An IHS CERA Special Report

Growth in the Canadian Oil Sands:

Finding the New Balance

CERA

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CERA hosted a series of workshops and meetings providing an opportunity for oil sands stakeholders to come together and discuss perspectives on the key issues related to oil sands development.

Workshops were held in Calgary (November 21, 2008); Washington, DC (December 10, 2008); Fort McMurray (January 14, 2009); and Calgary (March 24, 2009). Participation in these workshops does not in any way reflect endorsement of the content of this report. CERA is exclusively responsible for the content of this report.

CERA would like to thank and recognize the following organizations who made a contribution to this report by participating in one or more of the workshops:

- Alberta Energy Research Institute (AERI)
- Alberta Energy Resources Conservation Board (ERCB)
- American Petroleum Institute (API)
- Argonne National Laboratory
- Athabasca Oil Sands Corp.
- BP Canada
- Canadian Association of Petroleum Producers (CAPP)
- Canadian Natural Resources Limited
- Canadian Oil Sands Trust
- CanmetENERGY
- ConocoPhillips
- EnCana
- Government of Alberta
- Government of Saskatchewan
- IBM Canada
- Idaho National Laboratory
- Ivanhoe Energy
- Laricina Energy
- Marathon
- MEG Energy
- MP Fort McMurray-Athabasca
- Natural Resources Canada (NRCOM)
- Nexen Inc.
- OSUM Oil Sands
- Pembina Institute
- Petrobank Energy and Resources Ltd.
- Regional Municipality of Wood Buffalo
- Resources for the Future
- Securing America's Future Energy (SAFE)
- Seven Generations Energy
- Shell Canada Ltd.
- Suncor Energy Inc.
- TD Bank
- Total E&P Canada
- TransCanada
- US Environmental Protection Agency (EPA)
- US Department of Energy
- Urban Development Institute - Wood Buffalo
- Wood Buffalo Métis Corporation (WBMC)

Report Objectives

Few natural resource developments offer such a large magnitude of potential benefits as the Canadian oil sands, the second largest reserves of recoverable oil in the world after Saudi Arabia, but development also raises significant long-term questions. This is reflected in the wide spectrum of views regarding the pace and future of oil sands development. Some argue for continued expansion, others for a slower pace or even halt to development. There are many stakeholders affected by oil sands development: local, provincial, and national governments; neighboring communities; investors; and nongovernmental organizations (NGOs).

The purpose of this CERA report is to offer a balanced assessment of the benefits, risks, and issues associated with oil sands development. This entails three specific objectives.

- **Inform.** We explain the history of the oil sands and its place in the world oil market, and provide context for the oil sands debate across political, environmental, and technological dimensions.
- **Illuminate.** A number of critical, but controversial, issues will shape the future of the oil sands. Many of these issues defy simple, clear-cut explanations. We assess these issues by identifying what is known as well as areas of uncertainty.
- **Illustrate.** We present three scenarios that describe how the future of oil sands investment and attendant issues could evolve from 2009 to 2035. The scenarios are not an attempt to identify a singular path forward. The goal is to illustrate a range of implications based on different assumptions about how the future could unfold.

Report Process

This report draws on input received from a series of workshops in Calgary and Fort McMurray, Alberta; and Washington, DC, in 2008 and 2009. Representatives of government, oil companies, local communities, and NGOs attended the workshops. CERA conducted our own extensive research and analysis and made site visits to oil sands production facilities. CERA has full editorial control over this study and is solely responsible for the report's contents.

Report Structure

This report has six chapters, including the Executive Summary.

- **Executive Summary.** This is a brief summary of the report, including CERA's Key Insights.
- **Chapter I: The Oil Sands Story.** We explain the history of the oil sands, how they are produced, their role in the oil market, and how and why matters surrounding their future development affect critical issues facing the world today, particularly energy security, climate change policy, environmental protection, and international trade and cooperation.
- **Chapter II: The Political and Social Context of Oil Sands Development.** This chapter describes the political and social issues that have an impact on oil sands development, including the US-Canada relationship, provincial regulation of development, and First Nations rights.
- **Chapter III: Critical Issues for Oil Sands Development.** This chapter identifies and assesses critical areas of uncertainty or disagreement related to oil sands development. These issues include carbon emissions, water and land use, and the pace of technological advancement.

Report Objectives (continued)

- **Chapter IV: Scenarios to 2035.** The purpose and value of the scenario process is explained, and CERA's three oil sands scenarios to 2035 are presented. Each scenario is based on a unique set of assumptions regarding key factors that will shape oil sands development and stakeholder interests. There is no "right" scenario, but taken together the scenarios provide a framework for exploring the implications of various development paths.
- **Chapter V: Conclusion.** Given the range of stakeholder interests, there is not a singular path forward in the discussion about oil sands development. But a shared understanding of the issues, potential benefits, and challenges will help to move the debate forward in a constructive manner. This is the unifying goal of *Growth in the Canadian Oil Sands: Finding the New Balance.*

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

The world is searching for the right balance between increasing oil supply to meet aspirations for higher living standards and greater energy security, while at the same time protecting the environment, particularly in the face of concern about climate change. How this mix of interests evolves will be a defining feature of the early twenty-first century.

Development of the Canadian oil sands encapsulates the complexities the world faces on energy, environmental, and security issues. The oil sands are an immense resource—second only to Saudi Arabia in recoverable oil reserves. They are the sixth largest source of new supply additions in the world since 2000—ahead of Iran, Kuwait, and China. Further development offers Canada the potential to become one of the largest oil producers in the world and to continue to expand its position as the number one foreign supplier of oil to the United States. Furthermore, the oil sands are part of the dense network of economic, political, and energy relations between the United States and Canada. The oil sands themselves are a key element in the vital trade link between the countries: Canada is the largest trading partner of the United States. The two-way trade between the countries reached $597 billion in 2008, and Canada ranks by far as the largest market for American exports of goods and services.

The future of oil sands development is of great importance to Canada's overall economy. Major US interests are at stake, and there will be a significant global impact as well. The world's demand for energy will rise over the next several decades. CERA projects that total world energy demand in 2035 could as much as double from where it is today. Alternative forms of energy, such as biofuels, wind, and solar power, will play a growing role in satisfying higher demand, but so will fossil fuels, including oil. Indeed, all forms of energy—as well as greater efficiency—will be needed to deliver and support higher living standards around the world.

Will there be sufficient future investment in innovation, energy production, and efficiency to meet the energy needs of consumers around the world? If one or more of these factors falls short, energy could constrain economic growth instead of serving as an engine of development and rising living standards. There are no easy answers to the world's energy, environment, and security challenges.

Oil today accounts for 35 percent of global energy supply—the largest share of any form of energy. In 2035 oil will still play a central role in world energy supply. CERA's estimates of global oil demand in 2035 range from 97 million barrels per day (mbd) to 113 mbd. In 2008 world oil demand was 85.2 mbd.* Even in a world of relatively slow demand growth, new supplies of oil will be needed, especially to meet demand for greater mobility among those entering middle income levels around the world and to offset declining production in existing oil fields. The size and location of the oil sands resource means it has the potential to play an increasingly important role in satisfying oil demand—especially in North America.

*The 2008 figures include 1.2 mbd of global biofuels demand.

From the economic and energy security points of view there are compelling arguments in favor of strong expansion of the oil sands. Yet, at the same time, as with any form of energy, development has an impact on the environment. The production and processing of oil sands are among the more carbon-intensive when compared to other liquid fuels. Also, the cumulative impact of development on Alberta's water and land resources and on local and Aboriginal residents is not yet fully assessed.

The recognition of the significance of oil sands provides the motivation for this CERA study. The study has three objectives:

- first, to provide local, regional, and global contexts on the oil sands and explain why issues surrounding their development matter
- second, to identify and assess issues that will affect oil sands development—with a particular focus on those that generate debate or face uncertainty
- third, using our scenario framework, to illustrate how the future could unfold under three different sets of assumptions about oil sands development, economics, politics, and technology

THE KEY INSIGHTS

What factors will have a major impact on oil sands development? What issues are the focus of debate or face an uncertain future? A central element of this report is assessment of questions that will be critical for development but lack a shared understanding among stakeholders.

The issues surrounding future oil sands development do not necessarily lend themselves to clear-cut answers. The evolution of a number of critical issues, ranging from climate change regulation to Aboriginal rights, is uncertain. Views on the benefits and impacts of oil sands development span a wide spectrum.

CERA has identified key insights about the oil sands that illuminate issues that are uncertain or a focus of debate. These insights are informed by CERA's own research over the past eight months, combined with the results of a series of workshops in Calgary; Washington, DC; and Fort McMurray, Alberta, as well as the insights gained from the development of our three oil sands scenarios.

Energy Security and US-Canada Relations

The oil sands resource offers North America the possibility of further increasing continental oil supply security. Significant growth in oil sands imports into the United States will reduce the required volume of oil imports from elsewhere in the world. The oil sands are sourced from a politically stable and secure country adjacent to the United States. The United States is a natural market for Canadian oil, since the neighboring markets are connected by pipelines. Often unrecognized is Canada's position as the number one foreign supplier of oil to the United States. Canada's share of US oil imports rose from 15 percent in 1998 to 19 percent in 2008, underscoring the deep economic and trading relationship between the two neighbors as well as the critical role of energy in that bond (see Table ES-1). In our high growth scenario the oil sands would supply 37 percent of US oil imports by 2035—far more than any other foreign supplier. Greater Canadian oil exports to the United States result in fewer imports from elsewhere in the world than would otherwise be the case—shortening supply lines, among other advantages.

Canada and the United States have a long history of cooperation on energy issues, particularly on oil matters, although there have also been periods of significant contention. Cooperation is in the interests of both countries. A key challenge for continued cooperation is the development of a common framework for regulating greenhouse gas (GHG) emissions. A common Canadian-US framework for regulating GHG emissions would provide a more clear and solid climate for energy investments—including oil sands—compared with a world in which conflicting regulatory schemes emerge. An integrated approach would help to reduce market distortions and trade conflicts. The challenge of developing a shared set of policies should not be taken lightly, however. Developing a truly integrated approach between the United States and Canada for regulating GHG emissions would be a major milestone in international cooperation to combat climate change.

Greenhouse Gas Emissions

Comparisons of the GHG emissions of oil sands to other sources of crude oil are a source of great confusion. The confusion stems from using different boundaries to measure GHG emissions. The most comprehensive measurement of GHG emissions is on

Table ES-1

Top Five Sources of Crude Oil and Petroleum Product Imports to the United States, 1998 and 2008

(million barrels per day and share of total US imports)

1998

		Volume (mbd)	Share of Total US Imports (percent)
1	Venezuela	1.72	16
2	Canada	1.60	15
3	Saudi Arabia	1.49	14
4	Mexico	1.35	13
5	Nigeria	0.70	6

2008

		Volume (mbd)	Share of Total US Imports (percent)
1	Canada	2.46	19
2	Saudi Arabia	1.53	12
3	Mexico	1.30	10
4	Venezuela	1.19	9
5	Nigeria	0.99	8

Sources: US Energy Information Administration, Cambridge Energy Research Associates.

a life-cycle, *well-to-wheels* basis. The *well-to-wheels* basis includes GHG emissions from oil extraction, processing, distribution, through to the combustion of the refined products, such as gasoline and the resulting emissions that exit through the tailpipe. On this basis total GHG emissions from oil sands are approximately 5 to 15 percent higher than the average crude oil consumed in the United States. That is, about 5 to 15 percent more carbon dioxide (CO_2) in total is released into the atmosphere as a result of using oil sands instead of an “average” crude oil. Measuring GHG emissions in only part of the life cycle—the extraction, processing, and distribution part, or what is called *well-to–retail pump* or *well-to-pump*—can yield larger differences between oil sands and the average crude oil processed in the United States.

GHG emissions released during the combustion of refined products, such as gasoline, account for 70 to 80 percent of total life-cycle, well-to-wheels emissions. The well-to-retail pump portion of GHG emissions accounts for 20 to 30 percent of total life-cycle GHG emissions. GHG emissions from combustion of gasoline in an automobile will be the same regardless of the crude oil from which the gasoline is derived. Variability in GHG emissions from different sources of crude oil occurs mainly in the well-to–retail pump portion of the value chain.

Life-cycle GHG emissions from oil sands can be higher, lower, or on par with conventional crude oils since both oil sands and conventional crude have a wide range of emissions. This is why the very notion of comparing oil sands to an “average” barrel of crude oil is an additional source of confusion in considering GHG emissions. The United States consumes crude oils with a wide range of GHG emissions, some with emissions higher than those from the oil sands. The picture becomes even more complex since the carbon footprint of crude oil consumed in the United States is likely to change over time. First, over the life of a conventional oil field, the energy consumed to extract a barrel of oil can increase significantly because of the need for more energy-intensive extraction techniques. Second, the “average” conventional barrel imported into the United States may become heavier over time as high-quality light crude oil becomes scarcer. These issues highlight the critical importance of obtaining accurate and verifiable GHG life-cycle data from all sources of crude.

In the near to medium term reducing GHG emissions from oil sands production through efficiency improvements is likely to prove more cost effective and technologically feasible than carbon capture and storage (CCS) technology. In oil sands mining operations, improved process reliability can lower energy consumption per unit of oil sands processed, thereby reducing life-cycle GHG emissions. For in-situ operations, reducing the amount of steam required to produce each barrel of oil sands reaps rewards in decreased energy use and decreased life-cycle GHG emissions. This objective is consistent with advances in technology and efficiency achieved in recent years. The average amount of steam used today per unit of output is half what it was in 2000. The technology is expected to continue improving. In contrast, CCS is a longer-term option because widespread commercialization of CCS is expected to be years away, and CCS would substantially increase capital and operating costs. An additional challenge in implementing CCS for oil sands is the need to develop CO_2 pipelines to an appropriate storage area.

Local Environmental Issues

Water availability is unlikely to constrain oil sands development, but improvements in water management are necessary. Oil sands mining operations rely on the Athabasca River for water. The water issues rise and fall with the river itself, for the river is seasonal, with much lower flow in winter than in summer. Thus, water issues are more significant in the winter. For all scenarios, water storage will be needed to meet the needs of oil sands mines during the winter months, when withdrawal limits from the river are lower. Technological improvements in the management of mining waste will also allow more water recycling and reduce the amount of water needed from the Athabasca River.

Regulations that govern water use, waste management, and site reclamation in the Alberta oil sands will need to address the cumulative impact of the industry's growth, not just individual projects. At the project level, government regulation of oil sands activities is stronger than in many other oil-producing regions in the world. However, given the potential scale of future activity, the cumulative impact of development could become increasingly significant. Regulatory bodies are now working to manage and provide regional standards for air quality, land impact, and water quality and consumption, in addition to the existing project-level regulations. Such cumulative regulations will be important for public acceptance of further oil sands development, as land impacts and water consumption are some of the most visible environmental aspects of these projects.

Research and technology improvement are needed to treat oil sands mining waste and reclaim tailings ponds. The tailings ponds store water and waste material (the tailings) from the oil sands extraction process. They currently cover an area equal to Staten Island, New York. Water from the ponds is recycled back into the process. The ponds also contain a layer of *fluid fine tailings*, a mixture of water and fine clay and silt that is the consistency of pudding or yogurt. Water does not separate naturally from this material. Removing enough water to turn fluid fine tailings into a firm surface that can support equipment traffic is one pathway for land reclamation. Technology for removing water from fluid fine tailings is advancing, and trials of several technologies are under way. End-pit lakes (EPLs) are a second method for incorporating fluid fine tailings into the landscape during land reclamation. EPLs consist of mining waste capped with a layer of fresh water. These lakes are designed to become permanent features in the landscape. No EPLs have yet been constructed, and research is needed to determine whether these lakes can become active ecosystems that support plant and animal life.

Impact on Aboriginal and Local Communities

The exercise of First Nations community rights could affect the pace and scope of oil sands development.* People of First Nations heritage make up approximately 2.8 percent of Alberta's 3.6 million population, totaling approximately 100,000 people. By law, First Nations groups must be consulted by government and industry on all development within the oil sands area that affects their traditional way of life, but the nature and process of this

*First Nations groups are indigenous Canadians that live south of the territory occupied by the Inuit people, a culturally and linguistically separate group of indigenous Canadians. Métis are people of mixed indigenous and European heritage. These three groups together constitute Canada's Aboriginal population.

consultation is under debate. Lawsuits by some First Nations groups currently in the courts challenge the way they are consulted prior to oil sands projects. In addition some First Nations groups downstream from oil sands developments have particular concerns about the health effects that some assert may be caused by the leakage of industry waste. However, the oil sands also represent a growing economic opportunity for Aboriginal communities, with long-term job opportunities and potential equity partnership in some projects.

Infrastructure constraints and cost inflation of goods, services, and labor will affect the pace and cost of oil sands investment. The rapid growth over the past several years has increased strains on housing, infrastructure, and community services in the oil sands region and resulted in a high cost of living. If these pressures are not alleviated, the region will have difficulty attracting people needed for essential services. All of this ultimately could slow long-term growth in the oil sands industry. The sudden slowing of industry investment in the wake of the recent oil price slump could give the region a chance to catch up with the population growth that occurred over the past several years. The region's dependence on the cycles of one industry complicates planning and underscores the need for industry and government innovation to address these "boom and bust" issues.

Economics

Oil sands, like other complex oil projects around the world such as deepwater developments, face the challenge of high costs. The oil price collapse from $147 to the $40 to $60 range rendered many planned oil sands projects uneconomic. At the peak of oil industry capital cost inflation, in summer 2008, the threshold crude oil price for an oil sands project ranged from about $60 to $85 per barrel.* Since the oil price decline, more than 70 percent of proposed projects have been postponed. Although oil sands costs are roughly comparable to some other potential large new sources of supply, they are more expensive than many projects in the Middle East and other lower-cost producing regions. Oil industry costs have begun to ease, but unless major technological breakthroughs result in lower costs, the oil sands will remain among the higher cost oil supply options.

Natural Gas Demand

The oil sands are a major consumer of natural gas, today representing about 20 percent of Canadian demand. That could grow to 25 to 40 percent of Canadian demand by 2035. Even considering sizable new unconventional supply, Canadian domestic gas production is currently expected to peak around the middle of the next decade. Without the addition of new supply, such as from the Mackenzie Delta and Alaska, exports from Canada to the United States might decline in order to meet the needs of a rapidly expanding oil sands sector. However, improved efficiency can reduce oil sands demand for natural gas. Additionally, gasification of petroleum coke or asphaltenes, small nuclear facilities, and use of solvents are all technologies under development that could reduce natural gas demand, although they have yet to be demonstrated commercially in the oil sands.

*The crude oil prices are for West Texas Intermediate and assume a 10 percent rate of return. CERA's cost estimates are based on actual costs at the time and not future cost expectations. These cost estimates are based on a 20 percent per barrel light-heavy crude price differential, capital cost of $126,000 per flowing barrel for an integrated mine and upgrader, $30,000 per flowing barrel for steam-assisted gravity drainage (SAGD), and exchange rate parity.

The Innovation Challenge

The pace of technological innovation in the oil sands has been substantial, and further advances should be expected. However, cooperation between governments and the private sector is crucial for the advancement of certain technologies, which requires stepped-up government support of research and development (R&D). Since the inception of the first commercial oil sands facility in 1967, the industry has made major technological strides in optimizing resources, innovating new processes, reducing costs, increasing efficiency, and reducing its environmental impact. Advances in mining technology and the development of the SAGD technique for in-situ production have reduced costs and GHG emissions. Incremental improvements will continue; several new technologies in various stages of development have the potential to radically change oil sands production. All of these, however, must be proven effective and economically viable on a commercial scale. Many potential advances will require the kind of basic research and demonstration that individual companies do not have the resources or incentive to conduct. Government-private partnerships will be important in the advancement of technologies to address environmental and efficiency challenges. The environmental and efficiency challenges for oil sands are classic cases for consistent, long-term government R&D spending. The importance of oil sands establishes why stronger multiyear government support for R&D across a broad range of technologies, not just CCS, is vital.

CERA'S THREE OIL SANDS SCENARIOS

The complexity and uncertainty of the oil sands' future lends itself to application of CERA's scenario process. No one can accurately predict the future, but we can explore the key forces that will shape the future and assess the impact of different outcomes. Scenarios acknowledge uncertainty and illustrate how the future could evolve in different ways. They encourage people to think about the future in a flexible way by disengaging from their current point of view and interests—and the inevitable human tendency to simply extrapolate from what is happening today.

Growth in the Canadian Oil Sands: Finding the New Balance builds scenarios around issues specific to the Alberta oil sands. CERA's scenarios represent three different potential outcomes intended to explore the boundaries for oil sands development. They are by no means the only possible paths of development that could be envisioned. Indeed, it is possible that the future will ultimately contain elements of all three scenarios. CERA does not assign probability to any scenario, but encourages stakeholders, policymakers, and industry to use the scenarios to think as broadly as possible to understand the forces of change and how to adapt to them.

CERA's three oil sands scenarios are briefly summarized below. The full scenarios are in Chapter IV of this report.

New Social Order

New Social Order imagines a world in which governments attempt to remake their economies on a platform of clean energy. The global economic crisis that began in 2008 is followed by severe oil supply disruptions, leading to a multiyear spike in oil prices above $100 per barrel. An activist government role in the Canadian and US economies along with strong policies to limit GHG emissions encourages expansion of alternative forms of energy. Regulatory oversight of the oil sands tightens further, particularly to address the cumulative impacts on air and water quality and land use created by oil sands development.

Oil sands production capacity initially grows rapidly in response to the rush of investment that follows the extended oil price spike. However, by 2020 industry costs have risen sharply, petroleum demand in North America is in permanent decline, and oil prices are in retreat. Environmental regulations are also significantly tighter. The intersection of increasing costs and declining oil prices squeezes producers' margins and deters significant oil sands developments after 2020. Having reached 2.9 mbd by 2020—which represents more than a doubling from current levels—oil sands capacity essentially stagnates for the rest of the scenario period. In 2035 production is 3 mbd.

A key feature of the New Social Order scenario is the rapid development of technology. Technology not only enables the scale-up of alternatives to petroleum, such as next generation biofuels and electric vehicles, it also allows the oil sands industry to reduce its environmental footprint. As a result of improved efficiency and advanced technologies, the GHG intensity of oil sands production improves by over 30 percent between 2008 and 2035.

Barreling Ahead

The *Barreling Ahead* scenario illustrates conditions that allow Canada to become one of the biggest producers of petroleum in the world by 2035. The scenario explores the economic and energy security benefits, as well as the environmental impacts of such an expansion.

In this scenario the Canadian government plays a strong role in maximizing the development of Canada's vast energy resources, ranging from support for new infrastructure to stepped-up R&D funding (including establishment of the Research and Innovation Network). A "great recovery" follows the "great recession" of 2008 and 2009, leading to sustained strong oil demand growth and robust light, sweet crude oil prices. Strong oil prices and moderation of industry costs support continuous investment in both integrated and upstream-only oil sands projects. Ultimately oil sands production reaches 6.3 mbd in 2035. At this level of production Canada is by far the biggest source of oil for the US market, supplying 37 percent of US oil imports. Asia, with its rapid rise in oil consumption, becomes an important new market for oil sands products outside of North America.

Growing demand for natural gas and water, management of mining waste, and land reclamation are all challenges posed by the rapid rate of production growth in Barreling Ahead. Natural gas consumption by oil sands projects reaches 40 percent of total Canadian gas demand by 2035. Oil sands–related GHG emissions also rise sharply, ultimately representing about 20 percent of total Canadian GHG emissions.

Deep Freeze

In the *Deep Freeze* scenario the great recession of 2008 and 2009 is just the prelude to a "great stagnation," in which low rates of economic growth persist for years in both North America and the overall global economy. Globalization—the prevailing economic paradigm of the past several decades—loses ground to the forces of nationalism, insularity, and protectionism.

Oil demand growth is sluggish and oil prices are weak for most of the scenario. Without question the economic and oil price environment of Deep Freeze is the most challenging of the three scenarios for Canadian oil sands producers. The oil sands boom is followed by a great—and long—bust. Only new projects well into their construction phase proceed, leading to some continued growth in the early part of the scenario's first decade. By 2013 production has reached 1.8 mbd, 0.5 mbd higher than current levels, but the development process for new oil sands projects comes to a virtual halt.

Some moderate production growth occurs through the second decade of the scenario period, as oil demand growth gradually recovers, capital costs in the oil sands drop, and the pace of new environmental regulation slows. Owing to relatively favorable economics for incumbent oil sands producers, total industry capacity grows very gradually, through expansion of existing facilities. Ultimately oil sands capacity reaches 2.3 mbd by 2035, the weakest of the three scenarios.

CONCLUSION

The oil sands today have moved from the fringe of energy supply to the center. Their commercial development makes Canada the world's second largest holder of recoverable oil reserves and an increasingly important part of the fabric of hemispheric and global energy security.

But new challenges face the oil sands industry. The world's most severe economic downturn in decades has cast a chill on many investment plans. Also, like other energy sources, the oil sands will be affected by the future path of GHG regulation in Canada and the United States. Increasing effort will go into technological advances that help manage emissions in the production of oil sands. Locally, a growing focus on the cumulative environmental impacts could change future water and land use.

Recognizing the significance and impact of oil sands is very important, and approaching the questions about oil sands in a sound fashion is essential. To do otherwise is to risk wider disruption in US-Canadian relations and other negative consequences. This report combines

IHS CERA's research with the learning and insights from workshops involving a wide range of organizations and stakeholders. The objective is to contribute to finding that appropriate balance on oil sands development that meets economic and security needs and, at the same time, safeguards the environment.

CHAPTER I: THE OIL SANDS STORY

CHAPTER I: THE OIL SANDS STORY

GROWTH IN THE CANADIAN OIL SANDS: FINDING THE NEW BALANCE

> Since the deposits of tar sand in Alberta are practically inexhaustible, much is hoped in Western Canada from their exploitation.
>
> —*New York Times,* April 7, 1935

For more than a century the oil sands of Alberta, Canada, have fostered great expectations. When the geologist Robert Bell speculated in 1884 that the oil sands were part of an enormous oil reservoir, it sparked an enduring vision of prosperity and greater North American energy security. This fired the imagination of entrepreneurs such as "Bitumen Bill"—a failed fur trader turned oil sands enthusiast. His quest for oil was frustrated by technical challenges, but he successfully trumpeted the possibilities in government halls.* The potential of the oil sands motivated both the Alberta provincial and Canadian federal governments to find ways to separate the oil from the sand. A chemist, Dr. Karl Clark, cracked the code in 1920. But the large-scale exploitation of Canadian oil sands was still a long way off.

The technical and economic barriers separating early pioneering efforts from large-scale commercialization were formidable and stubborn. It was not until 1967 that Great Canadian Oil Sands Ltd. established the modern age of commercial oil sands production. Even then it took until 2000—and required many advances in engineering—for the oil sands industry to reach a production level of 600,000 barrels per day (bd), equivalent to the output of a medium-size oil company. But then over the next eight years production growth picked up rapidly and more than doubled. The rise in oil prices from 2002 to 2008, a stable operating environment, attractive fiscal terms, and the open investment climate in Canada—numerous foreign and domestic companies are active—spurred the rise in oil sands output. By 2009 oil sands production reached 1.3 million barrels per day (mbd), near the total amount of oil produced by Kazakhstan or Algeria. Putting this growth in comparative terms, if measured as an individual country, the Canadian oil sands would be number six in the world in supply expansion since 2000, ahead of Kuwait, China, and Iran (see Table I-1).

Although the pace of oil sands expansion has been rapid in recent years, the future rate of growth is uncertain because of the current severe global recession and ongoing concerns about the environmental impact of oil sands development. But clearly the eventual outcome will be a decisive factor in the balance between global energy demand and supply and for energy security.

Oil Sands in the Global Energy Context

The immensity of the oil sands is their signature feature. It was the source of inspiration for Bitumen Bill and the main driver behind more recent government and oil company efforts to increase investment and output. Current estimates place the amount of oil that can be economically recovered from Alberta's oil sands at 173 billion barrels.** This is more than

**The New York Times,* May 28, 1922.
**This figure does not include the potential for reserves in Alberta's eastern neighbor, Saskatchewan. The source of this data is IHS.

Table I-1

Top 15 Sources of World Oil Supply Growth, 2000–08

(million barrels per day)

		2000	2008	Volume change 2000 to 2008
1	Russia	6.52	9.79	3.27
2	Saudi Arabia	9.07	10.45	1.38
3	Angola	0.75	1.89	1.15
4	Brazil	1.45	2.27	0.82
5	Algeria	1.44	2.21	0.77
6	**Canadian oil sands**	**0.60**	**1.30**	**0.70**
7	Kazakhstan	0.72	1.41	0.69
8	Azerbaijan	0.29	0.90	0.61
9	Kuwait	1.88	2.48	0.60
10	United Arab Emirates	2.62	3.21	0.59
11	China	3.23	3.81	0.58
12	Qatar	0.86	1.41	0.55
13	Iran	3.76	4.29	0.53
14	Libya	1.47	1.87	0.40
15	Sudan	0.18	0.49	0.31

Sources: Cambridge Energy Research Associates, International Energy Agency.
Note: Total Canadian oil production was 2.72 mbd in 2000 and 3.41 in 2008.
The total net increase in Canadian production was 0.69 mbd.

ten times greater than US oil reserves and well above the 115 billion barrels that is currently estimated for Iraq. Only Saudi Arabia has a larger oil reserve base. Although the current severe global recession is slowing investment, the potential remains for the oil sands to make Canada one of the very few countries in the world that could substantially increase oil production for the next several decades.

