All Parties Core Agreement.¹⁰⁷ This provides an opportunity for more meaningful discussion around core development issues, where previous efforts have failed.

Oil sands producers' consultation and engagement around Aboriginal rights issues raises a key set of questions for investors. Important questions include whether the companies:

- disclose any risks posed by current Aboriginal rights litigation
- acknowledge any contact with Aboriginal communities or agreements they have put in place
- set policies for consultation and engagement to guide future discussions
- have defined terms for such engagement, including whether it involves Free, Prior and Informed Consent
- describe resources to be made available for these activities and for educating employees around Aboriginal rights issues

106. "Lines in the Sands: Oil Sands Sector Benchmarking," Northwest & Ethical Investments, published by Ceres, Nov. 2009.

107. See Athabasca Tribal Council, <http://ryanjanvier.com/atc/about-atc>

Aboriginal communities may increase opposition to oil sands development if their rights are not respected and their concerns are not addressed.

Investors need answers in this \$200 billion bet on oil sands.

5.9 Towards a Strategic Plan

Effective engagement with Aboriginal communities is vitally important to the future of Canadian oil sands producers. However, this issue should not be viewed in a microcosm. The same questions apply equally to investor concerns about the costs of land use reclamation and watershed management, as well as climate change and carbon mitigation goals. All of these challenges place oil sands expansion in jeopardy.

These ongoing risks also create an opportunity to step back from the gold rush mentality that characterized much of oil sands development before the oil price collapse in 2008. Oil sands producers should be reflecting on the lasting impacts that their proposed development may have on the land and water of Alberta, surrounding communities and the global environment through climate change. They should also be carefully examining how their own prospects may be affected by rising production costs, increased liabilities and changing global energy markets, which may narrow or even close the window of profitability for oil sands.

In the end, none of these considerations may change company decisions to invest further in oil sands development. But they could alter the pace and scale at which appropriate development takes place, and the willingness of companies to address these challenges as they invest in new projects. They might also give pause to companies who find that cost-effective solutions to many of these challenges do not yet exist. By putting together a more comprehensive, long-term strategy in collaboration with impacted communities—one that is well-articulated to investors—oil sands producers may gain more confidence in their ambitious development plans. The alternative leaves vital questions hanging in the balance, and only raises the stakes of the multi-billion dollar gamble now taking place in Alberta's vast oil sands region.

Ore Conversion Table

Cubic Meters	bbbl	Tons
1	6.28	2.6
0.159	1	0.41
0.385	2.42	1
0.68	4.28	1.77

Composition of Feedstock (per boe)

	%	Tons	before processing	after processing
Sand	73%	1.25	3.12	4.37
Bitumen	10%	0.18	1.11	1.00
Water	4%	0.07	0.45	0.45
Fines and clay***	13%	0.23	0.55	0.55
Residual bit	0%	0	0	0.10
Total	100%	1.77	5.23	6

Conversion metrics			
Oil			
1	boe	0.1589873	m3
1	m3	35.34	ft3
1	boe	5.6	ft3
1	tonne	7.33	bbls
1	bbls	0.13643	tonnes
1	tonne	1.16538	m3
1	bbl	42.00	Usgallons
1	tonne	307.86	US gallons
1	tonne	1,165.47	litres
1	bbls	159.00	litres
Water			
1	m3	6.2898	bbl
1	bbl	0.159	m3
1	US gallon	3.8	litres
1	bbl	159	litres
1	m3	1000	litres
1	tonne	1	m3
1	bbl	0.16	tonne
CO2			
1	m3 of trees can absorbe	1.83	tonne of CO2
1	litre gasoline emits	2.36	kg
1	gallons gasoline emits	30.3	pounds
1	litre diesel emits	2.73	kg
1	gallon diesel emits	22.5	pounds
Land			
1	km2	100	hectars
1	ha	100*100	meters area
1	km2	1000*1000	meters area
Tailings			
1	bbl	0.191735801	tonnes
1	bbl	223.4623245	litres
1	bbl	0.223444476	m3

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