What role will the oil sands play in the context of global energy supply and demand? The drive for higher living standards in China, India, the Middle East, Russia, and elsewhere will, in the long term, remain as strong as it was in Europe, Japan, and the United States in the post–World War II years. Higher living standards mean longer life expectancy, lower infant mortality—and higher world energy consumption. Demand for energy will rise globally over the next several decades—as it will in the United States and Canada. CERA projects that world energy demand in 2035 could be 60 to 100 percent higher than the 2008 level. Alternative forms of energy, such as biofuels, wind, and solar power, will play a role in satisfying higher demand, but so will fossil fuels, including oil. Indeed, all forms of energy—as well as greater efficiency—will be needed to deliver higher living standards around the world.

Oil today accounts for 35 percent of global energy supply—the largest of any form of energy. In 2035 oil will still play a key role in providing the world with energy. CERA's estimates of global oil demand in 2035 range from 97 to 113 mbd. In 2008 world oil demand was

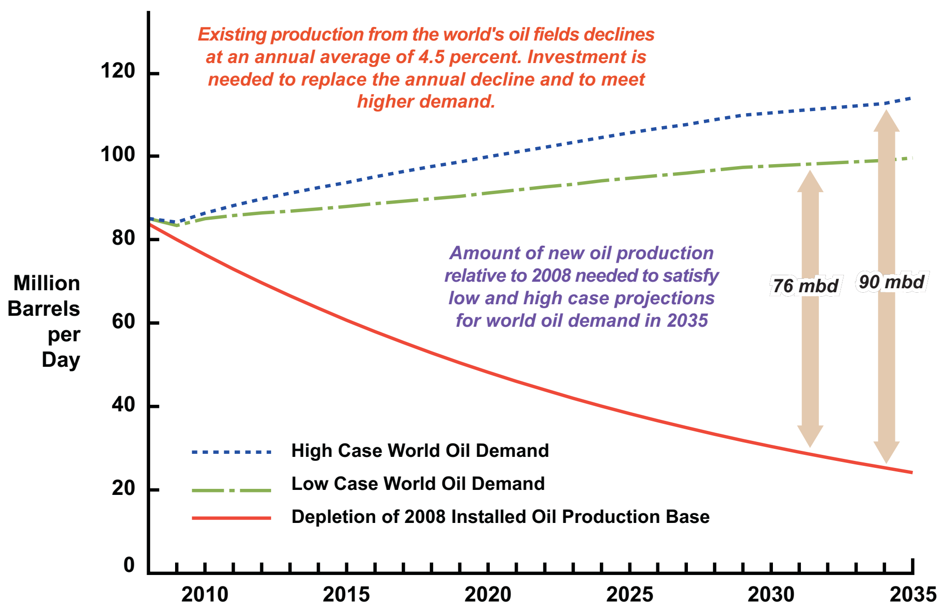
85.2 mbd.* Even in a world of relatively slow demand growth, more oil will be needed, especially to satisfy the demand for greater mobility among those entering middle income levels around the world.

The challenge to increase fuel supply is not simply about filling the gap between current and future demand. Oil is a depleting resource. Each year, the installed production base of the world's oil fields declines at an aggregate average of 4.5 percent.** This means, for example, that even if demand does not change from one year to the next, the global oil industry still needs to replace about 3.8 mbd of production to offset field depletion.*** By 2035 the world will need to find, develop, and produce 76 to 90 mbd of liquid fuel supply that was not in production in 2008 (see Figure I-1).

The size of the oil sands resource along with a production profile notable for a long and stable production plateau means that the oil sands could play an increasingly important role in satisfying the world's demand for energy. Indeed, the oil sands place Canada

Figure I-1

Filling the Gap:
Significant Investment Needed to Offset Oilfield Production Decline



Source: Cambridge Energy Research Associates.
90107-31

*The 2008 figures include 1.2 mbd of global biofuels demand.
**The aggregate annual decline figure includes fields that are increasing production, fields at production plateau, and fields in decline. It is based on the 2007 CERA Private Report *Finding the Critical Numbers: What Are the Real Decline Rates for Global Oil Production?*
***The 3.8 mbd of depletion is calculated based on 2008 global oil production (excluding processing gains) of 83.9 mbd. The amount of oil that needs to be replaced will change in line with future production levels.

among the "O-15"—CERA's list of the top 15 countries in terms of potential to increase oil production over the next decade (see Figure I-2). It is one of only two countries in the Western Hemisphere on the list, the other being Brazil.

So what role could the oil sands play in satisfying higher energy demand—and the desire for higher living standards? The range of oil production capacity in the oil sands in 2035, based on CERA's scenarios, ranges from 2.3 to 6.3 mbd. At the high end this would make it one of the very largest oil-producing regions in the world. Even at the lower end it would still be a significant source of world oil supply; few countries today produce more than 2 mbd.

If oil sands development faces a long-run standstill, then other resources would have to be developed elsewhere in the world or the possibility of higher energy prices would arise. To be sure, development of energy supply exacts costs, and the oil sands are no exception.

Big Resource, Big Challenges

A big resource often faces big challenges—and significant costs. Oil sands are not cheap to develop and produce. Indeed, high costs were the reason that it took the better part of a century for commercial production to commence. At the peak of the recent oil boom in

Figure I-2

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

Source: Cambridge Energy Research Associates.
90107-32

2008, the oil price needed to justify investment ranged from around $60 per barrel to $85 per barrel.* At the higher end of the range it placed the oil sands well above the cost of most other sources of oil supply. There are also environmental costs. With current technology the amount of carbon dioxide (CO_2) emitted during the production process places oil sands among the more carbon-intensive forms of liquid fuels. Water consumption and management as well as land use and reclamation are also of concern. We explore these issues in more detail in Chapters II and III.

Other significant challenges include managing the effects of development on the lives of Aboriginal people and on the natural landscape. The roles and responsibilities of government and oil sands investors regarding concerns of Aboriginal people lack clarity. This is an impediment to conflict resolution. Coping with dynamic infrastructure requirements linked to the booms and busts of the oil industry is a perennial challenge for local government. In the Municipality of Wood Buffalo—the de facto capital of the oil sands region—population growth has put great pressure on infrastructure and local services.

Debate is wide-ranging about the appropriate pace of development and environmental protection, but one aspect of the oil sands industry is clear: it has become an important engine of economic activity for Alberta and Canada. The United States also benefits from spending to develop oil sands. Specific economic benefits include

- More than C$150 billion was spent from 2000 to 2008 on oil sands development and related activities. About 80 percent of this was spent in Canada and 20 percent in the United States and other countries.
- Approximately 240,000 jobs are directly or indirectly related to the oil sands.
- More than C$30 billion in government revenues were collected from oil sands–related activities from 2000 to 2008. Revenues were paid to municipal, provincial, and federal governments.**

Oil Sands Development: A North American Issue

Few bilateral relationships match the history and density of links between Canada and the United States. The two countries enjoy a long history of cooperation based on deep economic and cultural connections. A very visible manifestation is the longest unmilitarized border in the world, across which roughly $1.5 billion worth of goods is traded every day. Canada is the largest trading partner of the United States. On security matters, in addition to both being members of the North Atlantic Treaty Organization, Canada and the United States have jointly run since 1958 the North American Aerospace Defense Command.

*The crude oil prices refer to West Texas Intermediate and assume a 10 percent rate of return. CERA's cost estimates are based on actual costs at the time and not future cost expectations. These cost estimates are based on a 20 percent per barrel light-heavy crude price differential, capital cost of $126,000 per flowing barrel for an integrated mine and upgrader, $30,000 per flowing barrel for steam-assisted gravity drainage (SAGD), and exchange rate parity. Projects announced in summer 2008 had higher capital costs than our estimates of actual costs at that time. Announced projects included expectations of future cost increases.
**CERA estimated the economic benefits based on the methodology outlined in the Canadian Energy Research Institute's 2005 report on the economic impacts of the Alberta oil sands industry.

Energy has long been a key pillar of the bilateral relationship, and the oil sands are an increasingly important part. Canada is, by far, the largest oil exporter to the American market. In 2008 Canada accounted for 19 percent of US oil imports, and an increasing proportion of this share consists of oil sands–derived liquids.* The number two supplier of oil to the United States, Saudi Arabia, accounted for 12 percent of imports. If the oil sands were a country, they would be the sixth largest exporter of crude oil to the United States, ahead of Algeria, Angola, and Iraq. Unlike other foreign sources of oil, Canadian oil is linked to the United States by pipeline and is not dependent on waterborne crude oil carriers. Canada is also the number one source of natural gas imports to the United States, accounting for 90 percent of total imports and 15 percent of total supply in 2008.

Oil is often an important part of the dialogue between the countries and their leaders. This is certainly the case today. On the eve of his trip to Canada, and maiden voyage abroad as president of the United States, President Barack Obama framed the oil sands challenge this way, "The dilemma that Canada faces, the United States faces, and China and the entire world faces is, how do we obtain the energy that we need to grow our economies in a way that is not rapidly accelerating climate change?"

The questions raised about future oil sands development are related to the many critical issues facing North America today. Will Canada and the United States develop a common framework on regulation of greenhouse gas (GHG) emissions—a factor that could have a large impact on investment? What is an appropriate balance between oil supply security and environmental protection, and how can these objectives be met at the same time? The outcome of these issues will reverberate in both Canada and the United States for years to come.

The Need for Common Understanding and Framework

The onset of a severe global recession in late 2008, which pushed oil prices down from a peak of $147 per barrel to around $40 to $50 in just a few short months, cast a chill on oil sands investment—as it did on other segments of the energy industry. Many projects have been postponed. Growth projections have been revised down. The size of the oil sands workforce has plummeted. By the end of 2010 the construction workforce is projected to be less than 30 percent of that of summer 2008 and well below the Alberta labor supply.

The timing of a global economic recovery is an immediate concern that will certainly affect the pace of investment and economic development. But other issues loom large and will endure after the worst of the "great recession" is behind us. These issues are in the realm of environmental regulation, technology, oil market trends, industry costs, and US-Canada relations. Many of these issues do not lend themselves to clear-cut sound bites or headlines. The complexity and dynamic nature of the factors that shape the oil sands industry make easy answers elusive. Future development and investment paths can produce benefits in one domain but costs in another. For example, a cost for emitting CO_2 would help to constrain such emissions and combat climate change but could also negatively affect energy security.

*US Energy Information Administration data for crude oil and product imports.

Identifying what is known and not known on key issues, particularly where there is great controversy, is critical to developing a shared frame of reference to advance dialogue among stakeholders in the oil sands industry. This CERA study aims to provide an objective, fact-based assessment of the issues that will shape the oil sands industry—particularly on matters where there is a wide range of perspectives—and provide local, regional, and global context for how the oil sands fit into the global energy picture. This assessment then provides the context for examining how the future could unfold using different assumptions in three scenarios to 2035. It is not our intention to identify the "right" way forward. Instead, the aim of this CERA study is to contribute to broader understanding of the risks, benefits, and impacts of oil sands development and to finding an appropriate balance between oil sands development and related economic, environmental, and social concerns.

The Oil Sands: What, Where, and How?

Grains of sand covered with water, bitumen, and clay—these are the oil sands. The "oil" in the oil sands comes from bitumen, an extra-heavy oil with high viscosity. Bitumen does not flow like a liquid at room temperature. Instead, raw bitumen is akin to an ice hockey puck. Given their black and sticky appearance, the oil sands are also referred to as "tar sands." Tar, however, is a man-made substance derived from petroleum or coal.

The bitumen content of the oil sands ranges from about 1 to 18 percent. The rest is mainly sand—principally quartz—and water. There are traces of other substances such as iron, mica, nickel, titanium, vanadium, and others. Oil sands producers separate the bitumen from the sand and water in order to derive the feedstock from which marketable oil is manufactured.

Where Are the Oil Sands?

Canada's oil sands are concentrated in three major deposits. The largest is the Athabasca, a large region around Fort McMurray in northeastern Alberta. The other two areas are Peace River in northwest Alberta and Cold Lake, east of Edmonton (see Figure I-3). There are also oil sands deposits in Saskatchewan, but their commercial viability has yet to be established. Outside of Canada, bitumen or extra-heavy oil deposits are found in many places around the world, but the only other large-scale development is in Venezuela.

How Are the Oil Sands Produced?

Conventional oil is a liquid that flows naturally or is induced to flow through enhanced recovery techniques from underground formations. Oil sands are unique in that they are produced via both surface mining and in-situ thermal processes.

- **Mining.** About 20 percent of currently recoverable oil sands reserves lies close enough to the surface that it can be mined. In a strip-mining process similar to coal mining, the overburden, primarily soils and vegetation, is removed, and the layer of oil sands is excavated using massive shovels that scoop the sand on to 400-ton trucks that transport it to a processing facility (see Figure I-4). The first two large-scale oil sands plants, which commenced in 1967 and 1978, are such mining operations. In 2008 over 55 percent of oil sands output was mined. The minable portion of the oil sands is located north of Fort McMurray and is orange-shaded on Figure I-3. The current footprint of mining operations is about 200 square miles (518 square kilometers), or about 2 percent of the total area of the greater Houston, Texas, metropolitan area.* It generally takes about two metric tons of mined oil sands material to produce 0.13 tons (approximately one barrel) of synthetic crude oil (SCO).

The Oil Sands: What, Where, and How? (continued)

- **In-situ thermal processes.** About 80 percent of the recoverable oil sands deposits are too deep to be mined and are recovered using in-situ thermal processes. Two thermal processes are in use today: steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). Both methods inject steam to lower the viscosity of the bitumen and allow it to flow to the surface. CSS is primarily used in the Cold Lake and Peace River areas, whereas SAGD predominates in the Athabasca region. Production from CSS and SAGD were roughly equivalent in 2007 at about 200,000 bd each. In 2008 SAGD production exceeded CCS. SAGD is expected to account for a large share of the total growth in oil sands output. Figure I-5 illustrates the SAGD process. The steam-oil ratio (SOR) is a critical variable for thermal production. It measures how much steam—generally made via natural gas—is needed to produce a barrel of bitumen. For example, an SOR of 3 means that three barrels of water at atmospheric pressure and temperature must be vaporized into high-pressure steam to produce one barrel of bitumen. Much of the of the water used to make steam comes from the production of the bitumen and is recycled.

What Is the Final Product?

Raw bitumen cannot be transported in pipelines or processed in conventional refineries. It must first be diluted with a light oil liquid or converted into a synthetic light crude oil. Several crude oil–like products are produced from bitumen, and their properties differ in some respects from conventional light crude oil (see Figure I-6).

- **SCO** is produced from bitumen via refinery conversion units that turn very heavy hydrocarbons into lighter, more valuable fractions from which gasoline and diesel are manufactured. These units are called upgraders. SCO resembles light, sweet crude oil, with an API gravity typically greater than 35 degrees. However, since SCO produces a more limited range of products compared with conventional crude oil, a typical refinery can use SCO as only a small fraction of its total feedstock.**
- **Diluted bitumen (dilbit)** is bitumen mixed with a diluent. The diluent is typically a natural gas liquid such as condensate. Dilbit is generally a mix of 70 percent bitumen and 30 percent condensate. This is done to make the mixed product "lighter," and the lower viscosity enables the dilbit to be shipped in a pipeline. A typical refinery will need modifications to process large amounts of dilbit feedstock because it produces more heavy oil products than most crude oils. Dilbit is also lower quality than most crude oils. It contains high levels of salt, sulfur, nitrogen, metals, and aromatics. Dilbit also has a high amount of corrosive acid, as measured by the total acid number (TAN). The high acid limits the number of refineries that can process dilbit. Refineries already configured to process very heavy oil are the exception. For other refineries, upgraded metallurgy is often required to process dilbit. Not all bitumen has the same acid level—and oil sands from the Cold Lake region tend to have the lowest acid levels.
- **Synbit** is typically a combination of 50 percent bitumen and 50 percent SCO. The properties of each kind of synbit blend vary significantly, but the blending of the lighter SCO with the heavy bitumen results in a product that more closely resembles conventional crude oil.

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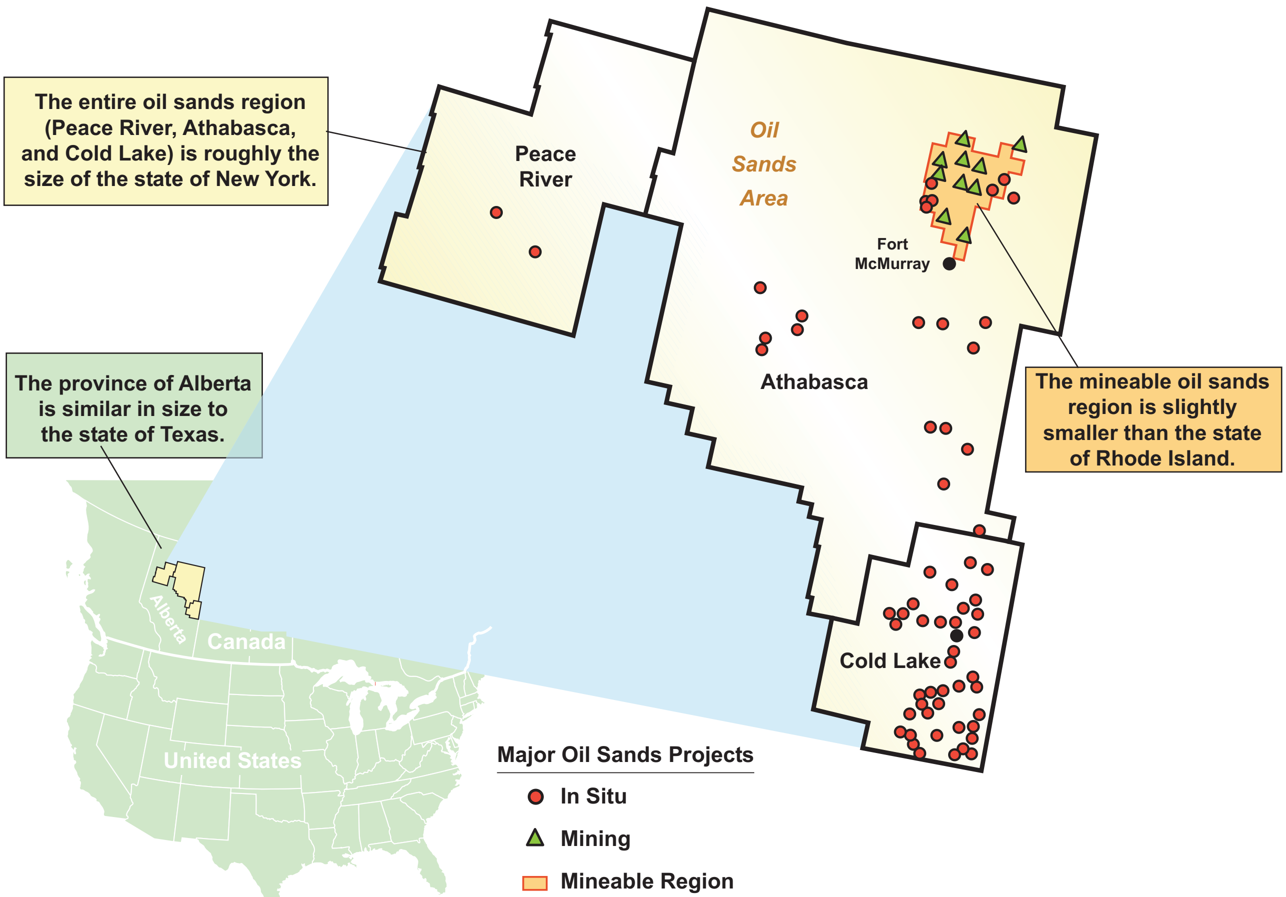
*Disturbed land is 200 square miles due to surface mining. The total amount of land leased for surface mining is 1,350 square miles, which is equivalent to 0.5 percent of Alberta's total land.
**Since SCO does not contain residual (heavy) oil, processing too much SCO will lead to imbalances in the refining process that will reduce the refinery's throughput.

Figure I-3

Location of Canadian Oil Sands Resources



Source: Cambridge Energy Research Associates,
Note: Comparisons to US states are to the total areas of the states, including land and water.
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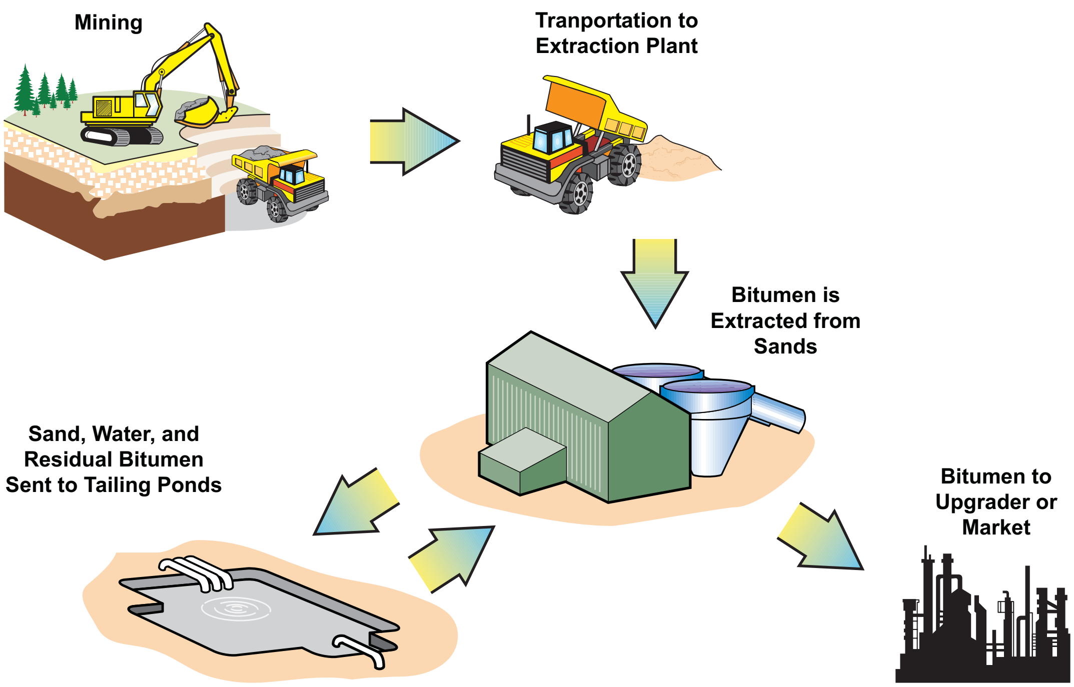
Figure I-4

Oil Sands Mining Process



Source: Cambridge Energy Research Associates.
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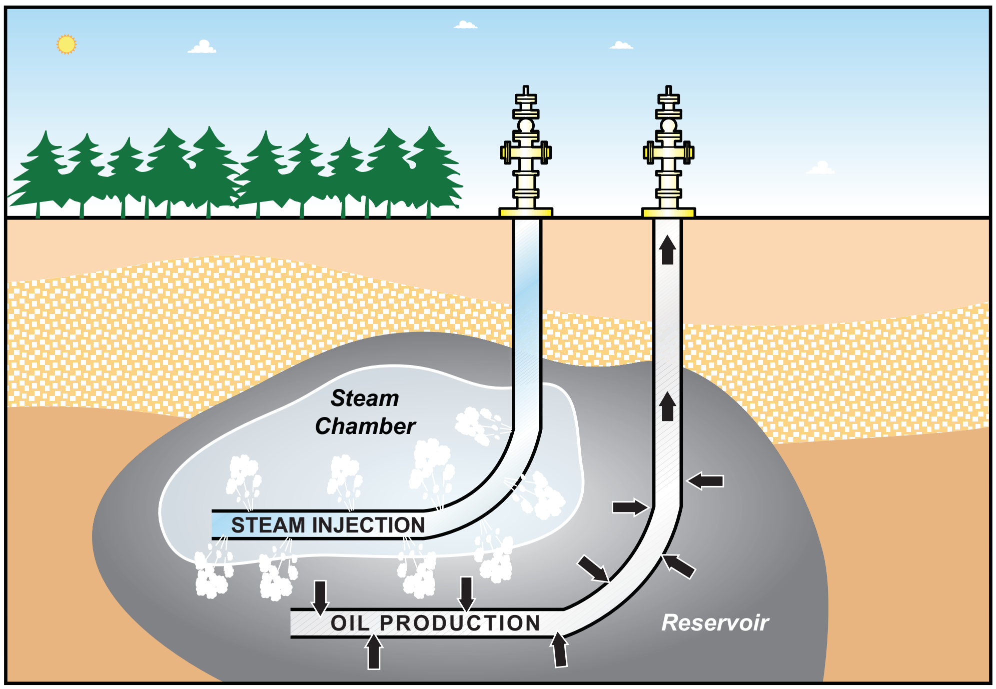
Figure I-5

The Steam-assisted Gravity Drainage (SAGD) Production Technique



Source: Cambridge Energy Research Associates.
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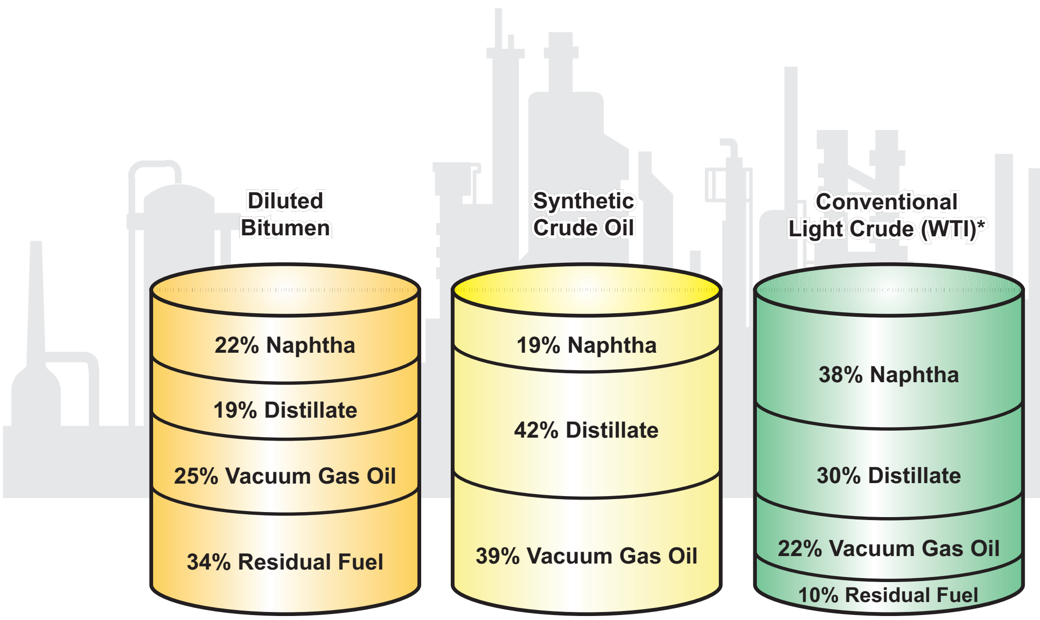
Figure I-6

Products Derived from Oil Sands Compared to Conventional Light Crude



Source: Cambridge Energy Research Associates.
Note: Percentages are approximate and can differ based on specific liquid qualities and the refinery in which it is processed. Gasoline is derived from naphtha material. Distillate material produces diesel fuel, heating oil, and jet fuel. Vacuum gas oil is a heavier material that can be upgraded to yield both gasoline and distillate. Residual fuel is a very heavy, low value material typically used as boiler fuel. It can also be upgraded to lighter products, although this requires deep conversion refinery units.
*WTI is West Texas Intermediate (WTI), which is a conventional light crude oil. WTI is the price benchmark for oil sold in the United States.
90107-11

CHAPTER II: THE POLITICAL AND SOCIAL CONTEXT OF OIL SANDS DEVELOPMENT

CHAPTER II: THE POLITICAL AND SOCIAL CONTEXT OF OIL SANDS DEVELOPMENT

Policy at every level of government influences oil sands development. The nature of the relationship between Canada and the United States will influence future policy to regulate greenhouse gas (GHG) emissions and affect the downstream market competitiveness of products produced from oil sands. The Canadian federal and Alberta provincial governments' stance on oil sands is also critical and changing. Alberta recently released a long-term development plan for the oil sands, focusing more on sustainability than in the past. First Nations groups have treaty rights throughout the oil sands area, and some First Nations are challenging oil sands developments. The rapid growth of the oil sands industry has challenged the infrastructure and social services in the Regional Municipality of Wood Buffalo, the center of Alberta's oil sands development.

OIL SANDS: THE LATEST CHAPTER IN US-CANADA ENERGY RELATIONS

Key question: Will Canada and the United States work cooperatively to develop common and complementary policies on energy issues and on GHG emissions—or will national perspectives dominate?

Why it matters: Past cooperation between Canada and the United States on energy issues has been mutually beneficial. In contrast, during times when common ground was not reached, trade and investment in oil was negatively affected. The degree of future US-Canada cooperation will influence policy on GHG emissions, which will shape oil sands development and downstream market access.

Continental or National Perspective?

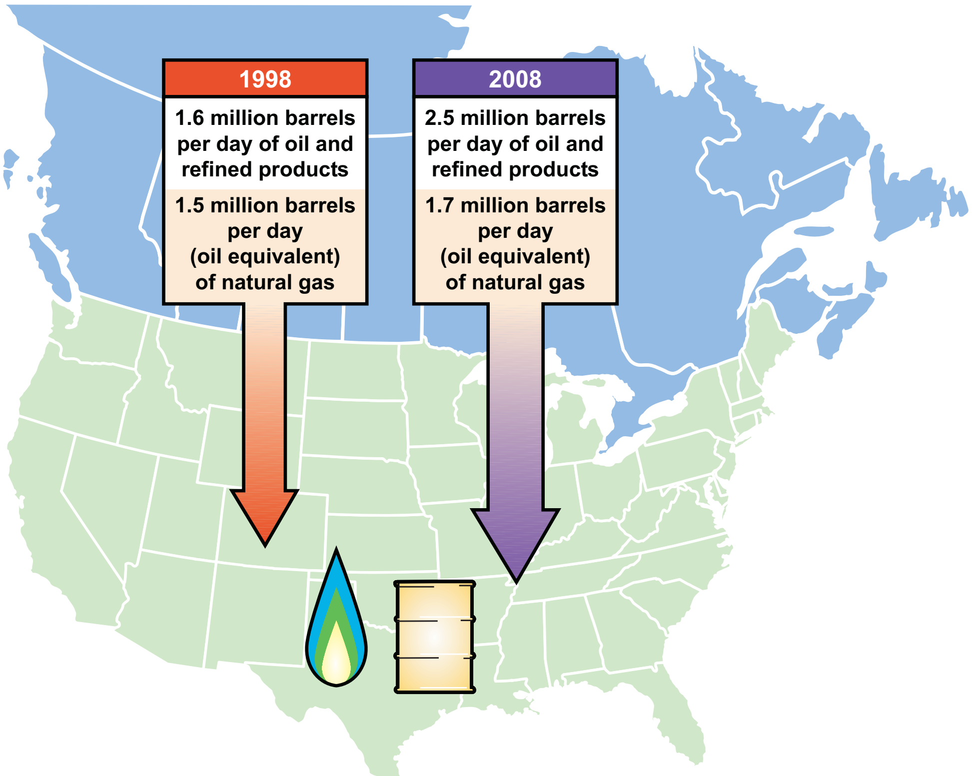
Physical connections between Canada and the United States create a strong bond—8,891 kilometers (5,521 miles) of shared border and $596.9 billion in annual trade flows.* Oil and gas provide another strong connection. The United States is virtually Canada's sole oil and gas export market at present. In 2008 Canadian oil and gas exports totaled 4.2 million barrels per day of oil equivalent (mbdoe)—more than double the number two US supplier (see Figure II-1).**

The oil and gas connection reflects a shared vision of the benefits of an integrated continental oil and gas market. But there have been times when a shared vision was elusive—and trade and investment suffered. Will the future be marked by cooperation based on a shared vision or by disengagement?

*In 2008 the United States exported $261.4 billion of goods to Canada and imported $335.5 billion.
**According to the US Department of Energy in 2008 Canadian crude oil (including oil sands) and refined product exports totaled 2.5 mbdoe and Canadian natural gas exports totaled 1.7 mbdoe. According to the National Energy Board of Canada, 0.7 mbdoe of synthetic crude and blended bitumen from the oil sands were exported to the United States in 2008.

Figure II-1

Canadian Crude Oil, Refined Products, and Natural Gas Exports to the United States, 1998 and 2008



Source: Cambridge Energy Research Associates.
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Bilateral relations between Ottawa and Washington are crucial. Trends in the world oil market and geopolitics will also shape the path toward or away from cooperation. A look back at history sheds light on the important role of cooperation—or lack thereof—in shaping the outcome of key periods of Canadian-American energy relations.

- **Cooperation—1940s to 1973**
  - During World War II, when the United States was the main supplier of oil to Canada, cooperation led to the border's being "ignored in order that necessary programs might be carried forward with a minimum of dislocation and inefficiency."*

*Paul Chastko, *Developing Alberta's Oil Sands*, quoting from *A History of the Petroleum Administration for War: 1941–45,* Washington, Government Printing Office.

- In the late 1940s the Canadian oil industry blossomed because of investment by American oil companies. Canada then became an exporter of oil to the United States.

- In the late 1950s further growth in Canadian oil production was under threat due to US import restrictions. In 1959 the administration of US President Dwight Eisenhower exempted Canada from an import quota, despite a large surplus of US oil production capacity, to enhance what was explicitly seen as North American energy security.

- In 1969, as oil production grew in the western provinces, the Canadian government sought assurance of greater access to the US market.

• **Strained relations—1973 to 1989**

- The 1973 oil embargo ushered in a tumultuous period for US-Canada oil relations and a more nationalistic era. Canada raised the price of oil for US buyers—in line with OPEC prices—but subsidized domestic prices. Taxes on oil companies increased, and pressure grew for greater Canadian ownership of domestic oil companies. These developments constrained investment. The net effect was a decline in Canadian oil production from 2.1 million barrels per day (mbd) in 1973 to 1.6 mbd in 1976—a 24 percent drop in three years.

- In 1975 Canada became a net oil importer. Tense oil relations complicated discussions aimed at building a pipeline to ship Alaskan and northern Canadian gas to the United States. This pipeline still has not been built.

- In 1980 the government of Prime Minister Pierre Trudeau introduced a National Energy Program that created incentives for increasing Canadian ownership of the still largely American-owned petroleum industry. This change added to ongoing weakness in oil production, and Canada remained a net oil importer until 1983.

• **Renewed cooperation—1989 to present**

- In 1989 a free trade agreement between the United States and Canada marked a return to cooperation and integration of energy markets by enshrining the “fullest possible” trade in energy. The pact forbids the Canadian government from imposing higher prices for exported oil and gas relative to the domestic market price.

- The US-Canada free trade agreement laid the groundwork for the 1993 North American Free Trade Agreement (NAFTA), which reaffirmed the oil and gas trading framework between Canada and the United States. Investment and trade flows of oil and gas have grown since the agreements were adopted. For example, Canadian crude oil exports to the United States doubled from 1993 to 2008.

New Challenges to the US-Canada Energy Relationship

Will Canada and the United States continue to cooperate on energy issues, including environmental matters? Early signs point toward a partnership in developing a common framework for reducing GHG emissions—an issue of critical importance to oil sands investment. In February 2009 the US-Canada Clean Energy Dialogue was established, a high-level forum to pursue cooperation on clean energy and environmental matters. Reducing the GHG emissions from fossil fuels will be an important issue. US President Barack Obama, just before his maiden trip to Canada, said, "I think it is possible for us to create a set of clean energy mechanisms that allow us to use things not just like oil sands, but also coal."

A common framework for regulating GHG emissions would provide a more clear and solid investment climate for oil sands investors than a world with conflicting regulatory schemes. An integrated approach would help to reduce market distortions and trade conflicts. However, the challenge of developing a shared set of policies should not be taken lightly. The United States and Canada have a history of cooperation on addressing emissions from conventional pollutants, such as sulfur dioxide and nitrogen oxides. Developing a truly integrated approach between the United States and Canada for regulating GHG emissions would be a major milestone for international cooperation to combat climate change. The low-carbon fuel standards currently under discussion at both the federal and state levels in the United States could be part of a cooperative climate change scheme if Canada adopted similar regulations or could be an impediment to cooperation if they are only adopted on the American side.*

The United States and Canada achieve some measure of cooperation on regulating GHG emissions in all three CERA scenarios: New Social Order, Barreling Ahead, and Deep Freeze. However, the agreement is early and wide-ranging in New Social Order and late and limited in Deep Freeze. Barreling Ahead lies between these two extremes with respect to Canadian-American cooperation on GHG emissions.

FEDERAL AND PROVINCIAL GOVERNMENTS' CHANGING FOCUS

Key question: How will federal and provincial regulation of oil sands evolve over time?

Why it matters: Oil sands developments in Alberta are subject to a complex web of regulation. The regulatory environment can slow or accelerate the pace of development of oil sands projects, and it largely determines the degree of environmental protection included.

*A federal law in the United States may affect a small portion of the US market for oil sands products, but its interpretation is uncertain. Section 526 of the Energy Security and Independence Act of 2007 prevents the US government from buying fuel produced from "nonconventional petroleum sources" with life-cycle GHG emissions greater than fuel produced from "conventional petroleum sources." The definitions of "nonconventional" and "conventional" are unclear, and thus it is not clear whether the provision applies to products produced from Canadian oil sands.

Federal and Provincial Regulatory Agencies

Regulatory oversight of oil sands involves a number of entities, including several provincial agencies, due to the complex issues involved. The Alberta Ministry of Energy is responsible for energy policy and strategy, while the Energy Resources Conservation Board (ERCB) is responsible for regulation. The Ministry of the Environment is responsible for safeguarding and enhancing Alberta's environment and for developing Alberta's Climate Change Strategy. Alberta's legislature passed a law that requires facilities that emit more than 100,000 metric tons of carbon dioxide (CO_2) per year to reduce their emissions intensity by 12 percent below their 2003 baseline. Although Alberta was one of the first regions to establish emissions limits in North America, its policy is far less stringent than those being discussed at the federal level in both Canada and the United States. The provincial Ministry of Sustainable Resource Development is charged with managing the province's public lands, forests, fish, and wildlife.

The federal government also plays an important role in oil sands regulation. Environment Canada, the federal ministry, has jurisdiction in many areas affecting water and air quality, particularly where these issues cross provincial borders. Through its Canadian Environmental Assessment Agency it works with the ERCB as part of a joint review process for oil sands projects to address their long-term environmental impacts. Environment Canada is also responsible for developing a climate change strategy at the federal level. The Department of Fisheries and Oceans has some jurisdiction over water quality and use. Finally, Natural Resources Canada and its regulatory arm, the National Energy Board, regulates construction, expansion, and tariffs on interprovincial and international pipelines that carry oil, natural gas liquids, and natural gas. It is also responsible for authorizing short-term orders for all oil exports and both short- and long-term orders for natural gas.

Shift in Regulatory Focus

Through the 1990s federal and provincial regulation of oil sands aimed to foster growth to maximize economic benefits for Alberta and Canada as a whole. In 1995 the National Oil Sands Task Force, a group including representatives from government, oil companies, unions, and municipalities, focused on how to increase investment in the oil sands, with a goal of producing 1.2 mbd by 2020. The Alberta government reduced royalties to as little as 1 percent, and the federal government provided strong income tax incentives. At first little investment resulted, but increasing oil prices and improvements in oil sands technology brought explosive growth after 2000. Oil sands production reached the goal of 1.2 mbd in 2007, a full 13 years ahead of the task force's goal.

Oil sands developments have always gone through a comprehensive project-specific evaluation of their economic, environmental, and social impacts. This project-by-project model of regulation served the industry and public well when there were fewer developments. However, the scale of development and the number of projects have increased dramatically since 2000, raising questions about the cumulative impact of all oil sands development. The Cumulative Environmental Management Association, created in 2000, was the first multistakeholder group to attempt reconciliation of the overall impact of multiple projects on the region's environment. The group's work continues, but several environmental nongovernmental organizations and First Nations have resigned from the group over what they saw as a lack of progress in managing the oil sands' cumulative impact.*

The Alberta Treasury Board created the Oil Sands Sustainable Development Secretariat in 2007 to specifically address rapid growth in oil sands development. It collaborates with other ministries, industry, communities, and various stakeholders to address social, infrastructure, environment, and economic impacts of oil sands developments. The Secretariat set forth its long-term sustainability agenda in *Responsible Actions: A Plan for Alberta's Oil Sands*, released on February 12, 2009. The plan's key objectives are to reduce the environmental footprint of oil sands, optimize economic growth, and increase quality of life for Albertans today and in the future. The plan also seeks to leverage the bitumen royalty regime to encourage construction of upgraders in Alberta and to focus oil sands research on more sustainable practices.

The Alberta government has also responded to concern about oil sands' cumulative impacts over the past year with new regulations and initiatives in the areas of land use, air emissions, tailings management, and water use. The Ministry of Energy recently issued a new energy strategy for the province. The Ministry of Sustainable Resource Development's new Land Use Framework is a step forward in thinking about sustainable development in the oil sands. The Framework includes an outcome-based approach to land development, the consideration of cumulative effects management in development decisions, and an effort to resolve potential conflicts between alternate uses of land. The ERCB has also issued several new and proposed regulations governing water use and mining waste management. All represent a shift toward requiring more sustainable growth.

Alberta also changed its oil sands royalty rates at the beginning of 2009. Royalties are now determined on a sliding scale based on West Texas Intermediate (WTI) prices. When WTI prices are between $55 and $120 per barrel, royalty payments range from 1 to 9 percent for operators that have not yet recovered their capital costs and 25 to 40 percent for operators that have recovered their capital costs. At today's oil prices of less than $55 per barrel, royalty payments have remained the same as before the policy change. Additionally, the Alberta government is moving forward with a plan to accept bitumen-in-kind for royalty payments. This bitumen will be sold to upgraders in Alberta to assure that value-added upgrading occurs within the province.

What Will the Future Bring?

Sustainability is likely to remain a key theme of future oil sands regulation. Pressure to introduce more regulations is not likely to fade, even with the decline in oil prices since 2008. Regulations focused on sustainable development are particularly prevalent in the New Social Order scenario. The low growth path envisioned in the Deep Freeze scenario makes further regulation less necessary.

*The members of the Cumulative Environmental Management Association that resigned were the Pembina Institute, the Toxics Watch Society of Alberta, the Fort McMurray Environmental Society, the Athabasca Chipewyan First Nation, and the Mikisew Cree First Nation.

Much of the oil sands area has already been leased to operators, but the province has an opportunity to take back leased land when the leases expire. This possibility is more likely under the strict regulatory environment of the New Social Order scenario. Typical oil sands leases are 15 years, although some older leases are as long as 21 years. If the land is not explored for oil production potential or developed during the lease term, the lease expires, and the land is returned to the Alberta government. Although some developers have negotiated an extension of the lease, the expiry date represents an opportunity for the government to take back some of the leased lands. Leases expire in the next five years for 18 percent of the total leased land area and in the next ten years for 33 percent of the leased land area.

Additionally, more data collection is needed to properly assess some environmental impacts, including site reclamation for mining projects, water use and pollution, and the cumulative impacts of the industry as a whole. Continuing focus by the regulatory authorities and industry on the cumulative impacts of oil sands development could lead to reduced environmental and social impacts and improved public perception of the industry.

FIRST NATIONS GROUPS AND TREATY RIGHTS

Key question: How will the exercise of First Nations rights in the oil sands evolve over time?

Why it matters: First Nations groups must be consulted on all development within the oil sands area. The nature of this consultation is under debate, and several lawsuits are under way to challenge how First Nations groups are consulted prior to oil sands development.

In 1899 the British government signed Treaty 8 with First Nation groups.* The treaty requires the Canadian government to consult First Nations on any activities that have the potential to affect their traditional way of life, including rights to hunt and fish, in an area of about 842,000 square kilometers (325,000 square miles). This area includes northern Alberta and parts of British Columbia and Saskatchewan, and extends into the Northwest Territories as far north as Great Slave Lake. The treaty includes about 8 percent of Canada's total land area and covers the entire region of the Athabasca oil sands. Approximately 100,000 people of First Nations heritage reside in Alberta.

Under the treaty First Nation rights to traditional land use can be infringed upon given other activities on treaty land, but the government must consult with the First Nations prior to making a decision to proceed with the disruptive activity. In 1930 the natural resources in Alberta were transferred from the federal government to the provincial government, and the obligation to consult with First Nations groups under Treaty 8 transferred to the province as well.

*First Nations groups are indigenous residents of Canada that live south of the territory occupied by the Inuit people, a culturally and linguistically separate group of indigenous Canadians. The Métis are people of mixed indigenous and European heritage. These three groups together constitute Canada's Aboriginal population.

The Alberta government does not engage in a consultation process for individual projects on treaty land. In the case of oil sands developments, the developing companies are required to consult First Nation groups directly and discuss, as well as mitigate to the extent possible, the impacts on First Nations' rights and traditional land uses. Both companies and First Nation groups are working to better understand and define "consultation." Many people on both sides believe that the Alberta government should play a more active role in the consultation process, helping to standardize the process and make the obligations on both sides more clear.

Several projects in treaty areas have been delayed or canceled due to a lack of proper consultation with First Nations groups. These include an injunction against the development of a billion-dollar hydropower development project in Quebec and the delay of the Mackenzie Valley pipeline. Delays are not limited to large, high-profile projects. In the oil sands region the Mikisew Cree First Nation in Fort Chipewyan won a legal action regarding a winter road through Wood Buffalo National Park that was approved without consultation.

The definition of consultation in the oil sands region is evolving, with three ongoing lawsuits challenging the way First Nations groups are consulted prior to oil sands projects. Two of these lawsuits challenge the Government of Alberta's right to grant oil sands leases to oil companies without consulting First Nations. Currently First Nations groups are consulted only after the land is leased to oil companies and the specific project planned for the area is defined. The third lawsuit challenges the consultation process on a specific project.

The outcome of these lawsuits and other engagement between the oil sands industry and First Nations groups has the potential to change the scope and pace of oil sands development. Cooperative engagement that meets the needs of industry and First Nations groups will be necessary to achieve the rates of growth envisioned in the Barreling Ahead scenario and the early years of the New Social Order scenario. This cooperation could occur through the intervention of the Alberta government, or perhaps through the formation of a negotiating body composed of oil sands producers. The low level of oil sands development envisioned in the Deep Freeze scenario lessens the impact of development on First Nations groups.

LOCAL COMMUNITY STRUGGLES TO KEEP UP WITH OIL SANDS DEVELOPMENT

Key question: How can the local community around the oil sands cope with the boom-and-bust cycle of development?

Why it matters: The remote nature of the oil sands region makes attracting and retaining workers difficult. The recent boom in oil sands activity has added to the challenge of providing community services to a rapidly growing population.

The rapid development cycle of oil sands development is difficult for local government to manage. The boom over the past several years caused many problems in the Regional Municipality of Wood Buffalo, where the majority of oil sands projects are located, and in Fort McMurray, the urban center of the oil sands region. Slowing investment in oil sands today could give the region a chance to catch up with the population growth of the past several years, or it could result in infrastructure construction for the next boom that never arrives. The region's dependence on one volatile industry makes planning a guessing game.

From the mid-1980s to the late 1990s little economic growth occurred in the region because of low oil prices, and population was nearly static. However, from 2000 to the present the population of Fort McMurray grew from approximately 42,000 to almost 70,000 as activity in the oil sands exploded along with oil prices. This population figure does not include the "shadow population" of temporary workers in camps and those who reside and work in the area part time, estimated at 25,000 at its height during summer 2008.

This rapid growth brought challenges for every type of infrastructure and community service in the area. Fort McMurray has become a boomtown, with all the escalating costs and quality-of-life issues that boomtowns face. Housing is in short supply, and Fort McMurray has been among the most expensive rental and real estate markets in Canada. The high cost of living means that the region has difficulty attracting and retaining workers for occupations apart from oil sands, including health care workers, teachers, and municipal employees. The health region that encompasses the Regional Municipality of Wood Buffalo has the lowest ratio of doctors to population in rural Alberta. Teacher turnover in the Fort McMurray public school system is 29 percent per year, compared with 4.5 percent in Edmonton.

Infrastructure is inadequate for the growing population. The water treatment plant and wastewater treatment plant need expansion immediately, and the solid waste landfill is nearly full. Highway 63 connects the oil sands region to Edmonton, 435 kilometers (270 miles) to the south. The road has only two lanes for most of its length and is notorious for traffic backups and deadly accidents, with 22 fatalities in 2007 and 6 people killed in a single day in three separate accidents in January 2009. Expansion of the road to four lanes is under way and complete for short sections, but a completion date for the entire highway is unknown.

Remedying these infrastructure shortfalls is particularly expensive in the Fort McMurray area, where construction costs have recently been two to three times the provincial average because the region is remote and because municipal projects compete with oil sands projects for labor and equipment. The high costs and sheer volume of work needed caused Alberta to modify the debt ceiling for the Regional Municipality of Wood Buffalo in 2006 to allow it to borrow more money than any other municipality in the province. Still the question remains, If low oil prices continue to reduce investment in oil sands, will these infrastructure investments be needed? Unemployment in Fort McMurray, unheard of as recently as summer 2008, is creeping upward as oil sands projects are delayed.

The fate of communities in oil sands area differs greatly across the three CERA scenarios. In Barreling Ahead so many workers come to the area that the province helps establish satellite communities outside Fort McMurray to house workers closer to their jobs and help minimize work camps. Additionally a portion of the large royalty revenues generated by Alberta is diverted back to the oil sands area to improve infrastructure and community services. Community growth is more manageable in the New Social Order scenario. Fort McMurray would likely shrink in the Deep Freeze scenario, as the lack of new project starts reduces the need for labor.

CHAPTER III: CRITICAL ISSUES FOR OIL SANDS DEVELOPMENT

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Development of the oil sands poses a number of challenges and questions. This chapter identifies critical areas of uncertainty or disagreement that are central to the future development of the oil sands industry in Alberta. Our goal is to illustrate these complex issues clearly to identify what is known and what is unknown, and to provide a common understanding and platform for discussing the contentious issues that affect oil sands development. The facts are in dispute for some of these issues; for others the questions are about future costs or technological advancement. Each of these issues has the potential to change the course of oil sands development.

ENVIRONMENTAL ISSUES

The environmental issues surrounding oil sands development are among the most visible and controversial. There are growing concerns in Canada, the United States, and around the world about the impact of oil sands development on the environment. However, rigorous and transparent comparisons of the environmental impact of oil sands with those of other sources of energy are in short supply. Greenhouse gas (GHG) emissions are a contentious issue, and estimates of the emissions difference between oil sands and more conventional fuels vary widely. Water management is also crucial. The oil sands mines take nearly all of their water from the Athabasca River, an ecologically important water body; in-situ production relies mostly on fresh and brackish groundwater, and the hydrogeology in the entire region is not well understood. Oil sands production, particularly mining, affects many square miles of land and produces considerable quantities of waste material. Many stakeholders, especially local residents, are concerned about companies' ability to manage these impacts and their ability to restore the landscape when mining is finished.

A recent survey of Canadians found that a substantial majority believed that there are more benefits than drawbacks for Canada from oil sands development, but 35 percent of Canadians saw more drawbacks than benefits.* Canadians seek a balance between the economic benefits of oil sands development and the environmental impacts of that development.

Greenhouse Gas Emissions

Key question: How do the GHG emissions of Canadian oil sands compare with other sources of crude oil? Is current data on GHG emissions transparent enough to support the adoption of sound public policy?

Why it matters: Canadian oil sands face a greater risk from climate change regulations because their GHG emissions are greater than many, but not all, sources of oil consumed in the United States. Transparent reporting requirements for all energy producers would ensure that all sources of liquid fuel, including oil sands, are considered fairly.

*Harris/Decima, *Oil Sands a Concern, but Yield More Benefits than Drawbacks for Canada,* Alberta, March 2, 2009.

Policies to reduce GHG emissions will put pressure on all producers of fossil fuels. However, Canadian oil sands face greater risk from such policies because of their relatively greater life-cycle GHG emissions compared with the average crude oil consumed in the United States.

Life-cycle assessments aim to quantify the GHG emissions of fuels along the entire value chain. For oil, this means accounting for all of the emissions that occur—from the production well through combustion of the final refined product. Key inputs for evaluating the life-cycle GHG emissions of petroleum fuels are

- the amount and type of fossil energy used in crude oil production
- GHG emissions resulting from vented or flared associated gas during crude oil production
- the amount and type of energy used in refining, which varies by refinery configuration, crude oil type, and refined product produced
- the distance and amount of energy used for transporting the fuel
- the carbon content of the refined product that is consumed

To evaluate the life-cycle GHG emissions of conventional and unconventional crude oils, we did not conduct our own original well-to-wheels study. Instead, CERA did a meta-analysis of 11 publicly available life-cycle studies and compared their results on an "apples-to-apples" basis. This meta-analysis assessment highlighted the wide range of estimates regarding emissions and energy use along the oil value chain and the need for more transparent data and accounting methods.

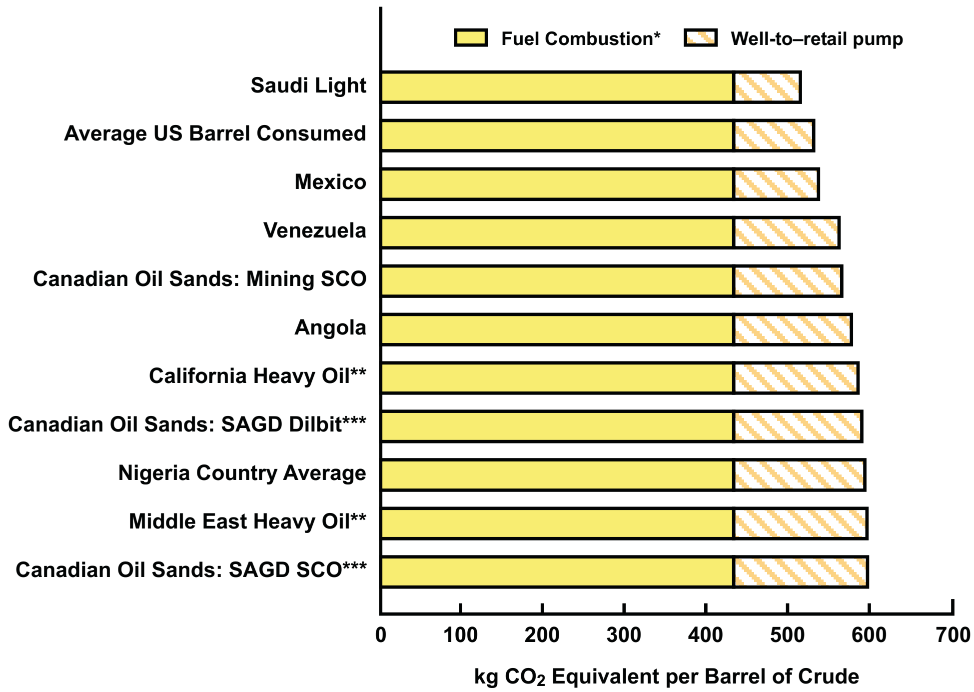
When GHG emissions are viewed on a life-cycle basis (well-to-wheels), the emissions released during the combustion of refined products (such as gasoline and diesel) make up 70 to 80 percent of total emissions.* The emissions associated with the final portion of the value chain are not related to the origin of the crude—for example, tailpipe GHG emissions from an automobile are the same whether the source of gasoline is Nigerian light crude, West Texas Intermediate crude (the famed WTI), or Canadian oil sands. Variability in life-cycle emissions among petroleum fuels occurs mainly in the well-to–retail pump portion of the value chain—the portion upstream of the vehicle tank (see Figure III-1).** Consequently, much of the public debate about oil sands emissions focuses on this segment although this constitutes a relatively small part of total GHG emissions.

Among sources of crude oil, emissions for the well-to–retail pump portion of the value chain differ because of varying energy requirements for crude oil production, upgrading, transport, and refining. However, in many life-cycle analyses, emissions for oil sands are compared against a single average "conventional crude oil." In reality the picture is more

*Well-to-wheels covers all GHG emissions from the production, processing, and distribution of oil and refined products and the combustion of refined products.
**Well-to–retail pump covers GHG emissions from oil production, processing, and distribution of refined products to the retail pump. It excludes combustion of refined products.

Figure III-1

Life-cycle Greenhouse Gas Emissions for Various Sources of Crude Oil



Source: Cambridge Energy Research Associates.
*The life-cycle GHG emissions estimate is based on a per barrel of crude basis, assuming an average carbon content. To convert this to a refined product basis, such as gasoline or diesel, additional assumptions would be needed to apportion well-to–retail pump emissions to individual refined products. This depends on the product slate associated with individual crude sources and refinery-specific configurations.
**Assumes steam-assisted gravity is used for production.
***Assumes a steam-oil ratio of 3.
Data source: Collected from a range of published reports that include th reports listed below, industry sources, and other published reports.
DOE/NETL: "Development of Baseline Data and Analysis of Life Cycle Gas Emissions of Petroleum-Based Fuels," November 2008.
McCann and Associates: "Typical Heavy Crude and Bitumen Derivative Gas Life Cycles," November 2001.
RAND: "Unconventional Fossil-Based Fuels: Economic and Environme 2008.
NEB: "Canadian Oil Sands: Opportunities and Challenges," 2006.
CAPP: "Environmental Challenges and Progress in Canada's Oil Sands
GREET: Version 1.8b, September 2008.
GHGenius: 2007 Crude Oil Production Update, Version 3.8.
Syncrude: “2007 Sustainability Report.”
Suncor: “2007 Report on Sustainability.”
Shell: “The Shell Sustainability Report, 2006.”
CERA /IHS data.
Report results were modified to represent a uniform system boundary a
When a single country is named, it represents an average country valu
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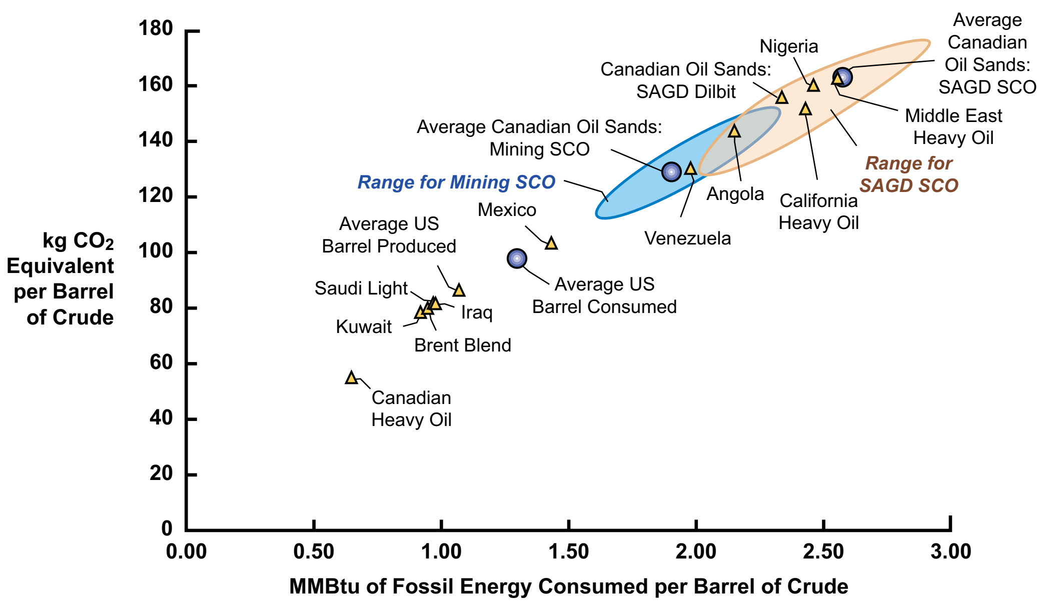
complex. Figure III-2 and Figure III-3 illustrate the well-to–retail pump GHG emissions for several sources of crude oil. The average well-to–retail pump emissions for crude oil consumed within the United States are also shown in Figure III-2.* Variability in GHG emissions arises from attributes of the crude oil itself and the oil field where it is produced. Important attributes include the heaviness of the crude oil (API gravity), the oil field's age, and the extraction technology utilized. For example, over the life of an oil field the energy consumed to extract a barrel of oil can increase more than four times, due to the need for more energy-intensive extraction techniques as the reservoir ages and the natural reservoir

Figure III-2

Well-to–retail pump Greenhouse Gas Emissions: A Comparison of Results from Published Reports

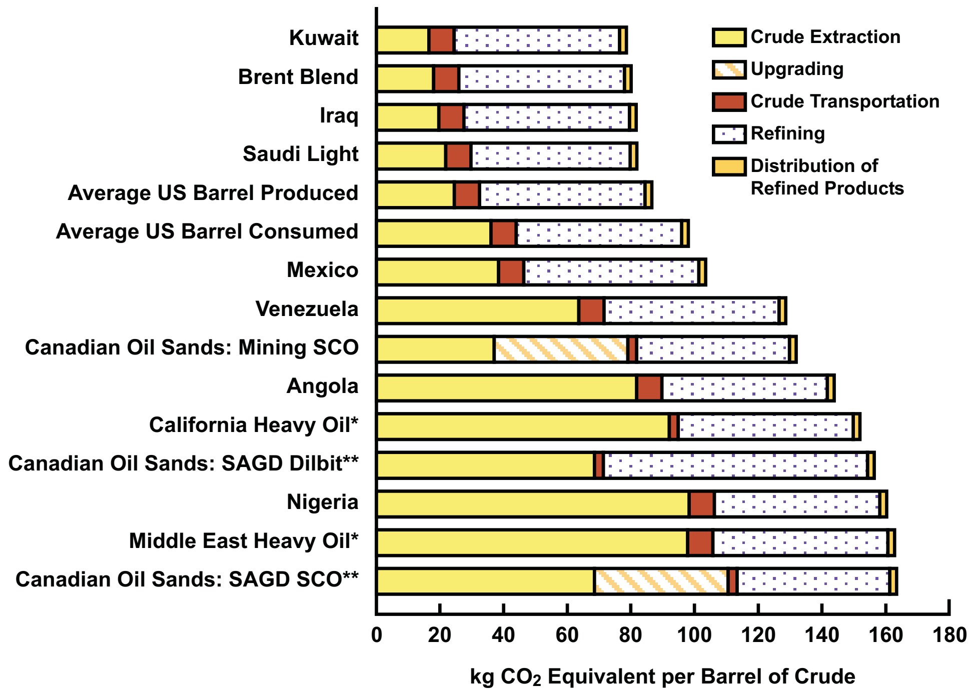


Source: Cambridge Energy Research Associates.
Data source: Collected from a range of published reports that include the reports listed below, industry sources, and other published reports.
DOE/NETL: "Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels," November 2008.
McCann and Associates: "Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles," November 2001.
RAND: "Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs," 2008.
NEB: "Canadian Oil Sands: Opportunities and Challenges," 2006.
CAPP: "Environmental Challenges and Progress in Canada's Oil Sands," 2008.
GREET: Version 1.8b, September 2008.
GHGenius: 2007 Crude Oil Production Update, Version 3.8.
Syncrude: "2007 Sustainability Report."
Suncor: "2007 Report on Sustainability."
Shell: "The Shell Sustainability Report, 2006."
CERA /IHS data.
Report results were modified to represent a uniform system boundary and units.
When a single country is named, it represents an average country value.
90107-9

*The average is specified in *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*, published by the US Department of Energy in November 2008.

Figure III-3

Well-to–retail pump Greenhouse Gas Emissions by Process



Source: Cambridge Energy Research Associates.
*Assumes steam-assisted gravity is used for production.
**Assumes a steam-oil ratio of 3.
Data source: Collected from a range of published reports that include the reports listed below, industry sources, and other published reports.
DOE/NETL: "Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels," November 2008.
McCann and Associates: "Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles," November 2001.
RAND: "Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs," 2008.
NEB: "Canadian Oil Sands: Opportunities and Challenges," 2006.
CAPP: "Environmental Challenges and Progress in Canada's Oil Sands," 2008.
GREET: Version 1.8b, September 2008.
GHGenius: 2007 Crude Oil Production Update, Version 3.8.
Syncrude: "2007 Sustainability Report."
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Shell: "The Shell Sustainability Report, 2006."
CERA /IHS data.
Report results were modified to represent a uniform system boundary and units.
When a single country is named, it represents an average country value.
90107-27

pressure declines. GHG emissions from the refining of crude oil can also vary by as much as 15 percent, depending on the heaviness of the crude oil processed and the complexity of the refinery.

GHG emissions associated with Canadian oil sands are generally higher than the average crude consumed in the United States because a significant amount of energy, typically natural gas, is used to extract the bitumen from the sand and upgrade it. Bitumen does not flow naturally and requires energy to be upgraded from a low-value solid to a high-value liquid fuel. However, Figure III-2 also highlights other sources of crude oil with high well-to–retail pump GHG emissions: Venezuelan heavy crude oil, Nigerian crude oils, and crude oils from mature assets that require steam for enhanced oil recovery.* This last group includes domestic resources such as California heavy oil and certain fields in the Gulf of Mexico and the Middle East.

The range of GHG emissions associated with Canadian oil sands development is quite large (see the shaded area on Figure III-2). Some analyses have asserted that Canadian oil sands have well-to–retail pump emissions many multiples higher than the average crude oil consumed in the United States. This is not true of the typical or average oil sands development or even of the more energy-intensive oil sands projects. For example, CERA's comparison of publicly available life-cycle analysis studies found that fuel produced from oil sands mining has average well-to–retail pump emissions 1.3 times the average for fuel consumed in the United States. Similarly, fuel produced from oil sands utilizing steam-assisted gravity drainage (SAGD) has average well-to–retail pump GHG emissions about 1.7 times larger than the average fuel consumed in the United States today. SAGD tends to have higher life-cycle GHG emissions than mining operations because of the significant amount of steam that must be produced for in-situ extraction.

The well-to–retail pump comparison shown in Figure III-2 makes GHG emissions from oil sands and other high-emitting crude oils appear quite large, but the difference between oil sands and the average crude consumed in the United States is significantly smaller when full life-cycle, well-to-wheels emissions are shown (see Figure III-1). Fuel produced from mined oil sands has about 5 percent greater well-to-wheels emissions than the average fuel consumed in the United States. Similarly, fuel produced from a SAGD project with a steam-oil ratio (SOR) of 3 has life-cycle emissions about 15 percent greater than the average fuel consumed in the United States.

Evaluating and comparing the life-cycle GHG emissions of fuels is a very complex process given the differences in the data used and in the types of inputs considered. Averages attained from rules of thumb or broad assessments can be helpful for general discussion, but they are not nearly specific enough to support sound public policy. More accurate measurement, verification, and reporting requirements are important components of policy development and implementation. For example, nearly all fossil fuel power plants in the United States have continuous emissions monitoring systems installed. These systems provide hourly data on a unit-by-unit basis and are likely to play an important role in tracking GHG emissions and costs for the power sector. To ensure the integrity of any future emissions regulatory regime, similar reporting requirements may emerge for the oil and gas sectors.

Furthermore international data must be accurate and verifiable. Without such a guarantee, Canadian oil sands could be unduly penalized for being more transparent about their GHG emissions. Policies that limit GHG emissions are likely to be costly. If future policies target life-cycle emissions, having accurate information will be crucial. Otherwise, policies that seek to reduce emissions could instead shift emissions to countries or sectors with mischaracterized levels of GHG emissions.

*GHG emissions of Nigerian crude oils are higher than many other sources because of the venting and flaring of associated natural gas during production.

Regardless of the comparison to other forms of energy, total GHG emissions related to the oil sands will rise as production increases. In all three of CERA's scenarios, production rises, although to varying degrees. In addition, the pace of efficiency gains (such as lower SORs) and the commercial success of carbon-mitigation technology will influence how steeply oil sands–related GHG emissions rise. The commercial development of oil sands has involved major technological innovation. Future development will almost certainly place significant emphasis on reducing GHG emissions.

Water Use and Availability

Key questions: How does the water use for production of Canadian oil sands compare with that for other sources of liquid fuels? Is enough water available to support current and future oil sands production?

Why it matters: Water is a critical input to oil sands production; and protecting the ecology of the Athabasca River and preventing groundwater depletion are also crucial.

The water use of oil sands projects has become a contentious issue, and oil sands are frequently identified as a water-intensive resource. However, oil sands are not alone in their water intensity; many types of energy production use a great deal of water. Figure III-4 depicts the water use of several liquid fuel and electricity production methods on an equivalent energy basis. Net water use in oil sands production today averages about four barrels of water per barrel of bitumen for mining operations and 0.9 barrels of water per barrel of bitumen for in-situ production.* Conventional oil uses about 0.1 to 0.3 barrels of water per barrel of oil produced, while oil produced through enhanced oil recovery can use up to 70 barrels of water per barrel of produced oil. Oil alternatives can also be water intensive: ethanol produced from irrigated crops such as corn can use more than 300 barrels of water per barrel of ethanol, and coal-to-liquids can use ten barrels of water per barrel of finished product.**

From an environmental perspective, adequate local water availability for oil sands production is more important than the amount of water used per barrel produced. The water intensity and rapid growth of oil sands production raises the question of whether there is enough water available to meet the industry's current and future needs without causing environmental damage.

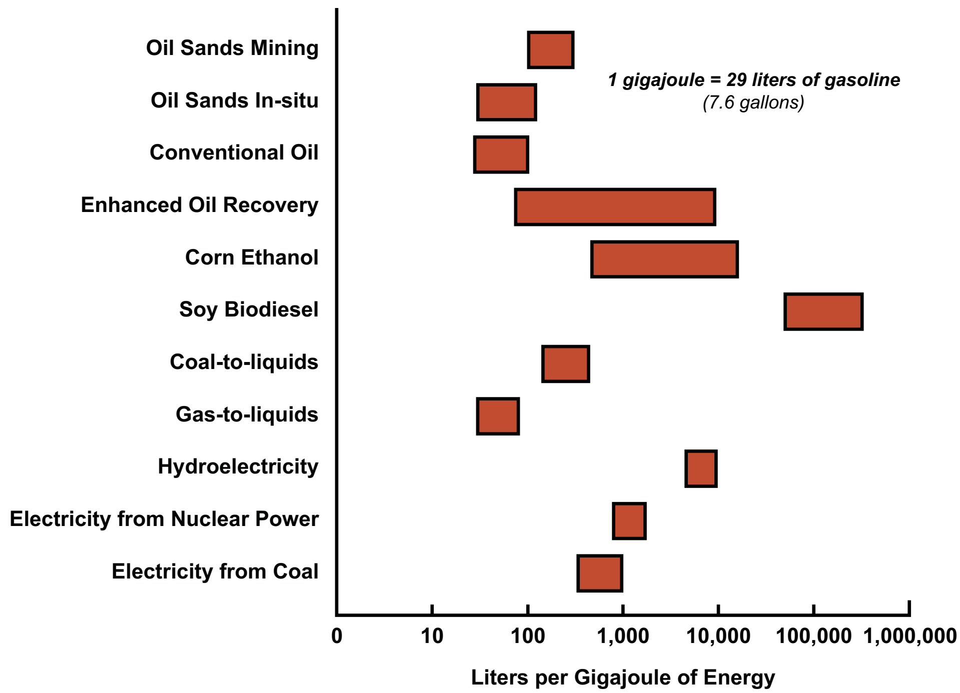
Mining Water Use

Water for oil sands mining and local upgrading comes primarily from the Athabasca River, with additional volumes from site runoff and mine dewatering. All water that contacts mining-affected areas is held on site, including process water and runoff due to precipitation. No

*Net mining water use includes water from site runoff and mine dewatering, in addition to water from the Athabasca River. River withdrawals are approximately 2.5 barrels of water per barrel of bitumen.
***Thirsty Energy: Water and Energy in the 21st Century.* World Economic Forum, in partnership with Cambridge Energy Research Associates, 2009.

Figure III-4

Life-cycle Water Use of Various Energy Sources



Source: Cambridge Energy Research Associates, US Department of Energy.
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water is intentionally released back to the Athabasca River.* The Athabasca River originates in Jasper National Park and flows north through the oil sands region to the Peace-Athabasca Delta and into Lake Athabasca. Its waters then flow through the Slave and Mackenzie Rivers into the Arctic Ocean. The Peace-Athabasca Delta is one of the most important nesting and migration staging areas for waterfowl in North America and is mostly protected by Wood Buffalo National Park.

The Athabasca River is seasonal with low winter flow—the average flow from April through November is nearly five times the average flow from December through March. Thus, oil sands water consumption during the winter is of particular concern, although maintaining high flow during the summer is also important to ecosystem health. Phase I of the Athabasca River Water Management Framework, implemented by Alberta Environment and the federal Department of Fisheries and Oceans in July 2007, sets limits on water withdrawals from the river to minimize negative effects on the ecosystem. At no time may withdrawal by all users, including oil sands, exceed 5.2 percent of median river flow. An instantaneous withdrawal limit of 15 cubic meters (m^3), or (3,960 gallons) per second is also in place during low-flow conditions in the winter, and a limit of 21 m^3 (5,548 gallons) per second is in place

*Some process-affected water may reach the Athabasca River because of seepage from tailings ponds, as discussed in a later section.

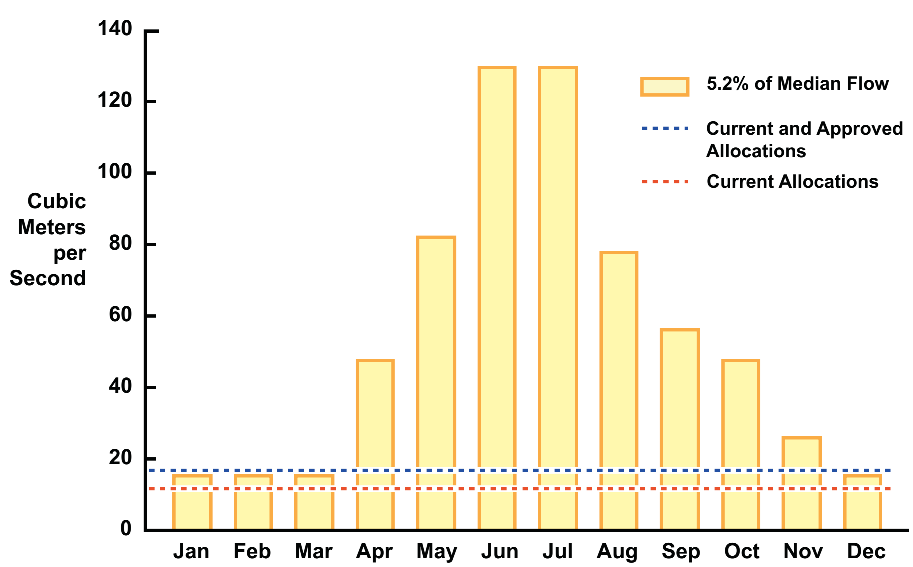
at all times. To date none of these limits have been binding on oil sands operators, but the amount of water allocated to users of the Athabasca is approaching these withdrawal limits (see Figure III-5). A second phase of the river management framework process is ongoing. The withdrawal limitations in place today will be reviewed and possibly adjusted no later than September 2010.

Projects planned for the future will allocate on an annual basis more river withdrawals than can be sustained during the winter months (see Figure III-5). Water is allocated from the river based on a total level of annual withdrawal. However, withdrawal limits during the winter will prevent operators from withdrawing water at their allocated average flow rate, as shown in Figure III-5. Thus, new mines under construction include facilities to store water during the summer months to allow continued operation when water flow from the Athabasca is restricted. Better management of mining waste will also reduce the amount of water required from the Athabasca River, as described in the following section. Finally, the volume of water that the mines actually use today is less than the allocated volume (see Figure III-6). The amount of water that the mines use changes over time, with especially high water use during expansion and start-up of new portions of the mine.

In the high growth Barreling Ahead scenario the mines are likely to use nearly all of their allocated water, and water storage will be particularly important. Production growth is lower in the New Social Order and Deep Freeze scenarios, with a corresponding decrease in stress on the Athabasca River and the need for water storage.

Figure III-5

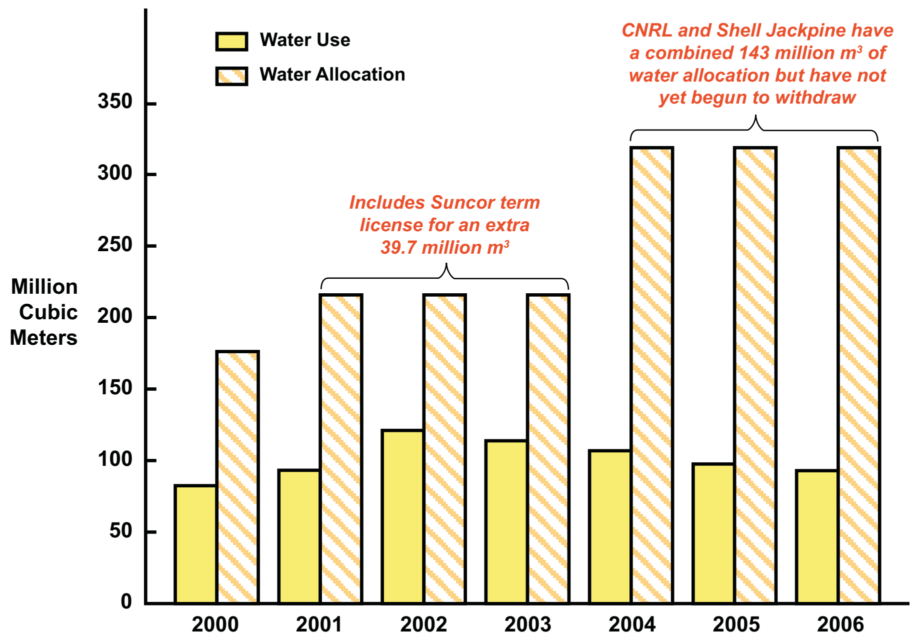
Athabasca River Flow:
5.2 Percent of Median Flow Compared to Allocated Withdrawals



Source: Cambridge Energy Research Associates;
water flow and allocation data from Alberta Environment.
90107-10

Figure III-6

Oil Sands Mining Actual Water Use and Allocation from the Athabasca River



Source: Cambridge Energy Research Associates; water use and allocation data from Alberta Environment.
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In-situ Water Use

Groundwater is the primary water source for in-situ oil sands production. The amount of water used for in-situ production depends on the amount of steam injected into the ground per volume of oil produced, known as the SOR, and the percentage of that water that can be recovered and recycled. The amount of water used in in-situ oil sands extraction has been decreasing over time. Operators have a strong incentive to decrease their water use and SOR because these changes in turn decrease their water treatment and steam production costs.

Use of salty water from deep aquifers, known as brackish groundwater, is becoming more common, but it has benefits and drawbacks. Using brackish water conserves freshwater resources for other uses, such as irrigation or drinking. Withdrawing groundwater from deep brackish aquifers also does not require a permit, although the volume withdrawn must be reported to Alberta Environment. On the other hand, brackish water requires more treatment than fresh to be used for oil sands production, because the silica, hardness, and salinity of the brackish water foul the steam-producing boilers. Use of brackish water thus results in higher water treatment costs, greater energy use, and greater amounts of waste generated by the water treatment process. A draft directive from the ERCB and Alberta Environment regulates water recycling in in-situ production, requiring a greater proportion of produced water to be recycled if only freshwater is used than if both fresh and brackish water are used.

Availability of groundwater, both brackish and fresh, for oil sands operations should not be taken for granted. The hydrogeology of freshwater aquifers in the oil sands area is complicated and poorly understood because of their hydraulic connection to the wetland environment of the boreal forest. These shallow freshwater aquifers are renewable, meaning that they will recharge from precipitation and surrounding water bodies when pumping ends. Determining the rate of water withdrawal from these aquifers that does not damage the surrounding wetland environment is challenging, however, and is currently under study. Deep brackish groundwater is sometimes referred to as “fossil water.” This water source is vast—there is much more brackish water in the oil sands area than there is bitumen—but once it is removed from the earth it will not recharge. Alberta Environment has several studies under way on groundwater in the oil sands region, including a study to examine the quality and availability of fresh and brackish groundwater in the region ranging from Fort McMurray south to Cold Lake, where a great deal of SAGD development is taking place. The hydrogeology is not consistent across the region, and in some areas brackish water sources are likely to be hydraulically connected to less saline water closer to the surface.

Each individual project that relies on groundwater (either fresh or brackish) performs pumping tests prior to development to determine whether the local water source is adequate to meet the project’s needs. Water availability and appropriate pumping rates are site specific. A lack of a suitable source of groundwater could occur for some leases in any of the three scenarios. However, groundwater use for in-situ production is of particular concern in the Barreling Ahead scenario, where nearly four times more water than is used today will be needed, despite decreasing SORs. Some operators may have to find creative solutions to meet their water needs, perhaps including finding water sources outside their lease. This process could be more difficult when oil sands development is denser and more projects are relying on the same aquifers, as is likely to occur in Barreling Ahead.

Tailings Accumulation and Management

Key question: How much waste material does the oil sands mining process create, and how is this waste managed?

Why it matters: Waste material and water management are closely related, since a great deal of water is retained in mining waste. Additionally, mining waste must be incorporated into the landscape during site reclamation.

Oil sands mines produce very large amounts of waste material. An average of two tons of oil sands ore is required to produce a single barrel of bitumen, although this varies with ore quality. Waste material generated is retained on the mine site. Ponds that contain water and solids from oil sands extraction currently cover approximately 140 square kilometers (55 square miles), the size of Staten Island, New York. Managing this waste material properly is essential to limiting the mines’ environmental impact.

Approximately 12 to 14 barrels of water are used to extract a barrel of bitumen from mined oil sand ore.* All of this water and the solids leftover from the extraction process are contained on site in tailings ponds, built above grade using dikes or below grade in mined-out areas. Sand sinks to the bottom of the ponds, while water and some remaining bitumen float to the top. Water from the top of the ponds is recycled back into the oil sands extraction process. The middle layer of the tailings ponds consists of a combination of clay, silt, and water known as fluid fine tailings. Clay and silt removed from the oil sands ore do not entirely separate from the water used in the extraction process. Instead, even after years of settling in the tailings ponds, the mixture only reaches 35 to 40 percent solids and has a consistency similar to pudding or yogurt. In approximately 40 years of commercial oil sands development, the industry has produced nearly 1 billion cubic meters (35 billion cubic feet) of these fluid fine tailings, and the ponds that contain these tailings and other mining waste cover nearly 30 percent of the area currently affected by mining.

Fluid fine tailings are an essential part of water management because they retain so much water, even after years of settling. For every barrel of bitumen produced, approximately four barrels of water are trapped in the resulting fluid fine tailings and settled sand, meaning that this water is currently unavailable for reuse. The water trapped in the tailings is one of the primary determinants of the amount of water that must be removed from the Athabasca River for operations, since this water is not recycled and must be made up from another source. Of the 12 to 14 barrels of water used in the extraction process for each barrel of bitumen produced, 8 to 10 barrels are recycled from the tailings ponds. The four barrels of water that remain trapped in sand and fluid fine tailings must be replaced, primarily with water from the Athabasca River, with the remainder from site runoff and mine dewatering.

Recovering water trapped in fluid fine tailings and allowing fluid fine tailings to become part of a trafficable landscape are the goals of a new ERCB directive. The directive requires that 50 percent of the clay and silt produced from the oil sands ore after July 2012 be removed from tailings ponds and made solid enough to support heavy equipment traffic. Less than half of the clay and silt in the oil sands ore ends up as fluid fine tailings; the remainder is associated with the sand layer at the bottom of the pond. Thus, the directive effectively means that all fluid fine tailings must be treated and made solid after 2012. If the technology works, accumulation of fluid fine tailings will end after this date, and a portion of the water trapped in fluid fine tailings will be available to be recycled into the oil sands extraction process.

Several engineering options are available to solidify tailings, including dewatering using centrifuges; treatment with gypsum, lime, polymers, or carbon dioxide (CO_2) (known collectively as consolidated tailings); or air drying. Dewatering tailings with centrifuges and consolidated tailings produce water that can be recycled into the extraction process, but this water is lost to the environment when tailings are air dried. The first commercial application of consolidated tailings is under way and nearing completion at Suncor’s Pond 5. At the same time, Suncor’s Pond 1 (the Tar Island dike) is being reclaimed using a variety of techniques in a treatment evaluation program expected to be completed in early 2010.

*Gross water use in mined oil sands extraction is 12 to 14 barrels per barrel of bitumen. Net water use is four barrels of water per barrel of bitumen. The difference between these numbers is recycled water.

Success at dewatering tailings is an important part of providing enough water for expansion of oil sands mining operations and reducing the amount of water needed from the Athabasca River. The extra water recovered from tailings helps to reduce the amount of water storage needed, especially in the Barreling Ahead scenario with its high mining growth and water needs. However, the high pace of growth in this scenario may make meeting the goals of the tailings directive challenging. In the New Social Order scenario we consider the possibility that a new directive requires oil sands operators to solidify tailings produced in the past as well, slowly eliminating fluid fine tailings from the landscape and providing more recycled water back to the extraction process. In the Deep Freeze scenario low oil prices reduce the availability of funding for tailings research, and advancement in treatment technology proceeds slowly.

Tailings Pond Toxicity and Regional Water Quality

Key question: How toxic are the tailings ponds, and what impact do they have on wildlife and water quality in the region?

Why it matters: Any leakage from the tailings ponds is likely to flow into the Athabasca River, toward Lake Athabasca and sensitive ecosystems downstream. Additionally, the tailings ponds are hazardous to waterfowl that land there.

Water deposited in the tailings ponds has been found to be toxic to aquatic life in assays involving fish and microorganisms, but the toxicity decreases over time. Naphthenic acids removed from bitumen during the extraction process are the primary source of this toxicity. Naphthenic acids tend to dissolve in water during the extraction process, rather than moving with the bitumen or adhering to sediment. Thus, they concentrate in tailings water as it is recycled through the extraction process. Tailings pond water also contains several other organic and inorganic substances that exceed ambient water quality guidelines issued by the Canadian federal government (the Canadian Environmental Quality Guidelines for protection of aquatic life) or the Alberta government (maximum discharge limits from the Environmental Protection and Enhancement Act), including benzene, phenols, toluene, polycyclic aromatic hydrocarbons, ammonia, aluminum, arsenic, copper, cyanide, and iron. Tailings pond water is also saltier than surrounding surface water. These water quality standards are not directly applicable to the oil sands water, because the sensitive aquatic species that these guidelines are designed to protect do not live in the tailings ponds, and the water is not directly released to the environment (except through seepage, as described below). Additionally, the toxicity of the water decreases slowly over time as organic compounds degrade, with some studies showing a much lower level of toxicity after about ten years.

Leaking from the tailings ponds is a matter of concern, particularly since several of the ponds are very close to the Athabasca River. Tailings ponds are generally designed with secondary containment structures to capture water that escapes the pond and send it back. Suncor's Tar Island dike provides an example of secondary containment in a pond built above grade using a dike. The dike was constructed using tailings sand and contains drains to allow water seeping through the sand to be collected and pumped back into the pond. At the end of the dike a ditch also collects runoff water that is pumped back into the pond. Tailings ponds constructed below grade in mined out areas often have wells that intercept shallow groundwater that may contain seepage from the pond and pump the water back into the pond. An additional factor that minimizes seepage from the ponds is the low hydraulic conductivity of the clay in the fluid fine tailings at the bottom of the ponds.

Despite these precautions, the tailings ponds are unlined earthen structures and are not completely contained. Some water seeps through the ponds and into the environment through groundwater. However, measuring the volume of this seepage is difficult, and no public data exists about tailings pond seepage. Alberta Environment has monitored groundwater quality in the region of the oil sands mines for some time, requiring each operator to provide an annual groundwater monitoring report. Additionally, Alberta Environment is studying the water balance in the region to better understand water flows and the extent of pond seepage.

The Regional Aquatics Monitoring Program (RAMP) has been monitoring water quality in the Athabasca River and surrounding lakes since 1997, including measuring water quality parameters, fish populations, and the health of benthic invertebrate communities. The purpose of the program is to monitor the environment in the oil sands area for evidence of change due to industrial activity, and its members include oil sands operators, agencies of the provincial and federal governments, and representatives of Aboriginal groups. The monitoring program has not found significant regional changes in aquatic resources related to oil sands developments or tailings pond seepage. Local changes in water quality have occurred due to permitted activities, including creek diversions and the discharge of treated domestic wastewater.

The RAMP was criticized in a 2004 peer review as inadequate to detect change in the Athabasca River watershed. However, the program has been strengthened since that time, with more monitoring sites added, more consistency in monitoring sites, and improved detection limits for important contaminants, such as naphthenic acids. A second peer review due to be completed in 2010 will shed additional light on the program’s effectiveness. Over time, additional data from Alberta Environment and RAMP may provide a better understanding of whether and how humans and wildlife are exposed to tailings pond seepage. At this point, very little is known.

The surface layer of bitumen found on most tailings ponds is an acute threat to wildlife. News reports of more than 1,000 ducks dying on a tailings pond in April 2008 brought this issue to the forefront. The ducks died from being coated with bitumen, not because of any other toxic substance in the ponds. Mine operators employ several mechanisms to deter waterfowl from landing on the tailings ponds, including cannons, scarecrows, and decoy predators. Operators also skim and reclaim bitumen from the surface of the ponds.

Human Health Impacts of Oil Sands Development

Key question: What impact does oil sands development have on human health in the immediate area and downstream?

Why it matters: Researchers are concerned about patterns of chronic disease in communities downstream of the oil sands region, particularly in Fort Chipewyan.

Fort Chipewyan is an isolated community located 280 kilometers (174 miles) north of Fort McMurray. The town is located on the shores of Lake Athabasca, near the Peace-Athabasca Delta and adjacent to Wood Buffalo National Park. The population of about 1,200 consists predominantly of Aboriginal people, including Cree, Chipewyan, and Métis.

Several doctors and nurses that serve Fort Chipewyan observed a number of cases of chronic disease in the community, including diabetes, cancers of the blood and liver, autoimmune diseases such as lupus and Graves disease (a disease that causes overactivity of the thyroid gland), and kidney failure and raised concerns about a potential environmental cause. Local residents also describe changes in the health of fish and wildlife that they catch and hunt, including deformities and changed taste and texture of meat. These changes could be due to pollution or due to stress on the wildlife population from other sources, such as changes in the food web. Many residents of Fort Chipewyan rely on fishing, hunting, trapping, and gathering for much of their food, making them particularly vulnerable to environmental contaminants.

Multiple studies have been conducted on the health of Fort Chipewyan residents, but their conclusions have been inconsistent. Alberta Health and Wellness concluded in 2006 that overall cancer rates in Fort Chipewyan were not higher than in the rest of Alberta.* The report did find elevated rates of Graves disease, kidney failure, and blood cancers (despite the finding that overall cancer rates were not elevated). Subsequently, the Alberta Cancer Board released a study in 2009 that came to the opposite conclusion on cancer, stating that cancer rates in Fort Chipewyan are higher than would be expected statistically.** Community leaders in Fort Chipewyan rejected the results of both studies, stating that both used incomplete data and did not adequately engage with community members. The Nunee Health Board, which is responsible for the health of the community on behalf of Health Canada, commissioned another study, completed in 2007.*** This study found arsenic, mercury, and polycyclic aromatic hydrocarbons in water and sediment at levels of concern, and concluded that the concentrations of these contaminants were rising. The study did not focus on a statistical analysis of cases of illness, but instead suggested that a more robust environmental monitoring program is needed to understand the health risks faced by residents of Fort Chipewyan and to better protect this population.

Linking incidences of illness back to an environmental source is a difficult exercise. The small population in Fort Chipewyan adds to the difficulty, since the small sample size makes determining the statistical significance of disease difficult. Additionally, the oil sands are not the only industry that adds to the pollution load in the area. Several pulp mills are operating along the Athabasca and Peace Rivers. Uranium City, Saskatchewan, where many uranium mines operated until 1983, is located across Lake Athabasca from Fort Chipewyan. Additionally, the Athabasca River naturally has oil sands along its banks, adding hydrocarbons to the river. Despite these complicating factors, continuing monitoring of the health of people

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*Alberta Health and Wellness, *Fort Chipewyan Health Data Analysis*, July 2006.
**Alberta Cancer Board, Division of Population Health and Information Surveillance, *Cancer Incidence in Fort Chipewyan, Alberta, 1995–2006*, February 2009.
***Timoney, Kevin P. *A Study of Water and Sediment Quality as Related to Public Health Issues, Fort Chipewyan, Alberta.* Treeline Ecological Research, Sherwood Park Alberta. November 11, 2007.

downstream of oil sands development and of environmental quality indicators is crucial to ensure that oil sands development occurs in a way that protects human health, animal health, and the environment.

Land Disturbance and Reclamation

Key question: At what pace will land disturbed by oil sands operations be restored? How will the ecology of reclaimed land differ from its predisturbance state?*

Why it matters: Canada's boreal forest is ecologically important, and landscape reclamation is important to local residents, particularly Aboriginal groups.

The natural state of land in the oil sands region is boreal forest. The boreal forest is the largest terrestrial ecosystem on earth, at one time stretching unbroken across the northern latitudes of North America, Europe, and Asia. The global range of boreal forest is larger even than the Amazon rainforest, and Canada has 1.3 billion acres of pristine boreal forest. Evergreen trees dominate the landscape, and 30 to 40 percent of the area is wetlands. The forest is home to many animals, including caribou, bear, wolves, moose, deer, and countless types of birds. Additionally, the boreal forest in Alberta provides recreation for local residents and traditional land use, such as hunting, trapping, and fishing, for Aboriginal groups.

Reclamation of Land Disturbed by Mining

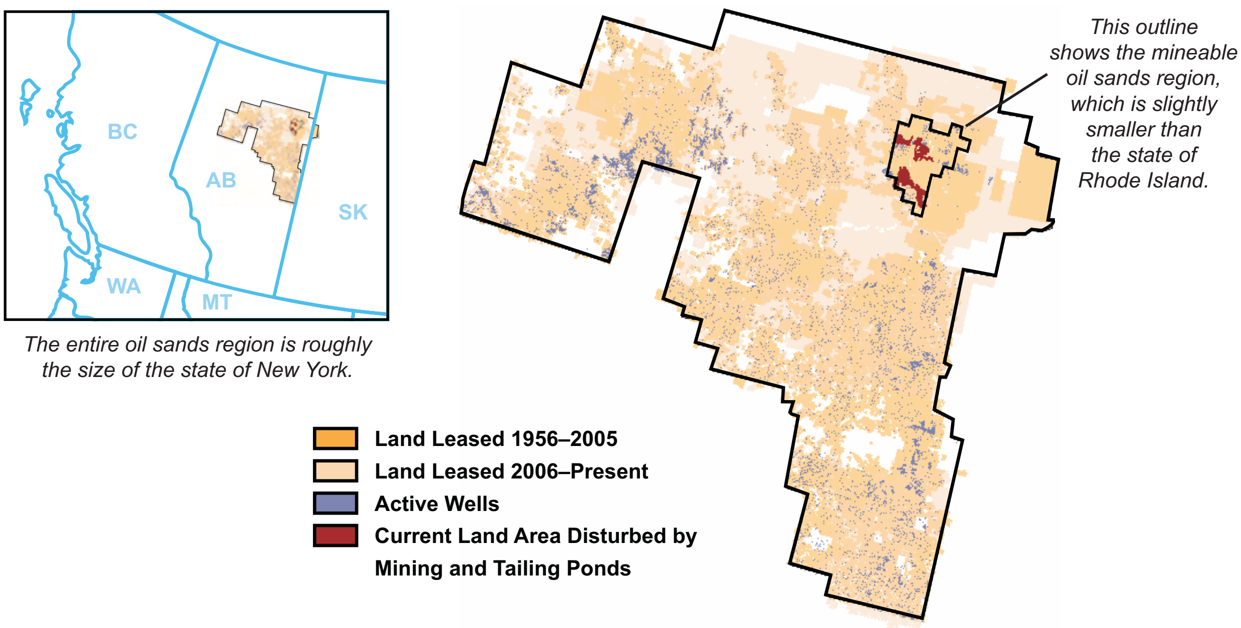
As oil sands production has increased, the amount of land disturbed by mining has grown rapidly (see Figure III-7). Mining operations result in a total loss of the ecological character of the disturbed land. Shell describes the impact this way in the application for its Muskeg River Mine expansion, "Effectively, a complete loss of soil and terrain, terrestrial vegetation, wetlands and forest resources, wildlife and biodiversity happens for this area for the period of operations." This description emphasizes the importance of the reclamation effort. The operators of mining facilities must submit detailed operation and reclamation plans to gain project approval, including baseline studies that capture knowledge on the region before mining begins. The plans describe the expected level of disturbance during operations, measures that will be taken to mitigate impacts, and details of the reclamation plan. For example, to comply with the Federal Fisheries Act, operators must include a plan to ensure no net loss of fish habitat during the operation of the mine and restoration of fish habitat after mining. The newest project approvals have included the creation of temporary lakes to provide fish habitat during mining operations. Despite the level of detail in the planning documents, the definition of "reclaimed" land and the pace of reclamation are open questions for many who want the land restored as closely as possible to its predisturbance state.

Even though oil sands mines have been active for more than 30 years, to date land reclamation has not kept pace with the rate of land disturbance. To some extent, the slow pace of reclamation is a result of the development arc of mining operations. Oil sands mines have long lives, and many years are required to finish mining in an area so that reclamation can begin. For this reason operators have had few opportunities to demonstrate successful

*Disturbed land is land where natural vegetation has been partially or totally cleared, wetlands have been drained, or the land has otherwise been changed from its natural ecological state.

Figure III-7

Land Leased and under Active Development in the Oil Sands Region



Source: Cambridge Energy Research Associates, IHS, ERCB.
Note: Comparisons to US states are to the total areas of the states, including land and water.
90107-18

How Much Land Is Changed by Oil Sands Development?

Alberta's entire oil sands region encompasses 55,000 square miles (142,000 square kilometers)—21 percent of Alberta's total area, or the size of the state of New York (see Figure III-7).

Approximately 200 square miles (518 square kilometers) are currently disturbed by surface mining, equivalent to 0.1 percent of Alberta's total area, 2 percent of greater Houston, 4 percent of greater Calgary, or an area large enough to contain four of the five boroughs (Manhattan, the Bronx, Brooklyn, and Staten Island) of New York City.

Of that disturbed land, tailings ponds cover 55 square miles (140 square kilometers), nearly 30 percent of the mining-disturbed area, roughly the size of Staten Island.

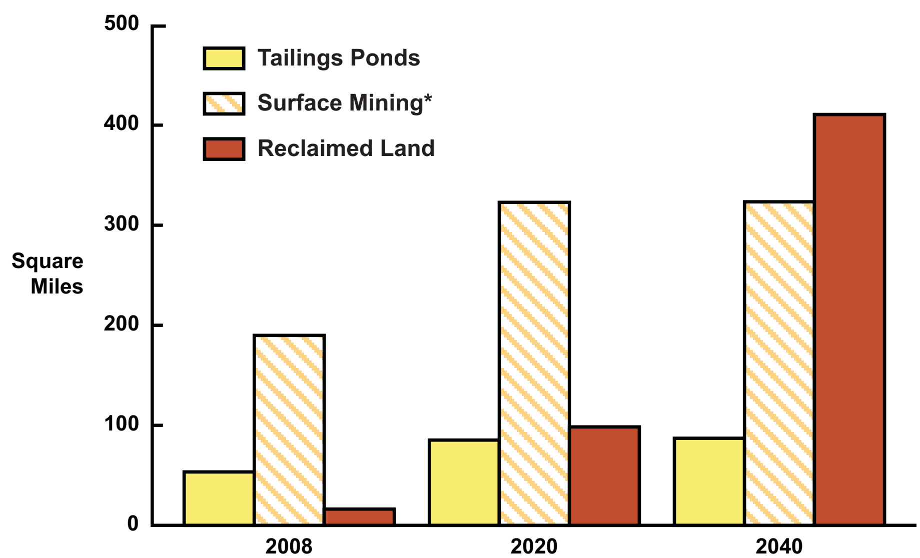
reclamation. Today about 8 percent of the land disturbed by surface mining is considered reclaimed, although only a very small parcel of land (about 1 square kilometer, or 0.4 square miles) has been certified as reclaimed by the Alberta government and released back to the public. Certifying the land requires allowing public access, and certifying more reclaimed land is not feasible today because it is located within the bounds of active mining operations.

According to approved reclamation plans for surface mines, the amount of reclaimed land will have increased sixfold by 2020 from its present level but will still be only one third the size of disturbed land (see Figure III-8). Between 2020 and 2040 the land area reclaimed increases significantly, while the area disturbed remains the same size. To date the pace of land reclamation, while slow, has been in line with expectations set forth in the projects' approved reclamation plans. However, the pace of tailings reclamation has not met the goals outlined in the original approvals. The tailings issue highlights that the approved reclamation plans are not binding, although the recent ERCB tailings directive will reduce the future rate of tailings accumulation.

Finding a balanced approach to land reclamation is a challenge. When an area is disturbed on the scale and extent of oil sands mining, the land is irreversibly changed. To what extent the reclaimed land will resemble its predevelopment state and whether the same plant and animal populations will return are still open questions. Prior to development, much of the mined area consisted of wetlands—bogs, fens, and swamps. Although collaborative research involving industry, academia, and local Aboriginal groups is under way to increase knowledge

Figure III-8

Oil Sands Mining Footprint and Reclamation Process



Source: Cambridge Energy Research Associates.
Data source: ERCB, reclaimed land data from Environmental Impact Assessments for new projects and 2006 reclamation plans for existing operations.
*Indludes tailing ponds.
90107-12

on restoring biodiversity in land reclamation, the science of restoring wetlands is in its infancy. Successful restoration of peaty wetlands (bogs and fens) is a particular challenge and has not been successfully demonstrated to date. Reclaimed land is likely to consist of a combination of highland forest and wetlands.

So-called end-pit lakes (EPLs) are a controversial part of mining reclamation plans. EPLs are engineered bodies of water built in mined-out areas, and at least 25 of them are included in the reclamation plans of existing and planned mines.* These EPLs are intended to contain fluid fine tailings and other mining waste at the bottom, topped by a layer of fresh water, and to become a permanent part of the landscape after reclamation. Ideally, the depth and shape of these lakes would prevent the water in contact with mining waste from mixing with clean water closer to the surface. However, no EPLs have been constructed to date, and the potential for these bodies of water to become active ecosystems that support plant and animal life is unknown.

The recently passed tailings directive should reduce the amount of fluid fine tailings produced and thus the number and size of EPLs needed to dispose of these tailings, bringing mine operators into compliance with their original reclamation plans. No technology has yet been proven to incorporate fluid fine tailings into a reclaimed landscape. Reclamation is likely to include a suite of technologies, including both dry tailings and fluid fine tailings stored in EPLs.

Reclamation of Land Disturbed by In-situ Production

Instead of completely clearing the land, in-situ development consists of clearing parts of the boreal forest to site facilities required to produce bitumen. CERA estimates that the disturbed area of a SAGD project averages about 6 to 7 percent of the lease. This compares favorably to mining, but the land disturbance is larger than for conventional oil production, which disturbs about 4 percent of leased land, or natural gas, at about 2 percent.** Although SAGD uses horizontal drilling methods that drill as many as ten well pairs from a central pad, for the projects analyzed the land disturbance of SAGD projects is larger than for conventional oil or gas. Several reasons account for the difference.

- The size of the facility needed to generate steam and treat water is larger than a conventional oil battery or gas compressor station.
- Pipes for steam and bitumen in SAGD run aboveground, creating larger cleared paths than the underground pipelines used in conventional oil and gas production.
- SAGD sites in remote locations generally include support buildings and camps to house workers.

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*Not all of these mines will be built in all scenarios, so the number of EPLs actually built could be smaller.
**CERA estimated the extent of disturbed land using aerial photographs and project approval maps for selected sites: SAGD at Devon Jackfish, conventional oil from the Fletcher Leduc-Woodbend, and conventional gas from EnCana Strathmore.

About 18 percent of the total area of Alberta is leased for in-situ development. Because of the significant size and the pristine, undeveloped state of much of the land in the leased area, stakeholders are concerned about the cumulative impacts of potential projects. Fragmentation of the forest caused by in-situ oil sands production is believed to decrease the populations of some animal species, such as lynx, wolves, and caribou, which tend to leave an area when human development occurs. However, the extent of the disturbance is difficult to quantify since data on many species populations in remote regions are difficult to gather. The Alberta Biodiversity Monitoring Institute recently concluded a study on the status of birds and vascular plants in the Lower Athabasca region.* The study found that 7 percent of the land in the area had been altered by human activity (including agriculture and forestry in addition to energy development), and the biodiversity of the region for birds and vascular plants had declined 6 percent. The study did not measure the impact on mammals, but it is an important step in establishing biodiversity data for the region.

Reclamation requirements for in-situ sites are typically outlined in each projects' Environmental Impact Assessment (EIA).** The EIA outlines information regarding the baseline conditions on the lease prior to development, details regarding the salvage of materials such as soil and timber and plans for restoring the topography after development. These reclamation goals will be much easier to reach compared to mining reclamation because of the much smaller scale of degradation. Much of the leased land remains boreal forest during site operations.

What Will the Future Bring?

Reclamation is a major focus of the New Social Order scenario. EPLs are eliminated because legacy tailings are treated to become trafficable surfaces. Research advances in the science of wetlands restoration and strong pressure from the Alberta government and Aboriginal groups keeps reclamation moving forward. On the other hand in the Barreling Ahead scenario the pace of reclamation is unlikely to keep up with the rapid pace of production growth and land disturbance. Reclamation is also likely to be slow in the Deep Freeze scenario, but for different reasons. The low oil price environment leaves little extra cash for reclamation activities, although fewer projects are developed in this scenario and thus less land is disturbed.

TECHNOLOGY ISSUES

Continuing technology development is a critical issue in reducing costs and decreasing the environmental footprint of development. Research is under way, and new technologies are on the horizon that could help the oil sands meet the cost and environmental performance requirements of future energy markets.

*Alberta Biodiversity Monitoring Institute, *The Status of Birds and Vascular Plants in Alberta's Lower Athabasca Planning Region 2009 Preliminary Assessment, February 2009.*

**Projects that produce less than 12,600 barrels per day are not required to produce an EIA and must follow the Alberta government's *Guide to Reclamation for Well Sites and Associated Facilities for Forested Lands in the Green Area.*

Opportunities to Reduce GHG Emissions

Key question: How much can oil sands operators decrease their GHG emissions, and at what cost?

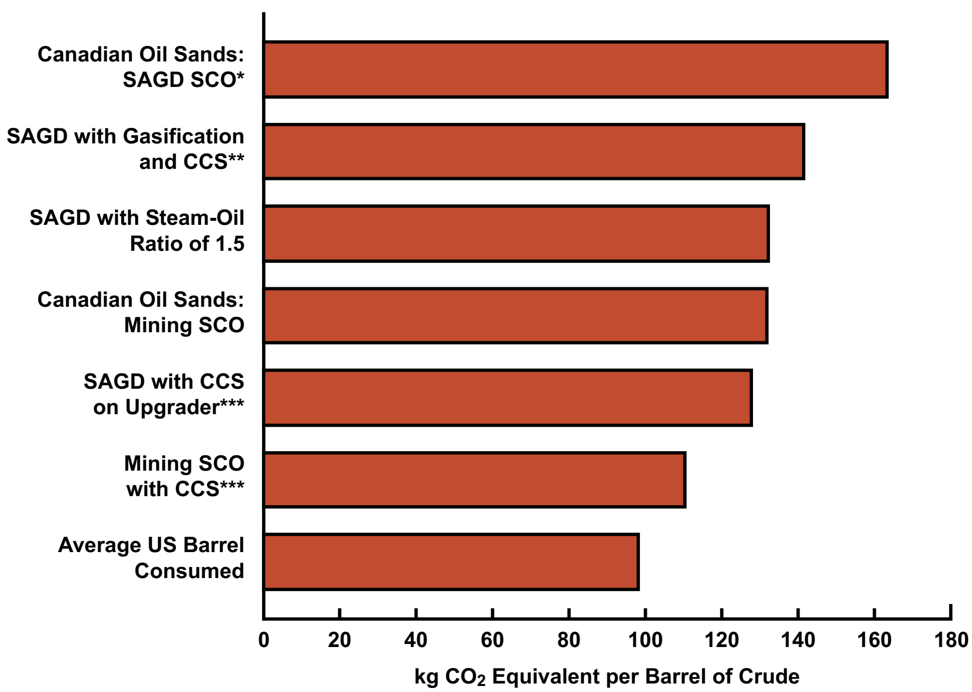
Why it matters: Strong climate change policies could substantially add to the cost of oil sands' GHG emissions or require that these emissions be reduced.

Canadian oil sands have greater life-cycle GHG emissions than the average crude oil consumed in the United States. Future emissions policies could put new pressure on oil sands operations to reduce their GHG emissions. Improved efficiency and carbon capture and storage (CCS) are two options that could reduce GHG emissions associated with oil sands production.

In the near term, improving the efficiency of oil sands production presents the most cost-effective and technologically feasible opportunity for reducing emissions for both mining and SAGD (see Figure III-9). For example with mining operations, improved process reliability to

Figure III-9

Well-to–retail pump Greenhouse Gas Emissions: Opportunities to Reduce Emissions from Canadian Oil Sands



Source: Cambridge Energy Research Associates.
*Assumes a steam-oil ratio of 3.
**Assumes that the upgrader is powered by gasifying petroleum coke instead of natural gas. Additional syngas produced from the upgrader is used in SAGD to produce the needed steam for crude production, displacing SAGD natural gas consumption.
***CCS on SMR unit in the upgrader. No other GHG emissions are captured.
90107-13_2404

maximize upgrader throughput can help to lower energy consumption per unit of processed fuel and thus lower life-cycle emissions. Opportunities also exist in SAGD operations to reduce GHG emissions; for example, improving the SOR of SAGD production from today's average of 3 to 1.5 would reduce well-to–retail pump GHG emissions by about 20 percent. Achieving an SOR of 1.5 would require new technology, such as the use of solvents, but this ratio could reduce emissions by over 1 million metric tons per year for a 100,000 barrel per day (bd) SAGD operation. Even with an SOR of 1.5, a SAGD operation would have greater life-cycle GHG emissions than the average crude consumed in the United States but would produce fewer emissions than the average crude produced today in Nigeria or Angola. Completely new extraction technologies, as described in the next section, have the potential to further increase the efficiency of in-situ oil sands production. However, these technologies are not yet viable.

CCS could also reduce the life-cycle emissions from oil sands production, but it will likely be at least a decade before CCS is commercially viable at the scale needed for the oil sands. Two CCS technologies that can be implemented at a practical scale are in the bitumen upgrading portion of the value chain.* The first option involves capturing a relatively pure stream of CO_2 from a steam methane reforming (SMR) unit used for hydrogen production. This form of CCS could reduce the emissions associated with upgrading by about 40 percent and the total well-to–retail pump emissions of synthetic crude oil by about 20 percent. Another CCS option involves capturing the CO_2 emissions from a bitumen upgrader that uses petroleum coke gasification instead of natural gas to produce the facility's energy. In this case well-to–retail pump emissions would decrease by about 15 percent compared with today's typical SAGD operation.**

Implementing CCS increases capital and operating costs substantially. Retrofitting an SMR unit for CCS can cost between $500 and $700 million for a 100,000 bd upgrading facility, and equipping a gasification plant for CCS is likely to exceed $1 billion, in addition to the $1.5–$2 billion cost of building the gasification plant. Translating these capital costs into dollars per ton of GHG abatement costs suggests that CO_2 prices (or taxes) would need to exceed $50 per metric ton of CO_2 for an SMR retrofit and nearly $100 per metric ton of CO_2 for CCS on a gasification plant in order to economically justify the additional expenses. Some studies find even greater carbon capture costs—in excess of $150 per ton. The technology is embryonic and cost estimates are based on early engineering estimates that vary widely. No matter which cost estimate one uses, for wide-scale adoption of CCS to be economic, CCS costs would need to decline significantly or CO_2 allowance prices (or taxes) would need to significantly exceed $50 per ton.

*There are other CCS options, such as using amine scrubbers to capture GHG emissions from SAGD boilers, but current cost estimates suggest this technology is further from implementation than the two options discussed here.
**In both examples CERA assumes that parasitic load from the CCS equipment increases energy use by about 30 percent, thus decreasing the impact of CO_2 capture. For the SMR retrofit example CERA assumes that 40 percent of the emissions associated with the upgrading portion of the value chain are captured. For the gasification example CERA assumes that 60 percent of emissions associated with both upgrading and steam creation are captured. Finally, in the case of the gasification unit, petroleum coke simply has much higher CO_2 emissions as a feedstock fuel compared with natural gas.

For successful commercialization of CCS, policies that go beyond putting a price on CO_2 emissions will be required to address CO_2 transportation (i.e., pipeline development), storage site licensing, storage liabilities, and monitoring requirements. Assuming that these barriers can be overcome, the geological storage opportunities in the Fort McMurray area appear to be limited, suggesting that a CO_2 pipeline connecting the Fort McMurray area to regions farther south will be needed.* The costs of such a pipeline combined with the need for collaboration among many operators to build the pipeline would further increase the barrier for CCS in oil sands.

CCS and improved efficiency present opportunities for reducing GHG emissions along the oil value chain, but their adoption will not necessarily lower the total emissions associated with oil sands production. For example, under a scenario where oil sands production continues to rise, the combined effects of CCS and improved efficiency would be unlikely to overcome the GHG emissions increase associated with increased production. In all three CERA scenarios oil sands production and GHG emissions continue to rise, but with the high carbon prices in the New Social Order scenario substantial reductions in GHG emissions per barrel occur even as aggregate emissions levels increase.

CCS and energy efficiency for oil sands must be considered in a wider context. More than 70 percent of GHG emissions associated with oil consumption occur during combustion of the final refined product. This portion of the value chain is largely outside the purview of oil and gas companies and lies instead with automobile manufacturers, consumers, and regulators through vehicle fuel efficiency. Furthermore, policies targeting economywide emissions are likely to encourage emissions reductions in many other sectors of the economy, many of which are likely to be less expensive to implement than reductions in the oil sands.

Improvements in Oil Sands Technology

Key question: How could oil sands production technology improve in the future?

Why it matters: Technology improvements for both SAGD and mining could bring reductions in cost, GHG emissions, and water use, along with other environmental benefits.

Since the inception of the first commercial oil sands facility in 1967, the industry has made major technological strides in optimizing resources, reducing costs, increasing efficiency, and reducing its environmental impact. Innovation—led by industry, academia, and government—has reduced the extraction and processing costs of oil sands as well as reduced their environmental footprint, particularly in oil sands mining. The changing of mining equipment from drag lines and conveyors to shovels and trucks, the transport of oil sands ore in a water slurry (known as hydrotransport), and the reduction in the extraction temperature of the ore have all greatly reduced the energy intensity of oil sands mining. Although mining is relatively mature compared to in-situ production techniques, new technologies to manage fluid fine tailings will reduce water use and make reclamation easier.

*Geologists working in the region suggest that geological formations in central Alberta are more amenable to CO_2 storage than those near Fort McMurray.

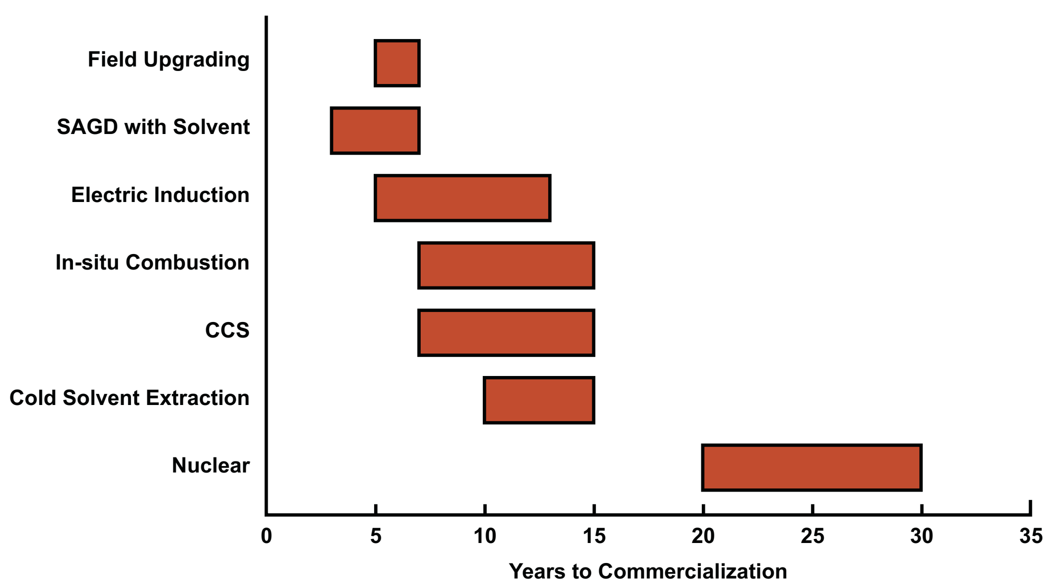
The development of SAGD technology was a major step forward in in-situ production technology. Incremental improvements in SAGD have already improved recovery and reduced costs and GHG emissions. Best-in-class SORs have already fallen from around 6, seven to eight years ago, to as low as 2.2 today, reducing energy use and GHG emissions. Optimizing the use of solvents (propane or butane) in SAGD processes could result in further reductions in the SOR, perhaps as low as 1.5. Reduction in SOR reduces the operating costs, natural gas demand, GHG emissions, land footprint, and water use of SAGD projects.

Future drilling practices will be less intrusive on the landscape as more wells are drilled on the same well pad and distances attained by horizontal drilling continue to increase. Continuous improvement will result from ongoing optimization of reservoir management, infill drilling, and improved steam distribution techniques. Better control of sand could result in higher operational efficiencies, leading to improved recoveries of bitumen. Downhole pumps already boost recoveries.

In addition to incremental improvements to existing SAGD technology, several technologies that are in various stages of development today have the potential for more radical changes in oil sands production. All of these, however, will have to be proven effective and economic at scale. Figure III-10 depicts an estimate of the availability timeline for a range of oil sands technologies.

Figure III-10

Current Estimated Timeline for Innovative Oil Sands Technologies



Source: Cambridge Energy Research Associates.
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- **Gasification technology** allows solid fuel (such as petroleum coke or asphaltenes) to be converted into a gaseous fuel that can power a turbine (applications: upgrading and in-situ).

- **Consolidated tailings and tailings dewatering and drying** allow fluid fine tailings to be converted to a surface solid enough to handle heavy equipment traffic (application: mining).

- **Pure solvent extraction techniques**, either hot or cold, could result in total replacement of steam, greatly reducing GHG emissions and water use and markedly increasing oil recovery. Cost implications would depend on solvent cost and availability, as well as achieving high solvent recycle rates (application: in-situ).

- **Field upgrading** uses small-scale units to "crack" a portion of the bitumen, producing some lighter petroleum products and a by-product fuel that can be used on site instead of natural gas to raise steam. Field upgrading reduces the viscosity of bitumen enough to allow it to be transported through pipelines without adding diluent. The lack of diluent and natural gas inputs could result in substantial operating cost savings when intergraded with an in-situ operation (application: in-situ).

- **In-situ combustion techniques** (often described as fire-flood processes) involve underground combustion of some bitumen, warming the reservoir enough to allow the remaining bitumen to flow. The process has the potential for lower capital costs, lower operating costs, less water use, and lower GHG emissions. Additionally, the bitumen is partially upgraded underground as the heavier fractions burn, and some variations of the technology incorporate a catalyst with the goal of further upgrading bitumen in the reservoir (application: in-situ).

- **Electric induction technologies** involve introducing electric energy into the oil sands through an inductor and an alternating magnetic field generated around the inductor. This process heats the bitumen and produces higher recoveries when combined with steam injection. The benefits could include lower water consumption and energy use (similar to an SOR of 0.5 to 1 for SAGD), higher yields, lower GHG emissions, and flexibility to recover bitumen from reservoirs that are not ideal for current in-situ technologies (application: in-situ).

- **Nuclear power** could be used to produce steam and electric power in SAGD operations, but significant progress would be required in the development of small modular nuclear units. Small modular nuclear reactors that produce 30–100 megawatts-electric are currently under early development but are as yet unproven (application: in-situ).

New Social Order, with its high carbon price and focus on clean energy, brings about the most innovation in oil sands technology. Technological changes focus on reducing environmental impacts and GHG emissions, and include CCS, solvent extraction, in-situ combustion techniques, and small nuclear facilities. Technological changes in the Barreling Ahead scenario primarily come about to replace natural gas because of rising prices. These technologies include gasification for upgraders, using asphaltenes or petroleum coke as fuel, and technologies that do not require steam, such as solvent extraction and in-situ combustion techniques. Technological change in the Deep Freeze scenario focuses on lowering operating costs to survive in the low oil price environment. Technologies that take hold in this scenario include solvent extraction and incremental improvements to the SAGD process.

Government Investment Is Key to Improving Oil Sands Technology

Key question: How to pay to develop and improve oil sands technology?

Why it matters: Growth in oil sands production and improvement of environmental performance depend on technological advancement. Individual companies do not always have the resources or incentive to do the basic research required.

The federal and provincial governments led early research and investment in the oil sands. Carl Clark of the Alberta Research Council developed the hot water extraction process—the answer to unlocking the bitumen from the sand. Entrepreneurs established the first processing plants in the 1920s and later in 1940s, but the federal and the provincial governments stepped in to purchase these early plants when they became unprofitable. Even in more recent times, when the Syncrude project struggled with financing in 1973, the governments of Canada, Alberta, and Ontario became investors.

Government continues to play a vital role in oil sands innovation, but industry contributions to new technology have become more important over time. Development of in-situ technology was a true collaborative effort among industry, academia, and government. Roger Butler developed the idea for SAGD at the University of Calgary in the early 1980s, but it took collaboration between government and industry through the Oil Sands Technology and Research Authority (AOSTRA) to prove that Dr. Butler's idea could be commercially viable. Government-funded research today is conducted at the Alberta Energy Research Institute (AERI, formally AOSTRA); at CANMET, a federal research laboratory; and at universities in Alberta and beyond. However, as the oil sands have become a commercial enterprise, the mix of funding has changed. In the early days the government spent the majority of money, whereas today, the government spends about half as much as it did 15 years ago and industry contributes a much larger share. Moreover, today a strong bubbling of innovation comes from small entrepreneurs in addition to the large oil companies that continue to research new technology. New technology is also advanced through industry consortiums. For example, the Integrated CO_2 Network and the Alberta Saline Aquifer Project are two industry groups studying CCS.

Increasing oil sands production and decreasing the environmental impact of this production depends on a number of technological advances. Many potential advances will require the kind of basic research that individual companies do not have the resources or incentive to conduct. For example, researching CCS technology and providing the necessary infrastructure for CO_2 transport is too large an undertaking for any one company. Continuing government involvement in basic oil sands research will likely be critical to achieving the technological advances the industry needs. A key requirement for addressing the oil sands' environmental challenges is sustained government support for research and development across a broad range of technologies, not just CCS. The challenges and needs and the potential societal benefits fit the classic formula for government-supported research and development.*

*See the report *Energy R&D: Shaping Our Nation's Future in a Competitive World* by the US Secretary of Energy Advisory Board Task Force on Strategic Energy Research and Development, US Department of Energy, Washington DC, 1995.

CHAPTER IV: CERA'S OIL SANDS SCENARIOS

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WHY SCENARIOS?

> A long run view of history reminds us of the presence of changes, ruptures, and discontinuities. It should warn us against simply extrapolating from a brief period of a few years, and projecting the future as simply a continuation of the immediately lived and experienced past.
>
> —Professor Harold James, Princeton University, author of *The End of Globalization: Lessons from the Great Depression*

What are scenarios and why use them? Unlike forecasting, the scenario process does not attempt to foretell the one "right" future, but instead expands analysis to gain a broader and more systematic understanding of how several possible and plausible futures could unfold and the key forces shaping them. Forecasting exercises begin with factors that are assumed to be certain and extrapolates from them. Because of this, forecasts can unwittingly disguise uncertainties and conceal risks. They also often assume a greater predictability about the future than is in fact the case. Scenarios, by contrast, acknowledge uncertainties as a principal "building block" in determining the factors that could lead to a future that is different from the present. Scenarios encourage people to disengage from position, prestige, point of view, and established interests to think about the future in a more flexible way.

The scenario process is well suited to considering the future of the oil sands. Many factors shaping the future of the oil sands are uncertain and could plausibly unfold in several ways. There are also issues on which a wide range of views exists. Scenarios inject more perspective into the discussion about the future than a single line forecast. Scenarios illustrate worlds that *could* happen—not necessarily worlds that *should* happen.

The oil sands scenarios presented in this report draw from the three scenarios originally prepared for CERA's 2006 Multiclient Study *Dawn of a New Age*: *Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030*. The *Dawn of a New Age* scenarios outlined three very different worlds. One considered the impact of rising Asian economies on the world energy system. A second explored the repercussions of oil prices' attaining levels of $150 per barrel. A third imagined a severe global recession triggered by a financial crisis. In the three short years since those scenarios were completed, important elements of each of these very different worlds have become a reality for the world energy system. The rapidly changing and unpredictable nature of this short period of history underscores the necessity for stakeholders to think about the future in a broader way and to resist the inevitable human tendency toward simple extrapolation.

Growth in the Canadian Oil Sands: Finding the New Balance uses CERA's global scenarios as a starting point and backdrop, while drilling down into issues specific to the Alberta oil sands. This study presents three different outcomes for how the oil sands could be developed (see Table IV-1). These scenarios are intended to explore the potential boundaries for the development of the oil sands, taking into account the issues and uncertainties we have identified. They are by no means the only possible paths of development that could be

Table IV-1

Key Storylines of CERA's Long-term Oil Sands Scenarios

NEW SOCIAL ORDER. A global oil supply crisis leads to several years of oil prices above $100 per barrel. Alternative fuels and vehicles emerge and North American oil demand declines sharply. The emphasis of Canadian and US governments shifts decisively toward environmental regulation (especially carbon) and encouragement of green energy technologies.

BARRELING AHEAD. North American and world oil demand exhibit healthy growth on the back of a robust economic climate. World oil prices remain consistently strong. The Canadian government's emphasis is on maximizing oil sands development, including diversifying export markets and facilitating a more moderate cost environment. Efforts to regulate GHG emissions follow a "middle-of-the-road" path.

DEEP FREEZE. Global economic growth stagnates, and protectionism and antiglobalization sentiment dominate the political-economic landscape. Oil demand and oil prices remain depressed. There is little urgency or political appetite to implement GHG regulations.

Source: Cambridge Energy Research Associates.

envisioned. Indeed, it is possible that like CERA's global energy scenarios, the future will ultimately contain elements of all three scenarios. For this reason CERA does not assign probability to any scenario, but rather encourages stakeholders and business leaders to use these scenarios to think as broadly as possible about how they might adapt to a world that does unfold in expected ways—and a world of surprise and rapid, discontinuous change (see Table IV-2).

NEW SOCIAL ORDER SCENARIO: KEY INSIGHTS

Insight 1. A period of high prices may appear beneficial to the oil sands, but it sows the seeds of demand destruction and encourages more government support for alternative forms of energy. This could, in the long term, result in downward pressure on oil prices and higher costs for producing oil sands.

Insight 2. Long-term petroleum demand growth in North America is not assured, even with population and economic growth. Efficiency gains, consumer behavior changes, and inroads by alternative fuels could ultimately lead to a peaking of demand. This could result in stranded investments in the oil sands if productive capacity is not carefully calibrated with demand growth.

Table IV-2

Snapshot of Key Variables in CERA's Oil Sands Scenarios

	Barreling Ahead	New Social Order	Deep Freeze
			
Gross Domestic Product (GDP) Global Average Growth, 2009–35 (constant 2008 US dollars)	4.20%	3.80%	2.90%
North American Petroleum Demand Growth, 2009–35	1.6 million barrels per day (mbd) (+8%)	-1.8 mbd (-9%)	+0.5 mbd (+3%)
North American Biofuels Demand Level, 2035	1.7 mbd	2.7 mbd	1.2 mbd
Global Liquids Demand Growth, 2009–35 (includes biofuels)	+29 mbd (+35%)	+16.5 mbd (+19%)	+14 mbd (+17%)
West Texas Intermediate (WTI) Average, 2009–35 (constant 2008 US dollars per barrel)	$64	$77	$27
Henry Hub Average Price, 2009–35 (constant 2008 US dollars per million British thermal unit [MMBtu])	$10	$10.30 (net of carbon price)	$5
Average Capital Cost, Integrated Mine and Upgrader Alberta, 2009–35 (constant 2008 Canadian dollars per flowing barrel)	C$105,000	C$174,000	C$95,000
Downstream Product Split (2035)	61% Synthetic crude oil (SCO); 39% Bitumen	58% SCO; 42% Bitumen	45% SCO; 55% Bitumen
Upstream Product Split (2035)	51% Mine; 49% In situ	51% Mine; 49% In situ	43% Mine; 57% In situ
Oil Sands as a Share of US Total Crude Imports	37%	24%	23%
Oil Sands Production Capacity (2035)	6.3 mbd	3.0 mbd	2.3 mbd

Source: Cambridge Energy Research Associates.

Insight 3. The tension between the need for energy security and the desire for cleaner energy sources is unlikely to be completely resolved. By virtue of their size, the oil sands remain critical to total North American oil supply. Their importance will be magnified during disruptions of conventional oil supplies in the greater world oil market.

Insight 4. A regulatory framework focused on sustainable development and a price on carbon dioxide (CO_2) emissions could spur technological innovations that enable the oil sands to become a cleaner source of energy. This shift could be concurrent with a less frenetic pace of development, particularly when compared to the Barreling Ahead scenario.

Insight 5. Carbon capture and storage (CCS) is an option for reducing greenhouse gas (GHG) emissions from oil sands. However, capturing CO_2 is expensive, and geological constraints in the Fort McMurray area prevent CO_2 captured from oil sands operations from being stored locally. Industry collaboration will be required to build the pipeline network required to ship the industry's aggregated CO_2 volumes for sequestration in central Alberta.

Insight 6. Improvement in the management of tailings ponds, mining waste, and land reclamation—which accelerates in this scenario—is crucial for public acceptance and regulatory compliance of oil sands growth, since they are the most visible symbol of the oil sands' environmental cost.

Insight 7. The oil sands could benefit economically and environmentally from the deployment of gasification and CCS. However, these technologies are not commercial on a large scale today. To achieve commercial success, these technologies will require significant technological innovation, a steep decline in capital costs, and a high cost of carbon.

THE CLEAN ENERGY REVOLUTION: THE ECONOMIC AND ENERGY CONTEXT OF NEW SOCIAL ORDER

Energy use today is dominated by fossil fuels. Despite expectations that the world will shift away to newer, cleaner forms of energy—such as renewables in power generation and transportation—such a change has only been incremental up to this point. But what if governments attempted to remake their economies on a platform of clean energy? What if a paradigm change in energy production did occur? What might be the plausible events that set such a course of events in motion, and what impact would they have on the Canadian oil sands industry?

The New Social Order scenario is the most revolutionary of the three scenarios. It supposes a massive shift in the global economic system, in which leading industrial nations transform their economies from a model in which economic benefits are maximized and free markets reign to a model that emphasizes a greater degree of government direction of the economy, especially regarding sustainable development and the internalization of the social and environmental costs of fossil fuels. The Canadian oil sands are at the nexus of this shift.

The scenario does not assume that governments can engineer such a monumental change simply by fiat. Rather, it assumes that a broad societal shift occurs as a result of both the global economic crisis that began in 2008 as well as a new, more severe oil crisis in 2014 in which the vulnerability of the global economy to disruptions in oil supply is revealed as never before. There is a major societal rethink of the role of government in the economy in general and energy specifically. Alternative energy is pursued aggressively.

The New Social Order scenario has mixed implications for the Canadian oil sands. The high oil prices associated with the oil crisis provide the economic opportunity for the industry to invest and grow and meet a market need for secure supply. Early in the scenario, oil sands are viewed as an attractive investment opportunity for international oil companies that see dwindling opportunities around the world to invest and replace their reserves. At the same time, however, a regulatory shift is occurring in which much more emphasis is placed on environmental protection and sustainable development. Tightening regulations raise the cost of developing the oil sands. Perhaps more importantly, demand for petroleum enters a permanent decline in North America, as a revolution in alternative fuels, electric vehicles, and efficiency gains takes hold. In this scenario the oil sands industry has two well-defined periods: strong growth initially, followed by virtual stagnation as demand falls, oil prices decline, and environmental regulations tighten significantly.

Although oil sands production flattens out in the second half of this scenario, there are still quantifiable economic benefits that accrue to Canada and the United States. Total direct and nondirect spending related to oil sands developments grows to over C$40 billion (constant 2008 Canadian dollars) per year. By 2035 about 450,000 jobs are directly or indirectly related to the oil sands, the majority of which are long-term operations positions. New construction jobs are sustained by the move within the industry to advanced technologies for steam generation and CCS projects. Total municipal, provincial, and federal government revenues in the past ten years of New Social Order average C$8 billion (constant 2008 Canadian dollars) per year.*

The Next Oil Crisis

The economic crisis of 2008–09 is deep, but a recovery emerges in 2010 thanks to the injection of huge amounts of liquidity by national governments around the world. Nevertheless, as soon as the first crisis passes, a second one emerges, driven by yet another cyclical—and even more violent—upswing in energy prices.

As energy demand recovers from the economic crisis, it becomes evident that supply growth is insufficient to keep pace. Too many oil production projects were delayed, deferred, or shut in during the crash in oil prices that occurred in 2008–09. Oil prices begin a strong recovery, and by 2011 the benchmark light, sweet crude averages about $100 per barrel in constant 2008 US dollars ($109 in nominal terms).

Despite a rapid return to a high oil price environment in 2010, the producers' supply response initially lags. Raising the capital necessary for new projects is difficult, owing to still-sluggish credit markets. In the equity markets primary and institutional investors are hesitant to funnel capital toward the oil sands, as they are fearful that the latest run-up in oil prices will reverse as quickly as in 2008. The appetite for new oil sands investment is further limited by the emergence of alternative fuels and vehicles and increasingly aggressive government mandates intended to decrease oil demand.

*CERA estimated these economic benefits by leveraging methodology outlined in the Canadian Energy Research Institute (CERI) 2005 study *Economic Impacts of Alberta's Oil Sands.*

After oil prices remain high for several years, however, the market for investment funds begins to open up. By 2014 incremental annual capacity growth is over 100,000 barrels per day (bd). From this point production growth returns to high gear, stretching Alberta's ability to supply the required materials and labor for the multiple projects running in parallel.

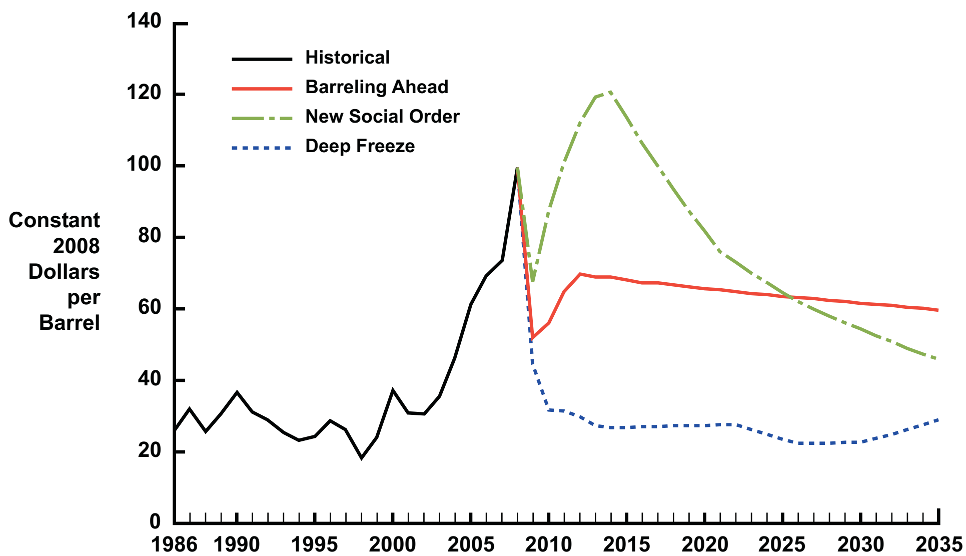
In 2014 a series of severe supply disruptions, including lengthy disruptions in West Africa and the Middle East, push oil prices even higher. The net result is that global spare oil production capacity tumbles to razor thin levels. Oil prices reach absolute levels last seen in 2008, but this time the crisis is broader and longer lasting. Prices recede only gradually over the course of several years. Benchmark light, sweet crude prices average $121 per barrel in constant 2008 US dollars ($140 per barrel in nominal terms) and do not drop below $100 in constant 2008 US dollars until nearly 2020 (see Figure IV-1).

A New Social Order Is Born

This period of continuous turmoil in the oil markets, coming on the heels of the economic crisis of 2008 and 2009, has a profound impact on government activism around the world. In both Canada and the United States citizens encourage the government to reinvent their economies on a clean energy platform. The Canadian federal government's Clean Energy Program (CEP) is initiated in 2013. The CEP reallocates some of the oil wealth from western Canada to investments in an ambitious array of zero-carbon energy technologies, such as hydroelectricity, renewable power technologies, and nuclear power. These government programs also provide strong incentives for alternative fuels and technologies in the transport sector, including biofuels and plug-in hybrid electric vehicles.

Figure IV-1

WTI Real Crude Oil Price



Source: Cambridge Energy Research Associates, Platts.
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The Canadian federal government also establishes a new industrial strategy focused on an internationally competitive infrastructure for the production and export of green technologies. Similarly, clean energy industries become a critical component of the US economy, which is seeking to remake itself out of the financial catastrophe of 2008–09. A new social order is born.

Society’s growing consideration of social and environmental issues results in increasing regulatory oversight for the oil sands industry, particularly in addressing the cumulative impacts on air quality, water quality, and land use created by oil sands development. Phase II of the Athabasca River Water Use Framework brings in a new era of radical changes in water management for the Athabasca River, including eliminating most withdrawals in the winter. Mine operators respond by storing more water on their leases. Tailings management regulations are expanded to require dewatering of tailings from past operations, and the recovered water from tailings reduces net water use and withdrawals from the Athabasca River. Reclamation of mining lands accelerates, and the inclusion of wetlands in the reclaimed landscape is mandated. In response technology for wetlands restoration improves, including progress in restoring fen bogs and peat-forming wetlands toward the end of the scenario period. All these changes result in rising costs for oil sands producers.

Aboriginal groups resort to legal recourse on conflicts between oil sands developments and their traditional uses of land as well as the maintenance of defined areas of wetlands. The government responds by setting aside 30 percent of the land in the Regional Municipality of Wood Buffalo to remain undeveloped. To preserve some lands, the Alberta government takes advantage of leases that are due to expire and in other cases forces operators to trade leased tracts for other lands.

A Climate Change Policy with Teeth

As part of their mandates to remake the economic and energy landscape, both the Canadian and US governments institute stringent regulations that require deep cuts in GHG emissions. Of the three scenarios the climate change policies adopted in New Social Order are the most aggressive.

The United States and Canada carefully negotiate a host of policies aimed at reducing GHG emissions in New Social Order. The centerpiece of these policies is an economywide cap-and-trade program—a market-based policy whereby the government sets an overall limit on the amount GHG allowed to be emitted and then private companies or individuals trade for the right to emit the pollutant. These allowances are fungible between Canadian and US market participants. The program is implemented on an aggressive timeline and starts in 2012. The new law targets a 30 percent reduction in US and Canadian GHG emissions by 2030 from 2008 levels. Allowance prices under this new carbon regime are robust and climb to $100 per metric ton in constant 2008 terms ($134 in nominal terms) by 2020.

Critically the price of carbon in this scenario is high enough to support the commercial deployment of CCS—a technology that matures as learning and scale drive its costs lower. CCS is retrofitted to existing oil sands operations, and a host of other carbon reduction opportunities become commercial after 2030 under the new carbon pricing regime—including new “small” nuclear power plants and most renewable power options. And, in contrast to the other scenarios, this cap-and-trade program applies along the entire fossil fuel value chain, from the wellhead to the tailpipe. The most important effect from the point of view of the Canadian oil sands is that this program contributes to the beginnings of the decarbonization of the transportation sector, accelerating the decrease in petroleum demand.

An important aspect of this scenario is that CCS cannot occur without substantial industry collaboration. The geological formations around the Fort McMurray region do not support carbon sequestration, and therefore the industry’s CO_2 emissions must be piped to the Edmonton area for storage. Individually, each oil sands operator cannot justify the high capital cost of a pipeline, since their emission volumes are not large enough. Therefore, in 2020 the industry and government collaborate to fund the construction of a network of gathering pipelines to aggregate CO_2 and transport them via a central pipeline to Edmonton.

A federal low-carbon fuel standard (LCFS) is also passed into law by the US government in New Social Order. This LCFS requires oil companies to reduce the GHG emissions intensity (as measured on a full life-cycle basis) of transportation fuels supplied to the market by 10 percent. Essentially, compliance can be achieved through improving the life-cycle carbon-intensity of crudes (through production efficiency gains or technology like CCS), by processing lower carbon-intensive crude oils (assuming they are available), and by increasing the blending of biofuels that have a demonstrable life-cycle reduction in GHG emissions.

Partially in response to the LCFS, Canadian oil sands producers improve the GHG intensity of producing and upgrading bitumen to SCO by one third by 2035. Primarily this is accomplished through improved efficiency and the limited adoption of CCS technology. However, the downstream oil industry complies with the LCFS primarily by blending increasing volumes of biofuels—especially imported sugar cane–based ethanol and next-generation biofuels derived from cellulosic material, both of which have low life-cycle GHG emissions. By 2020 these advanced cellulosic-based biofuels are becoming commercially available owing to technology advances, the regulatory push from the LCFS, and other government incentives. By 2035 the North American vehicle fleet increasingly comprises flex-fuel cars and light trucks, able to run on any combination of gasoline, conventional ethanol, or advanced bio-gasoline (for example, biomass-derived higher alcohols such as butanol). By 2035 biofuels make up over 20 percent (by volume) of gasoline consumption and nearly 10 percent of diesel consumption in North America. Plug-in hybrids make up nearly 25 percent of all new light duty vehicle sales by 2035.

Despite the ramp-up in biofuel blending and improved GHG intensity of oil sands production, many oil companies are unable to fully comply with the LCFS, since conventional corn starch–based ethanol, which has a less favorable life-cycle emissions profile than advanced biofuels, retains a significant share of total biofuels supply. A fuel surcharge is imposed on oil companies that are in noncompliance—most of which gets passed on to end consumers.

Both the cap-and-trade program and the LCFS lead to gasoline and diesel prices that are higher than they otherwise would be in this scenario. This is another important reason—in addition to increased fuel economy standards, biofuel blending, and plug-in electric vehicle commercialization—that North American petroleum demand declines in this scenario.

OIL SANDS DEVELOPMENT: A RAPID RISE AND THEN A SHIFT TO SUSTAINABILITY

For the Canadian oil sands the resumption of high oil prices beginning in 2010 is a green light to resume projects that were delayed during the downturn of 2008 and 2009. For several years commercial and government interest in facilitating rapid growth in the oil sands is strong given chronic supply disruptions in the greater global oil market and the worsening oil crisis.

Over the course of the New Social Order scenario, however, the oil sands face a roller coaster of shifting oil prices and rising industry costs and a sea change in oil demand trends. Ultimately, after a rapid ascent, production capacity stalls at 2.9 mbd by 2020. The most important trends in this scenario are

- **A resumption of cost inflation.** The rapid restart of oil sands investment is quickly accompanied by a resumption of shortages of labor, engineering services, and equipment.
- **The "peaking" of North American petroleum demand.** Changing consumer behavior in the face of higher fuel prices, a scaled-up alternative fuels industry, and the "electrification" of the vehicle fleet all bring about an eventual retreat in oil demand in this scenario. Global oil demand rises, led by developing economies, although significant penetration of biofuels and electric vehicles slows this arc.
- **Another steady retreat in oil prices.** The prolonged period of high oil prices in the early part of the scenario proves unsustainable in the face of weak demand for petroleum. Benchmark light, sweet crude oil prices decline steadily during the last ten years of the scenario, averaging $55 per barrel in constant 2008 US dollars ($94 in nominal terms).
- **Higher environmental and regulatory costs.** The Albertan and Canadian governments develop a wide-ranging strategy to develop the oil sands in a (more) sustainable manner. Further regulations covering land, air, water, and boreal forest issues are imposed, which significantly raise the cost of doing business in the oil sands.
- **Technology becomes the great enabler.** Declining demand and rising cost pressures are especially problematic for the oil sands as the world's marginal producers. In response oil sands technology advances rapidly in this scenario to maintain the sector's viability.

Investment Resumes, but Costs Rise

Over 1 mbd of new oil sands capacity comes online from 2010 to 2020. High oil prices and increasingly available financing encourage investment, allowing production capacity growth to ramp up from 2014 to 2020. By 2020 full-cycle steam-assisted gravity drainage (SAGD) economics require a WTI price of over $60 per barrel (constant 2008 US dollars) to cover a 10 percent return on investment, and integrated projects with a bitumen upgrader require a price over $100 per barrel.

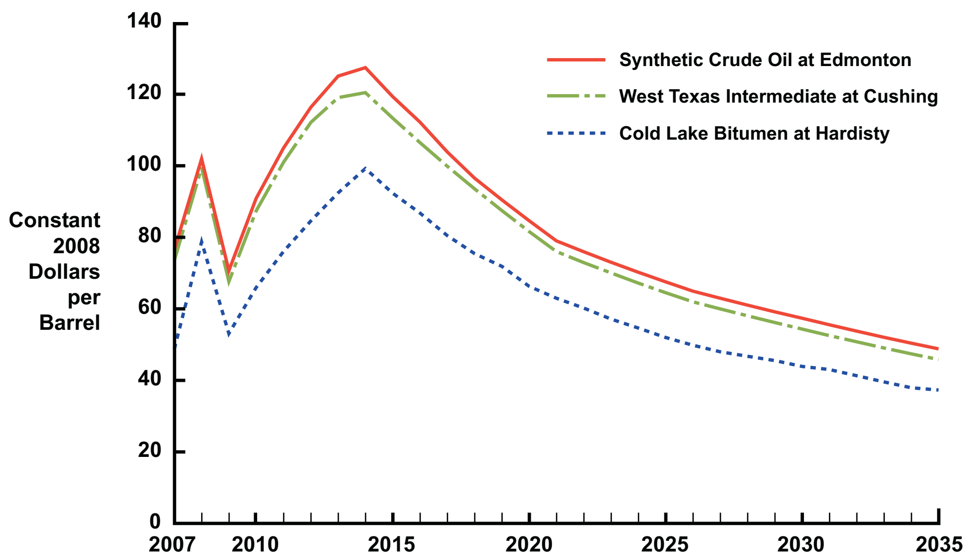
As the oil crisis escalates and benchmark light, sweet crude prices remain at elevated levels, SCO prices far outpace bitumen prices. Light, sweet crude oil prices are at a substantial premium during this period, owing to the supply disruptions of high-quality crude oils from West Africa and elsewhere in the world (see Figure IV-2).

This healthy price differential between bitumen and light crudes, which averages about 20 percent during this scenario, motivates investment in upgraders. Ultimately, between 2010 and 2020 a total of about 650,000 bd of SCO capacity comes online. There is strong demand for this product, as it yields mostly transportation fuels, which are in short supply owing to the disruption in conventional light, sweet crude imports into North America during the oil crises of the first half of this scenario. The US Midwest and Rocky Mountain states—the traditional market outlet for oil sands material—increase their imports of both SCO and diluted bitumen during this period, facilitated by the completion of new pipeline capacity in the early part of the decade. Demand for diluted bitumen from 2010 to 2020 in these two important markets increases from 380,000 bd to 880,000 bd.

With oil sands production rising rapidly, however, and refiners throughout North America eager to access this growing and politically stable source of oil, new pipelines are needed. In 2018 Line 9—a 200,000 bd pipeline that currently flows from Montreal to Sarnia—is reversed to allow shipment of SCO and synbit (a 50/50 blend of SCO and bitumen) to Quebec

Figure IV-2

New Social Order Scenario: Oil Prices



Source: Cambridge Energy Research Associates.
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refiners. In 2014 a 500,000 bd pipeline is completed, linking Alberta producers to the US Gulf Coast. The sophisticated refining hub of the US Gulf Coast proves a deep market for incremental bitumen supplies, allowing Canadian producers to fetch world prices for their products. A second pipeline is added by 2020 to accommodate the increasing volumes of oil sands products, which are needed to replace volumes in the US Gulf Coast as Venezuelan and Mexican oil production declines. In this scenario a new export pipeline to the West Coast does not materialize owing to the Canadian government's focus on sustainability and environmentalism. Shortages of diluent, which is required to ship bitumen by pipeline, are initially an impediment for the industry in this scenario. But with the completion of a pipeline from Chicago to Edmonton, producers are able to access both recycled diluent and diluent supplies all the way from Mont Belvieu, Texas.

Expansion of oil sands production capacity from 2014 to 2020 also brings an unwelcome resumption of industry cost increases. Capital costs initially drop by 10 percent from their peak in 2008 until 2010 as a result of the slowdown caused by the great recession of 2008–09. However, the slowdown in Alberta and other oil-producing regions around the world is short lived, and with benchmark light, sweet oil prices averaging close to $90 per barrel by 2015, capital costs start once again to increase as investment surges and producers begin executing projects in parallel. With growing levels of project activity in Alberta and high oil prices supporting a new surge in energy investment globally, the supply chain for materials and equipment becomes stretched. Capital costs for oil sands projects return to the steep escalation profile of the 2004 to 2008 period. Alberta's ability to supply labor is also tested, as demand exceeds labor supply by the end of 2014 and reaches 33,000 workers by 2017.

By 2020 the capital cost to build an upgrader or a SAGD facility in the Fort McMurray area is over 30 percent higher than the previous peak prices in 2008. New integrated SAGD projects with a bitumen upgrader require a WTI price over $100 per barrel to meet a 10 percent return hurdle rate—much higher than prevailing light, sweet crude prices. By the end of 2020 this capital cost escalation combined with the downward trend of oil prices renders many of the oil sands projects uneconomic. Bitumen-only projects remain economic, but producers concerned with the upward trajectory in costs and the downward trend in oil prices put new investment decisions on hold. Existing projects are completed, but new investment ceases. Despite low project activity and declining energy prices during 2025 to 2035, the global move to alternative fuels and technologies (such as gasification and carbon capture) keeps pressures on many global suppliers of equipment and engineering, preventing oil sands capital costs from falling significantly. In contrast to the Barreling Ahead scenario, industry finds less sympathy from the federal government regarding these stubborn cost pressures, since the government's mandate in this scenario is firmly to promote clean energy and sustainability, and many of the factors maintaining pressure on costs are global, not local, in nature.

Although new projects from 2025 to the end of the scenario period are not economic, existing oil sands operations are able to easily cover their operating costs. Integrated oil sands operating costs average $30 per barrel and SAGD operating costs average $21 per barrel. Carbon allowance prices, which average over $100 dollars per metric ton (constant 2008 dollars) by 2020, make up about $6 per barrel of operating costs for SAGD.

Finally, the Alberta "sliding scale" royalty regime remains unchanged in this scenario. By 2020, with integrated investments no longer economic, there is little the government can do with royalty relief to bridge the growing economic gap. Instead the government remains focused on leveraging hydrocarbon revenues to invest in alternative energy projects as part of its sustainable energy strategy.

Peak Demand in North America

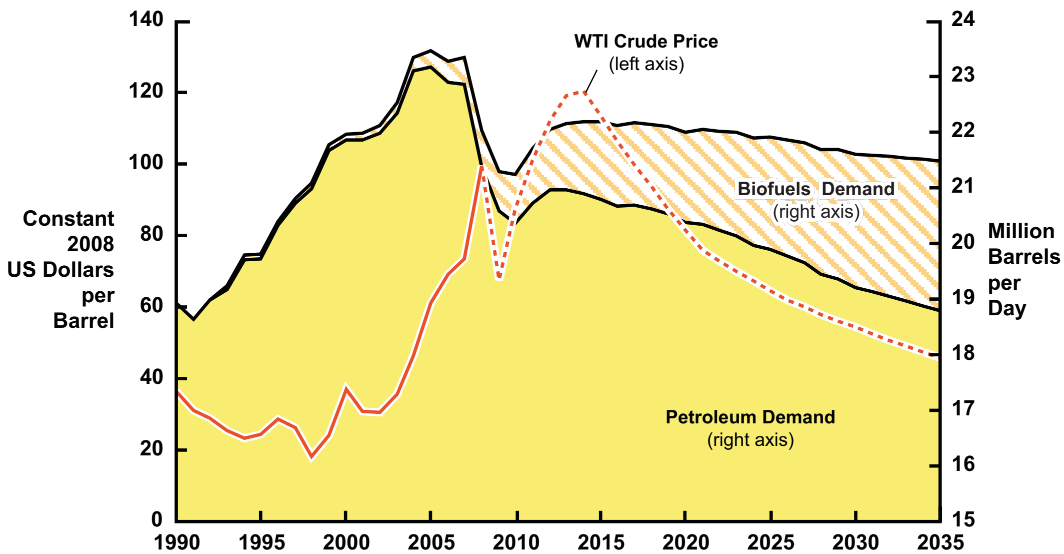
From 1986 to 2007 North American petroleum demand grew by 5.3 mbd. Growth in this market—especially for transportation fuels—was a central and dependable feature of the greater world oil market. In the New Social Order scenario the days of growth are gone. Instead North American petroleum demand enters a long, slow decline.

Peak demand occurs partly as a result of aggressive government initiatives to kick-start a scaled-up biofuels and electric vehicle industry, and partly owing to changes in consumer behavior in response to the extended period of elevated oil prices. The North American cap-and-trade regulations add about $1 per gallon (constant 2008 US dollars) to end-user gasoline prices by 2020, which keeps fuel prices high even as world crude prices begin falling.

Vehicle fleet efficiency improves substantially during 2010–20 after two decades of stagnation. Biofuel consumption increases dramatically, growing from 850,000 bd in 2010 to 2.7 mbd in 2035, owing to breakthroughs in second generation fuels made from cellulosic material and other technological advances (see Figure IV-3). Plug-in electric vehicles attain 25

Figure IV-3

New Social Order Scenario:
North American Liquid Fuel Demand and WTI Crude Price Oil Path



Source: US Energy Information Administration, Platts, Cambridge Energy Research Associates
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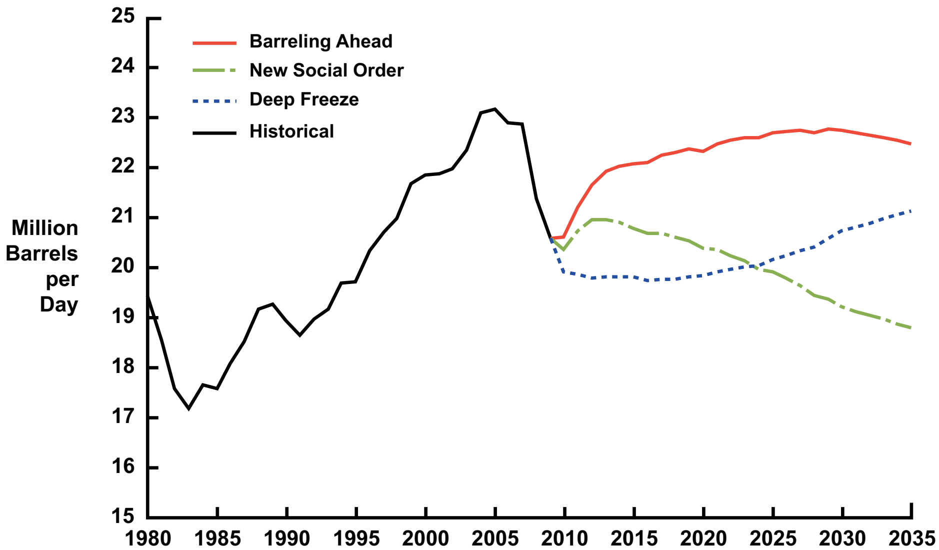
Figure IV-4

North American Petroleum Demand by Scenario



Source: Cambridge Energy Research Associates, and International Energy Agency.
Note: History and projections exclude biofuels.
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percent of new vehicle sales by 2035, further depressing demand for petroleum-based fuels. By 2020 this evaporation in petroleum demand has become a steady trend and is another signal to oil sands producers that investment needs to slow drastically. Ultimately, North American petroleum-based fuels demand declines 1.8 mbd from 2009 to 2035 (see Figure IV-4). Refineries therefore gradually decrease their capacity (and their demand for crude) to prevent overcapacity. This is especially true in the US Midwest, where demand is especially weak and new biofuels supplies are increasingly available.

World petroleum demand grows in the New Social Order scenario, although the growth is concentrated entirely in developing countries. Total liquids demand grows by 16.5 mbd from 2009 to 2035, although owing to the strong penetration of biofuels, demand for petroleum increases by only 12 mbd, or just 600,000 bd per year.

What Goes Up Must Come Down: Oil Market Cyclicality

By 2020 the oil crisis that lasted for much of the decade is a receding memory. Oil supply from the Middle East and West Africa has recovered. At the same time, however, North American demand is in terminal decline, as is demand in many other OECD countries. The result is a steady fall in oil prices. For oil sands producers the combination of a bearish market for oil prices and a stubbornly inflationary cost environment leads to a very challenging period.

Technology: The Great Enabler?

A key feature of the New Social Order scenario is the rapid development of technology. Technology not only enables the scale-up of alternatives to petroleum such as biofuels and electric vehicles, it also enables the oil sands to reduce its environmental footprint. Technology development in the oil sands sector is driven by two factors: the need to reduce the costs of extracting and upgrading the bitumen resource and the need for a smaller environmental footprint. But this transition is not cheap, fast, or easy. And while the oil sands improve their environmental position owing to this contribution of new technology, bitumen and SCO still have greater GHG footprints compared with many other crude oils. The same technology that ameliorates the environmental footprint of the oil sands is also at the same time improving the footprint of other crude oils and fossil fuel energy sources such as coal.

In New Social Order new, cleaner extractive technologies become commercial. SAGD techniques in combination with light hydrocarbon solvents, which are more energy efficient and use far less water, are developed. In-situ combustion technology is also developed, reducing the need for steam and allowing a high proportion of the CO_2 to remain sequestered in the formation. Even small nuclear facilities are being used by 2035 to provide steam for SAGD facilities. By 2035 approximately 10 percent of the oil sands total capacity is powered by gasifiers, nuclear generators, or nonsteam technologies, such as in-situ combustion techniques. And by 2035 nearly a quarter of upgraders have been retrofitted with advanced, low-cost gasifiers, all using CCS technology to capture CO_2.

As a result of vastly improved steam-oil ratios (SORs), CCS, and other advanced technologies, the GHG intensity of oil sands production improves by over 30 percent between 2008 and 2035 in New Social Order. Although this improvement in emissions intensity is impressive, aggregate emissions from the sector still increase, owing to the significant increase in oil sands production which overwhelms the per-barrel improvements in GHG intensity. By 2035 GHG emissions in New Social Order increase to 65 million metric tons (mt), from about 40 mt in 2008.

In the mining projects technology leads to major advances in tailings and water management. Regulations require industry to develop an effective reclamation process to convert fluid fine tailings, including legacy tailings produced by past operations, to use for trafficable areas. As companies work to comply with these new regulations, they implement a variety of technologies. Existing tailings are consolidated via the addition of gypsum and other substances. Significant progress in the commercialization of centrifuging technologies allows new and old tailings to be consolidated efficiently and cost-effectively. Since old tailings are remediated in this scenario, end pit lakes (EPLs) are ultimately not required in the reclaimed landscape. These advances reduce the volume of water needed to produce a barrel of bitumen from 4 barrels of water to less than 3 barrels. By 2020 large tracts of tailings are trafficable, the volume of tailings ponds necessary to contain waste decreases drastically, and the pace of reclamation accelerates. This, in turn, reaps large benefits in public opinion of the oil sands, since tailing ponds are the most visible evidence of the oil sand's environmental cost.

BARRELING AHEAD SCENARIO: KEY INSIGHTS

Insight 1. Aggressive expansion of oil sands production could play a major role in boosting world oil supply and strengthening North American oil security, especially in a scenario of rapid oil demand growth worldwide. However, such an expansion would also require substantial increased use of natural gas, resulting in higher gas prices and increasing imports of liquefied natural gas to the United States unless a new pipeline comes into service delivering gas from Alaska to the US lower-48 states. In the absence of gas deliveries from Alaska, the United States would become more reliant on non-Canadian gas imports, since the oil sands would consume a large part of Canadian gas supply.

Insight 2. The Canadian oil sands could become a significant source of long-term job and revenue growth for the Canadian economy. Economic benefits could also accrue outside of Canada, as pipeline and refinery retrofits would be needed in the United States to process oil sands material.

Insight 3. A substantial increase in Canadian GHG emissions by 2035 is an unavoidable by-product of an aggressive growth path for oil sands unless there is a dramatic improvement in technology. However, it is unclear whether GHG emissions would be substantially different in the absence of oil sands development, since the majority of the liquid fuel needed to meet demand would need to come from another source of crude. The GHG impact of this substitution would depend entirely on the future quality of the liquid fuel replacing the oil sands, which is uncertain.

Insight 4. The oil sands could consume a huge proportion of Canadian natural gas production. In the Barreling Ahead scenario oil sands production reaches 6.3 mbd in 2035—up from 1.3 mbd in 2008. To produce this volume, oil sands facilities, in aggregate, consume 6.3 billion cubic feet (Bcf) per day of gas—40 percent of total 2035 Canadian gas demand.

Insight 5. Progress in addressing the cumulative effects of land disturbance, water management, tailings accumulation, and other environmental issues could be very challenging to manage in a scenario of the most rapid oil sands development.

Insight 6. To reach 6.3 mbd of production in Barreling Ahead, technology or water management practices must advance to minimize consumption of fresh water from the Athabasca River. A key uncertainty is whether groundwater resources could support a large ramp-up in in-situ thermal production capacity.

Insight 7. Strong and steady growth in the oil sands is possible only if innovations in cost control and project execution are introduced, such as the offshore fabrication and importation of large equipment modules, which could decrease both cost and regional labor requirements.

Insight 8. Favorable government policy could play a critical role in an aggressive expansion of oil sands production, including proactive support to access new markets, to decrease logistical barriers to execute projects, and to gain the support of First Nations groups.

Insight 9. Rapid growth in the oil sands will require access to world markets and world prices. Pipeline capacity expansion to the sophisticated refineries at the US Gulf Coast will be required to support such growth, and waterborne access to Asia and the US West Coast is likely to be needed as well.

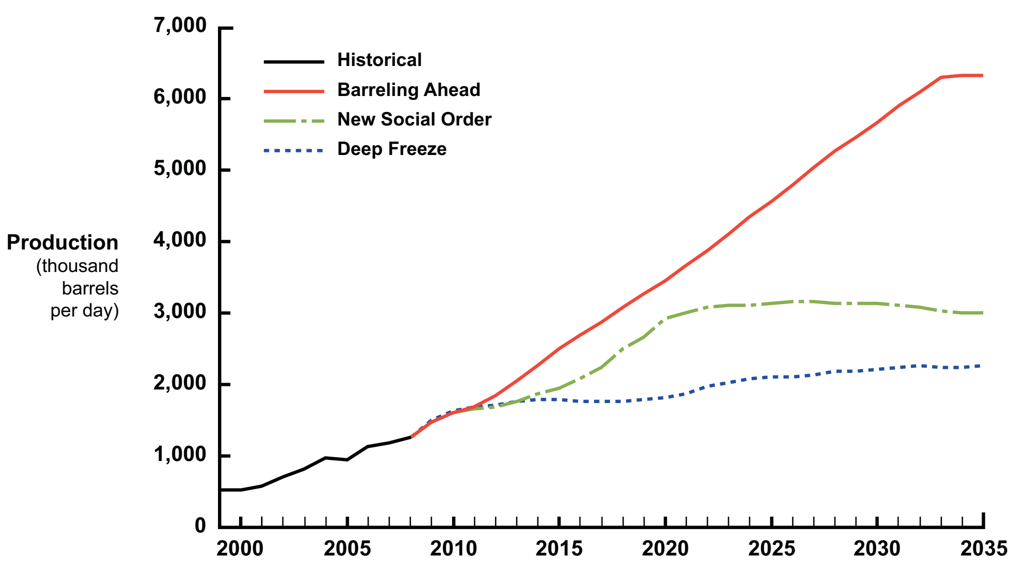
HOW FAST, HOW BIG—AND AT WHAT COST? THE ECONOMIC AND ENERGY CONTEXT OF BARRELING AHEAD

How fast could the production of Canadian oil sands grow? What would it take to make Canada one of the biggest producers of petroleum in the world? What would be the environmental and social costs and benefits of such aggressive expansion?

These are the questions the Barreling Ahead scenario seeks to answer. In this scenario the Canadian government plays a strong role to facilitate and maximize the development of Canada's vast energy storehouse. Oil sands production reaches 6.3 mbd in 2035 (61 percent SCO and 39 percent bitumen by 2035)—a 400 percent increase from 2008 (see Figure IV-5). Total Canadian crude production tops 7 mbd in 2035, placing Canada among the world's top oil producers. But this scenario also features a substantial increase in GHG emissions from oil sands facilities. Oil sands GHG emissions rise from 40 mt in 2008 to nearly 170 mt in 2035 (see Figure IV-6). Management of water and mine waste are two other key environmental issues associated with oil sands development that are particularly challenging in this scenario. Rapid oil sands development also creates the potential for conflict with Canada's Aboriginal population.

Figure IV-5

Oil Sands Production



Source: Cambridge Energy Research Associates.
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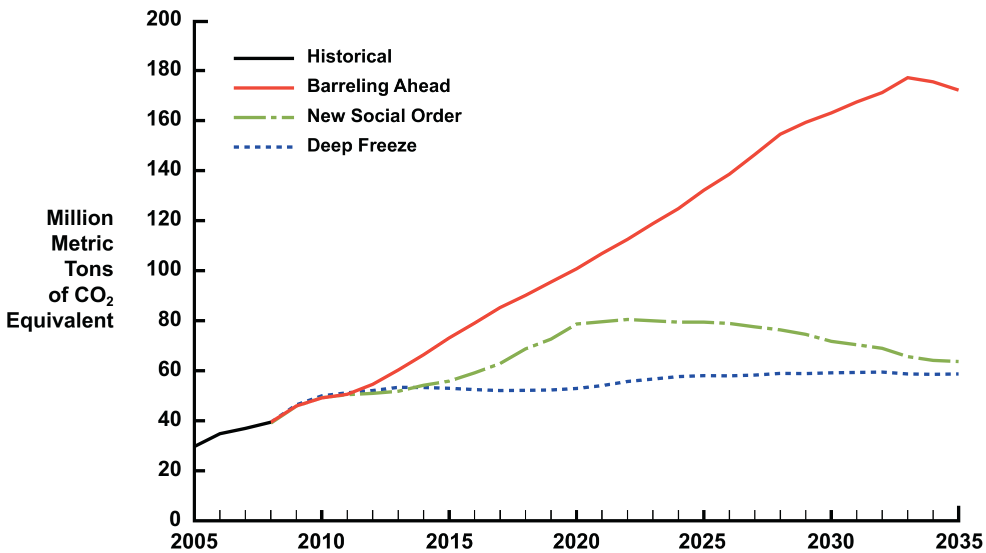
Figure IV-6

Greenhouse Gas Emissions from Canadian Oil Sands Production



Source: Cambridge Energy Research Associates.
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Strong oil demand—especially in Asia—and high prices are the defining global characteristics of Barreling Ahead. Oil prices remain high enough to support continuous oil sands investment in both integrated and upstream only projects. This scenario also demands much of new technologies, both to facilitate oil sands growth and to mitigate its environmental footprint.

Economic Recovery and the Resumption of Growth

The starting point for Barreling Ahead—as with all the scenarios—is the "great recession" that began in the United States in 2007 and spread throughout the world in 2008 and 2009. The economic contraction is painful and deep, but mercifully shorter than many expect. The "great recovery" begins in 2010. China, whose economy avoids the steep contraction seen in the United States, is a major engine of the recovery. Another factor that spawns recovery is the impact of trillions of dollars of government spending worldwide, which provides the necessary catalyst to reverse the contraction in global gross domestic product (GDP). In addition to China, other Asian economies, such India and Vietnam, resume a very strong path of economic expansion. India's service industry finds a large new client base in the expanding multinational companies based in China. Of the three scenarios, Barreling Ahead assumes the strongest economic growth during 2010–35, both at the global level and in North America. Global GDP growth averages 4.2 percent per year from 2010 to 2035, while North American GDP growth averages 2.5 percent.

The oil sands themselves are an important contributor to economic growth in North America in the Barreling Ahead scenario. Total direct and indirect spending related to oil sands development grows to over C$90 billion (constant 2008 Canadian dollars) per year. Over 750,000 jobs are created, directly and indirectly, as a result of oil sands development, of which 80 percent are long-term operations jobs. By the last ten years of the scenario Canadian government revenue (municipal, provincial, and federal) grows to C$18 billion per year (constant 2008 Canadian dollars)—nearly four times 2008 levels.*

The First Prerequisite for Oil Sands Recovery: A Rebound in Oil Demand and Oil Prices

Economic recovery from the great recession of 2008–09 is the first step in the resurgence of commodity prices from the multiyear lows reached in 2009. Oil prices in particular prove resilient, especially as world oil demand returns with a vengeance after the two-year contraction of 2008–09. The benchmark light, sweet crude oil price moves to $56 per barrel in constant 2008 US dollars ($59 in nominal terms) in 2010, drifting up to $68 per barrel in constant 2008 US dollars ($81 in nominal terms) by 2015 before flattening out for much of the rest of the scenario period. In this scenario a relatively tight supply-demand balance for oil reemerges, although prices are at more moderate levels than during the peak in 2008. In other words, in Barreling Ahead oil prices settle into a new equilibrium level that is structurally much higher than pre-2000 levels.

Despite a return to prosperity, the world remains vulnerable to shocks—from trade disputes, security concerns, regional conflicts, and changing geopolitics. As a result, energy security remains high on the agenda of great powers in this scenario—especially in the United States and China, the world's two biggest oil importers. Periodic conflicts and a tight oil supply-demand balance lead energy consuming nations to focus on supply security and diversification. In this context Canada is an attractive and stable environment in which to procure long-term oil supplies—not only for the United States but also for other oil-hungry countries outside of North America.

The Rise of Asia and the Emergence of a Multipolar World

Indeed, the economic crisis of 2008–09 and the resulting sharp drop in oil demand in the United States highlight for Canada the risk of a highly dependent trade relationship with its huge southern neighbor. Concern about long-term demand for oil in the United States fosters debate about the need to diversify markets as the oil sands develop.

In the Barreling Ahead scenario Canada takes advantage of the emerging multipolar world in which Asia increasingly exerts influence in world economic and political affairs. Canada pushes hard to expand trade with India and China. These energy-hungry nations in turn see the Canadian oil sands as a means of obtaining secure energy supplies and diversifying energy sources and seek active participation as producers. Canada sees major advantages in market diversification, especially given the large volumes of oil sands production in this scenario.

*CERA estimated these economic benefits by leveraging methodology outlined in the CERI 2005 study *Economic Impacts of Alberta's Oil Sands.*

THE PATH TO 6.3 MILLION BARRELS PER DAY: NEW MARKETS, NEW TECHNOLOGIES, AND NEW ECONOMIC PARADIGMS

By 2035 Canada's oil sands are producing 6.3 mbd of bitumen and SCO—a nearly fivefold increase in production from today's levels. Growth is sustained at a strong and steady pace and averages 180,000 bd of new capacity each year though to 2035.

What are the economic and technological trends that enable industry to achieve this robust level of production? There are several keys to such a growth path:

- **Robust oil prices.** Benchmark light, sweet crude prices average $64 per barrel in constant 2008 US dollars ($91 in nominal terms) during 2009–35 in this scenario, providing an adequate return on investment for both bitumen producers and upgraders.

- **Healthy oil demand.** World oil demand recovers, first in Asia and then in North America. Relatively strong growth is sustained on the back of consistently strong economic growth. World liquids demand increases nearly 30 mbd from 2009 to 2035, propelled by average world GDP growth of 4.2 percent per year.

- **Moderating project costs.** Industry costs decline sharply from the 2008 peak, and subsequent cost increases are incremental; no major, long-lived cost spikes occur.

- **Technological solutions.** Necessity is the mother of invention in this scenario. Key technological breakthroughs keep a growing industry's costs in line. This allows the industry to reduce the intensity of natural gas use per barrel of output, although the magnitude of the overall increase in capacity leads to substantially higher consumption of natural gas.

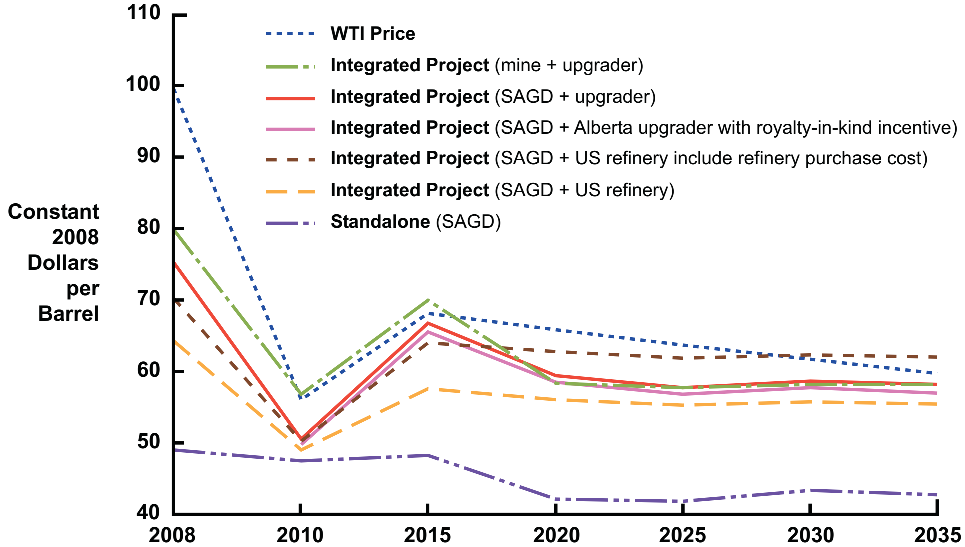
Improved Project Economics and Stronger Demand

Over the course of the Barreling Ahead scenario in-situ SAGD projects require a WTI price ranging from $40 per barrel to $50 per barrel in constant 2008 US dollars to cover a full-cycle production cost including a 10 percent return on investment. These projects are supported by relatively high prevailing prices for light, sweet crudes in this scenario. Integrated projects with a bitumen upgrader require a WTI price ranging from $50 to $75 per barrel.

Light-heavy crude price differentials gradually narrow throughout the scenario. While Alberta upgrading economics are marginal only for a few relatively short periods during the scenario, the narrower differentials provide a higher return to bitumen producers (see Figure IV-7). Despite these favorable economics for bitumen producers, the bitumen-only strategy is not without risk. Bitumen producers still must ensure that they have an end market for their product, which is not fungible in most refineries. Therefore, bitumen producers continue to seek partnerships with existing refineries in the United States capable of processing bitumen, or purchase refineries which they retool to process bitumen.

Figure IV-7

Barreling Ahead Scenario: Breakeven WTI Prices



Source: Cambridge Energy Research Associates.
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The Alberta government is concerned by the potential loss of value-added upgrading to the Alberta economy caused by a reliance on bitumen production instead of upgrading. In 2013 the government begins to roll out its bitumen-royalty-in-kind program (BRIK), which requires producers to pay royalties in physical barrels of bitumen instead of cash. This in turn allows the government to deliver its BRIK barrels to negotiated projects (such as upgraders) and to sell its noncommitted volumes into other markets. To help foster upgrading in Alberta, the government sells BRIK barrels to Alberta-based upgraders at US$2 per barrel below the market price of bitumen, effectively widening the light-heavy price differential. This provides some economic incentive for producers without existing refinery outlets for their bitumen, and in conjunction with moderating capital costs, a strong oil price level, and the rapidly growing need for a flexible crude supply in Asia, leads to healthy investments in upgrading projects in the province.

Throughout the scenario the Alberta government tweaks the royalty regime for oil sands, including some increases for bitumen-only producers with a higher rate of return. However, these tweaks do not materially change the guiding principles of charging lower royalties prior to payout and using rates that change with the WTI price.

Bitumen producers enjoy relatively strong prices for their product during the first decade of the scenario. Not only does the rise in the benchmark light, sweet crude oil price lift all boats, but the supply of heavy crude relative to light crude around the world tightens slightly. Heavy crude prices are less deeply discounted to light crude as a result. Bitumen prices average approximately 80 percent of the WTI price from 2010 to 2020, a significant improvement from the 70 percent level seen during 2005–08.

Favorable Conditions for Increasing Market Access

To support an aggressive ramp-up in production, downstream markets need to be developed and logistical links to these markets must be built. By 2012 approximately 1.3 mbd of expanded pipeline capacity from Alberta to the US Midwest is completed.*

During 2010–20 several refineries in the US Midwest complete expensive overhauls to allow their facilities to process diluted bitumen. At the same time, overall demand for oil is rebounding from the deep decline of 2008–09. From 2010 to 2020 North American demand increases by nearly 2 mbd. During this period, total imports of diluted bitumen into the US Rocky Mountain and Midwest regions (traditional markets for oil sands products) grow by almost 850,000 bd. The US market for SCO also expands during this period, especially as local availability of light, sweet crude declines.

As the US Rocky Mountain and Midwest markets become saturated, however, new outlets for oil sands material are required. Beginning in 2014 bitumen prices find significant support owing to the completion of a large new 500,000 bd pipeline, followed by another 450,000 bd pipeline in 2020, which allow diluted bitumen to flow from Alberta all the way to the huge, sophisticated refining nexus of the US Gulf Coast. With this critical link established, bitumen producers in Canada are finally able to fetch the same world price for heavy crude as other producers that sell into the US Gulf Coast, such as Mexico and Venezuela. In 2018 SCO and synbit producers access new markets on the East Coast with the reversal of Line 9, a pipeline that currently flows from Montreal to Sarnia. This reversal allows significant shipments of oil from Alberta to Quebec.

This link to world markets is further solidified by the expansion and addition of new pipeline capacity to the West Coast. Existing pipeline capacity linking Alberta with the Greater Vancouver area is expanded by nearly 400,000 bd by 2015, and by 2023 another pipeline is added, a 525,000 bd pipeline linking oil sands producers with the deepwater port of Kitimat, British Columbia. Before they can proceed, these projects require careful negotiations between the provincial government, the oil companies, and the First Nations who live along the pipeline corridor, who are initially opposed to further disturbance of their lands and hunting grounds. Ultimately, the First Nations leadership and industry enter into a partnership agreement in which the First Nations groups are granted an equity stake in the pipeline. This collaborative effort is seen as a way to improve the long-term economic development of the First Nations communities.

Critically, the new west coast pipeline is built only with the strong support of the Canadian federal government, which is driven by its mandate of a strong energy policy and strategic goal of diversifying the country's energy export markets. The federal government plays an important role in working with local community stakeholders to get the necessary approvals for the project, such as allowing supertankers access to Kitimat.

*Three pipeline projects—Enbridge's Southern Access line, its Alberta Clipper project, and TransCanada's Keystone line—are currently under construction and assumed to be operational by 2012.

The Diluent Challenge

Bitumen cannot be transported by pipeline without diluent, and adequate diluent availability is a recurring challenge in the Barreling Ahead scenario. Diluent prices are strong early in the scenario as bitumen producers require increasing volumes of diluent to pipe their product to new customers in the United States. To alleviate this stress, a 180,000 bd pipeline from Chicago to Edmonton is completed by 2013, allowing recycled diluent (along with significant volumes of diluent brought up from Mont Belvieu, Texas) to be shipped to Alberta producers. By 2023, as demand for diluent begins to push up against the capacity of this first pipeline, a second diluent pipeline is completed, this time flowing from Kitimat, British Columbia, to Alberta. This pipeline allows supertankers loaded with diluent from distant Asian markets to ship their product to oil sands producers in Alberta. These supertankers are then able to backhaul bitumen and SCO to refineries in Asia.

Diversified Markets and US Energy Security

With the West Coast link completed, diluted bitumen or SCO can now be loaded onto supertankers to reach the oil-hungry and rapidly developing markets of Asia as well as to US West Coast refineries, which are in need of new supplies as Alaskan North Slope and California heavy crude production declines. This export pipeline link to Canada's west coast is a key victory for the government of Canada in its quest to diversify its energy market outlets. It is also a major benefit for oil sands producers, as their products are now able to fetch world market prices, instead of being price disadvantaged by their "landlocked" position. Total world liquids demand grows by nearly 30 mbd from 2009–35 in this scenario, with the majority of the growth occurring in China, India, and other rapidly developing Asian nations.

Despite this important diversification to markets outside of North America, the oil sands become a cornerstone of US energy security in Barreling Ahead. As US domestic crude production and Mexican and Venezuelan crude production declines, the oil sands' share of total US crude imports rises from approximately 7 percent in 2008 to nearly 40 percent by 2035.

The Quest to Contain Industry Costs

Spiraling capital costs were a key limiting factor to oil sands development prior to the crash in 2009. Double-digit industry inflation was the norm during 2005–08. The breakeven price for upgraders drifted steadily upward, and cost overruns and project delays were endemic. In the Barreling Ahead scenario these cost pressures do not disappear. However, they do moderate once innovative solutions are found.

Initially the average capital cost of new oil sands projects declines over 20 percent from the 2008 peak to 2010 owing to the deep world recession and the associated pullback of oil sands projects, the depreciation of the Canadian dollar, decreases in Alberta labor costs, and increases in labor productivity. Falling prices for key commodities such as steel and copper—a reflection of the global economic recession—also contribute to lower costs.

Once activity kicks back into high gear, however, costs spike again as demand for labor revives and the strong global economy feeds into much higher costs for equipment, steel, and cement. By 2015 the cost to build new oil sands projects is fast approaching the 2008 peak pricing levels in real terms. Over 33,000 mobile construction workers are back in Alberta—nearing the peak seen during 2007–08.

The oil industry, the Alberta government, and the federal government all recognize that the labor, equipment, and engineering shortage of 2005–08 must be avoided if the industry is to grow. This time they craft a proactive and collaborative plan to address industry bottlenecks, including investment in major labor retraining programs.

Workers are recruited from across Canada and around the globe; incentives are provided to encourage expansion in equipment manufacturing and module fabrication capabilities in the province and throughout Canada. The oil sands industry taps the significant capacity for both engineering design and equipment manufacture in Asia. Gradually, Asia supplies an increasingly significant share of industry capacity.

The key breakthrough in cost management comes by the end of 2016, when producers successfully deliver large equipment modules into the oil sands region from the Beaufort Sea and down the Mackenzie River to Lake Athabasca. The plan, which was advanced in both planning and feasibility stages in the 2008–10 boom, is fast-tracked by industry with strong support of the federal government, which pushes for efficient passage of the necessary regulatory assessments and approvals. This novel logistical innovation—dubbed "The Longest Module" by the industry-government consortium—removes a major bottleneck in project execution by allowing large and complex equipment modules to be built in fabrication centers outside of Alberta, significantly reducing the labor and fabrication requirements within Alberta. Capital costs and labor requirements associated with construction in the Athabasca region are reduced substantially, providing further impetus to continued growth in the oil sands sector throughout the scenario.

Using this northern route to move oil sands equipment modules also creates economic and social opportunities for First Nations groups in the Fort Chipewyan region. As with the pipeline project to the West Coast, these Aboriginal communities become equity partners with the module transportation industry. This new module-moving business creates long-term jobs in the community. An additional benefit to this community includes the construction of an all-weather road from the previously isolated region to Fort McMurray.

One trade-off of this logistical innovation in module production is the offshoring of many jobs from Alberta and Canada. However, ultimately it creates a more sustainable economic development path for both industry and the Fort McMurray region, keeping labor demand within the available supply in Alberta and decreasing the need for out-of-province and out-of-country workers that led to significant cost escalation and labor productivity issues during the mid-2000s boom.

Throughout the scenario operating costs of oil sands projects remain well below the price of crude oil, allowing project economics to remain healthy. Thermal project operating costs average $25 per barrel (constant 2008 US dollars) by the end of the scenario and under $30 per barrel for integrated mines and upgraders.

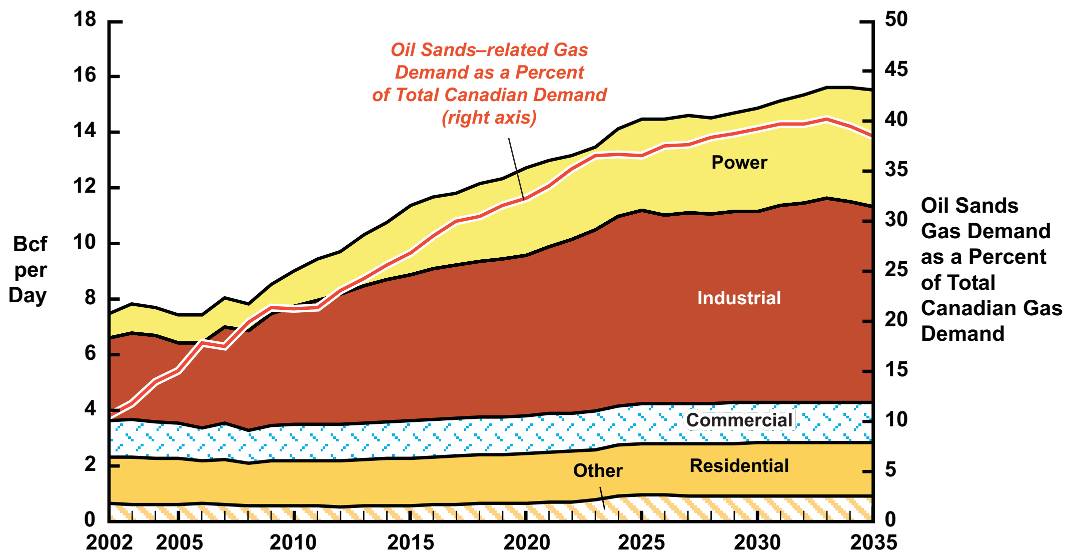
The Gas Constraint and the Need for Alternatives

Natural gas consumption soars in the Barreling Ahead scenario. Efforts to secure gas supply and to minimize its use loom larger with each passing year. Mining operations, upgraders, and in-situ facilities, which use gas to generate steam, produce hydrogen, and power their sites, consume 6.3 Bcf per day at their peak in 2033. At this volume gas demand in the oil sands sector reaches nearly 40 percent of total gas demand in Canada (see Figure IV-8). When gas prices spike, this creates tension between eastern and western Canadian politicians. In the east much is made of the higher cost to heat homes because of the "great sucking sound" of gas use in the oil sands.

New gas supplies from the Mackenzie Delta in 2020 followed by Alaskan North Slope gas in 2023 are critical to meeting the increasing needs of the oil sands. The incremental volume from these new sources—6.5 Bcf per day—is approximately equal to the total volumes required by the oil sands at their peak. Annual average Alberta hub gas prices rise from $4.50 per MMBtu (constant 2008 US dollars) in 2010 to nearly $12 per MMBtu by 2035 owing to this persistent demand-side growth.

Figure IV-8

**Barreling Ahead Scenario:
Canada Total Annual Natural Gas Demand**



Source: Cambridge Energy Research Associates, Statistics Canada.
90107-15_1404

Throughout the period other ideas for steam generation are investigated, but none prove economical compared to natural gas, and gas consumption continues to grow as a result. Despite these new flows of gas from the north, by the second decade of the scenario the handwriting is on the wall for the industry. Rising gas prices are eating into industry margins. The Canadian government has become increasingly alarmed at the rate of gas consumption and, in an effort to moderate this trend, applies a heavy tax to the price of natural gas consumed by oil sands operators. It becomes clear that further growth will depend on the adoption of new technologies to move the oil sands off natural gas. By 2025 new upgrader facilities, which traditionally run on natural gas, switch to gasification of either petroleum coke (a by-product of the upgrading process) or asphaltenes. At the same time new in-situ projects switch to using excess syngas and steam, produced from the upgrading facilities, to offset their natural gas consumption. Not all in-situ operators can economically obtain excess syngas and steam, however. For example, in-situ operators separated from upgraders by long distances instead generate steam by combusting the heaviest fraction of the bitumen they produce. These “bottom of the barrel” bitumen fractions are obtained via on-site simple distillation units and partial field upgrading units. One of the trade-offs to moving away from natural gas toward alternative steam generation technologies such as gasification and burning the bitumen bottoms is an increase in the carbon intensity of these oil sands projects.*

Technologies that do not require steam, such as in-situ combustion techniques, are also introduced commercially at this time. By 2035, 10 percent of all in-situ output is predicated on either gasification or in-situ combustion technologies. Even with the relatively high natural gas prices and a decrease in gasification costs resulting from two decades of technical innovations, the economics of switching to gasification still work only with the imposition of a tax on natural gas by the government and strong incentives such as accelerated depreciation and capital tax credits. This tax structure ensures that industry makes the switch for new projects—although the economics to retrofit existing investments is not supported.

THE ENVIRONMENT: RAPID GROWTH LEADS TO ENVIRONMENTAL CHALLENGES

An aggressive scale-up of the oil sands imposes substantial burdens on the environment. Advances in technology mitigate the impact, but do not prevent GHG emissions from rising sharply. Rapid oil sands development also creates intense local environmental and social pressures. While economic growth is the primary driving factor in this scenario, operators also need to address the cumulative impacts of rapid oil sands development. For this reason, in 2011 industry and government form the Research and Innovation Network (RAIN) for the oil sands, a collaborative research and development (R&D) center intended to address many of the long-term environmental issues surrounding the oil sands. RAIN is intended to ensure that adequate budgeting for R&D is sustained throughout the inevitable boom-and-bust oil price cycles, and is a key catalyst for some of the technological innovation in the scenario.

*The GHG emissions associated with gasification and combusting bitumen bottoms can be more than twice that of natural gas use because the carbon content of petroleum coke is twice as high as natural gas, and the efficiency of gasification is lower than for natural gas combustion.

Weak Effort to Contain Carbon Emissions

In this scenario of high global economic growth, emissions worldwide grow substantially, and hence most countries do not achieve targeted emissions reductions that are currently being discussed as part of the successor treaty to the Kyoto Protocol. Climate change remains an important issue in both Canada and the United States throughout the Barreling Ahead scenario. However, with the great recession of 2008 and 2009 still a painful memory, policymakers are wary of imposing huge new costs on a fragile North American economy in the midst of a rebound. As a result a "middle of the road" approach is adopted. A federal CO_2 cap-and-trade program in both the United States and Canada is agreed upon in 2010 and implemented in 2015. But this program only covers parts of the North American energy market. The point of regulation closely mirrors the EU Emissions Trading Scheme in that it only regulates power plants and large industrial emitters (including bitumen upgraders). In a move that helps to limit the cost of implementation, CO_2 allowance prices are actively managed through a safety valve—a price cap that prevents allowance prices from surpassing $35 per metric ton (real 2008 US dollars).

CO_2 allowance prices at these levels are not high enough to support the economics of CCS. Even with strong government incentives, oil sands operators in the Fort McMurray region do not pursue CCS in this scenario. The economics of carbon capture do not make sense at these carbon price levels, and Fort McMurray does not have the geological formations to support sequestration. The CO_2 must be transported to the Edmonton area (which has geological formations more appropriate for carbon storage), which only worsens the economics. In this scenario CCS is limited to the Edmonton area, where coal-fired power generation and hydrogen plant capacity in "Upgrader Alley" allow carbon to be captured relatively efficiently. Despite the higher emissions at some sites that generate steam by combusting bitumen bottoms or syngas, by 2035 the emissions from the oil sands start to decline as lower SORs combined with a move to in-situ combustion technologies start to reduce total emissions.

GHG Emissions Jump

GHG emissions from oil sands facilities increase from 40 mt in 2008 to more than 170 mt in 2035.* This more than fourfold increase occurs despite some gains on the emissions front; the GHG intensity of each barrel of oil sands production improves by 10 percent between 2008 and 2035, driven primarily by the benefits of better SORs. Greater overall improvement in GHG emissions intensity is hampered by the move away from natural gas consumption to the more carbon-intensive process of gasification of petroleum coke and asphaltenes. GHG emissions from oil sands production represent approximately 20 percent of total Canadian GHG emissions in 2035 (an increase from about 5 percent in 2008).

Although substantial on their own, GHG emissions from the oil sands facilities represent about 2 percent of total North American emissions by 2035 and less than 0.5 percent of total world GHG emissions (see Figure IV-9). It is also unclear whether the arc of GHG emissions would be substantially different in the absence of oil sands development. Since

*This includes the emissions associated with production and upgrading but does not include refining or consumption of the final refined products.

a central premise of this scenario is strong world oil demand growth, if the oil sands were not developed the majority of the liquid fuel needed to meet this demand would need to come from another source. The GHG impact of this substitution would depend entirely on the future quality of the liquid fuel replacing the oil sands, which is uncertain.*

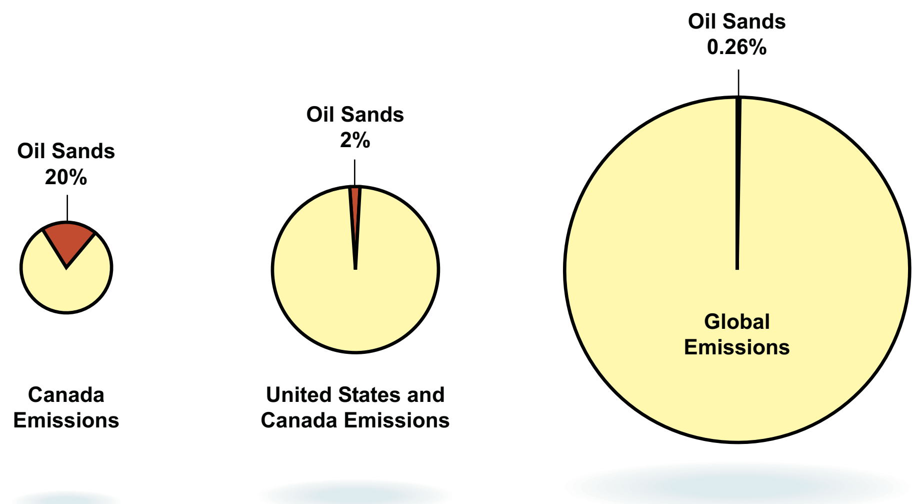
The Struggle to Address Local Environmental and Social Impacts

Water management is a critical component of the Barreling Ahead scenario. Mining operations, which depend on water from the Athabasca River, make up half of total oil sands operations by 2035. Combining current water licenses, applications for projects under review, and estimates of future project allocations results in nearly 860 million cubic meters of water per year allocated from the river by 2035, nearly a threefold increase from current levels.

Figure IV-9

Barreling Ahead: 2035 Oil Sands Greenhouse Gas Emissions

In 2035 for the Barreling Ahead scenario, GHG emissions from Canadian oil sands production reach approximately 170 million metric tons.*



Source: Cambridge Energy Research Associates.
*Considering facility-level GHG emissions for production and upgrading in Alberta.
90107-21

*As light, sweet crude availability around the world declines over time, heavier crude resources (which generally require more energy to extract and process) will increasingly be developed and gain a larger share of the world's primary energy production. However, production of natural gas liquids and condensates (which are very light and are less energy intensive from a life-cycle perspective) will also likely increase as global natural gas development grows. Both of these liquids—heavy and light—could be substitutes for the oil sands.

Given the limitations on water availability from the Athabasca River during the low-flow winter months, oil sands operators will not be able to draw their full water allocation from the river during the winter. Advancements in water management must be made.

Phase II of the Athabasca River Water Management Framework is released in 2010, further reducing allowed withdrawals from the river during the winter. Industry struggles to meet its water needs under this new paradigm, because storing the vast quantities of water needed would require them to store water on large portions of their leases instead of extracting bitumen from them. The negotiated solution is the development of an upstream dam on the Athabasca River that evens out seasonal river flows, eliminating winter withdrawal restrictions. The dam also generates electricity and GHG offsets from hydropower generation, although the trade-off is the creation of other environmental concerns typically associated with dams.

Additionally, Alberta's Energy Resources Conservation Board has issued mandatory directives for industry to develop an effective reclamation process to convert fluid fine tailings to trafficable areas. Some of the process water trapped in the fluid fine tailings is recycled, reducing the need to draw water from the Athabasca River. Over the course of this scenario this dewatering advance slightly reduces the overall volume of water used per barrel of bitumen produced from about 4 barrels of water to 3 barrels.*

However, tailings management and site reclamation prove challenging in this scenario given the rapid pace of development. Operators struggle to meet the tailing directive's requirement to eliminate the accumulation of fluid fine tailings. Additionally, no regulation requires the treatment of legacy tailings—those produced over past years of mining. Industry relies on EPLs to incorporate this waste into the reclaimed landscape. These lakes become an environmental question mark, with doubts that they can ever evolve into ecologically productive water bodies. The first full-scale EPL is in place by 2015, but at least a decade passes while operators learn how to make EPLs as ecologically productive as possible. Land reclamation also begins to progress by 2015, but the pace of reclamation does not keep up with the pace of land disturbance from new mining projects in this scenario. In addition fragmentation of the forest due to infrastructure development for in-situ projects results in a reduction of local biodiversity.

In-situ developments continue apace, resulting in some water use challenges. In-situ developments are less water constrained than mining operations because they often use brackish water from deep aquifers for steam generation, and not the Athabasca River. However, capacity growth of in-situ oil sands operations in Barreling Ahead more than triples water use, even with the industry average SOR declining from today's level of 3 to 2 by 2035. Although the hydrogeology of the oil sands area is not fully understood at first, ultimately the groundwater resources prove productive enough to support the growing water demand.

The incredible pace of development of oil sands in this scenario highlights the important role of the Oil Sands Secretariat in optimizing plans for economic development, sustainable environmental objectives, and infrastructure developments. The Secretariat creates several

*Not all water used in mining operations is drawn from the Athabasca River. Even in 2008 a substantial share of water was drawn from site runoff and mine dewatering.

smaller communities in the Regional Municipality of Wood Buffalo that allow workers to live closer to their jobs, taking the pressure off Fort McMurray as well as minimizing temporary housing. This change leads to more sustainable and socially harmonious communities. Diversion of royalty money from the province to the Regional Municipality of Wood Buffalo is very important in this scenario to allow needed infrastructure improvements to support the growing population, including investments in transportation, health care, education, and other community services.

DEEP FREEZE SCENARIO: KEY INSIGHTS

Insight 1. The world oil price is the number one driver of oil sands production. Even though costs decline sharply by the end of the scenario in Deep Freeze, bitumen prices still need to reach over $30 per barrel (constant 2008 US dollars) in 2035 to support investment—a level above the benchmark light, sweet crude oil price at that time.

Insight 2. A prolonged period of low oil prices could lead to a drastic decline in valuation for many operators in the oil sands. This could create the opportunity for companies with strong balance sheets to acquire oil sands operations at deep discounts. Consolidation in the industry would be likely, with multinationals taking over independents.

Insight 3. Oil sands operators will need to ensure they have access to downstream markets in a world in which demand is stagnant or decreasing. Vertical integration between upstream producers and downstream processors could therefore become more critical.

Insight 4. Downstream investments are at risk in a low price environment. Pipelines have been built and oil companies are retooling their refineries in anticipation of rising supplies of bitumen in this scenario. However, if production growth of oil sands stops, these refineries may find themselves competing for limited supplies of oil sands supplies and bid up the price.

Insight 5. Although large greenfield investments are unlikely in this scenario, plummeting construction costs could give an advantage to incumbent producers looking to expand production of existing facilities. Operating costs for existing producers are also relatively low in this scenario.

Insight 6. In a low oil price environment the pace of technology advances in the oil sands sector could be surprisingly strong. Pressures to keep costs in line will be intense and technology will be part of the solution.

Insight 7. Absent transformational technology adoption, the most important driver of GHG emissions growth in the oil sands is the pace of production growth, not adoption of new carbon abatement technology. CCS and nuclear are not deployed in the Deep Freeze scenario, yet GHG emissions growth is the weakest in this scenario since output growth stalls.

Insight 8. The economic benefits accruing to Canada from the oil sands industry in this scenario would be relatively weak. In addition to lower annual revenue, by 2035 there would be fewer jobs directly and indirectly related to the oil sands than currently.

A LOST DECADE: THE ECONOMIC AND ENERGY CONTEXT OF DEEP FREEZE

Economic growth is one of the key drivers for oil demand and oil prices. What if the great recession that took hold in 2008 and 2009 is just the prelude to a "great stagnation"? What if globalization—the prevailing economic paradigm of the past several decades—loses ground to the forces of nationalism, insularity, and protectionism? How will the Canadian oil sands fare in such a challenging world of lower economic growth?

These are the key premises explored in the Deep Freeze scenario. In this scenario there is a sense throughout society that unfettered free markets have failed. The "commanding heights" of the economy shift back toward governmental control, with greater political and regulatory oversight throughout the economy. And yet this shift to a greater role for government does not result in a rebound in economic growth—rather, the economy stagnates. Oil prices remain at depressed levels, reflecting a long period of anemic world demand. In this environment high-cost, marginal sources of oil—such as the Canadian oil sands—face a long fight for survival.

A Prolonged Economic Disaster and a "Super Slump" for Oil Prices

By 2010 it is clear that the financial and economic crisis that began in 2008 is becoming the "great stagnation." Deep and intractable structural problems within the US economy and indeed the greater world economy continue to fester, despite massive government spending. The economic fallout has serious political ramifications. A simmering frustration with globalization and its effects on the economy, society, culture, and economic security emerges into full backlash in many countries—from North America and Europe to developing economies in Asia. The whole essence of globalization comes much more into question, and a wave of insularity begins to sweep through many countries and regions. The result is a period of increasing bank failures, economic stagnation, and growing protectionism. Beggar-thy-neighbor sentiment starts to creep into the global political-economic landscape.

The decade from 2010 to 2020 is one of sustained low global economic growth—only averaging 2.5 percent, compared with 4.5 percent achieved from 2003 to 2008. Demand for most commodities, including oil, remains weak. Oil demand in North America only begins to grow again consistently post-2020. Oil prices enter a "super slump," with the light, sweet crude benchmark hovering just below $30 per barrel in constant 2008 US dollars ($34 in nominal terms) from 2010 to 2020.

By the second decade of the scenario the world economy has begun to recover. However, the overhang of spare capacity in the world oil market keeps oil prices relatively weak, and prices continue to drift downward, averaging only about $25 per barrel in constant 2008 US dollars ($41 in nominal terms) from 2020 to 2035. In this scenario global liquids demand growth increases only 14 mbd from 2009 to 2035—annual average incremental growth of only about 550,000 bd.

Energy Security Remains Important as Geopolitical Unrest Spreads

Deep Freeze is also a world of heightened global tensions and political insecurity. The sense of global community gives ground to renewed nationalism and separatism. Episodes of terrorism as well as the proliferation of nuclear and other weapons contribute to the environment of fear and uncertainty.

Geopolitical instability in the Deep Freeze scenario magnifies the importance of energy security to major oil importers such as the United States. Despite the low oil price environment, there is a strong desire in the United States to reduce dependence on “foreign oil” through development of domestic resources and imports from “friendly” and secure countries. In this respect Canadian oil and gas reserves are high on the list of secure supplies. Even in this scenario of low oil sands production, Canada’s share of total US crude imports still climbs to 23 percent by 2035.

OIL SANDS DEVELOPMENT: WAITING FOR THE THAW

Without question, the economic and oil price environment of Deep Freeze is the most challenging of the three scenarios for Canadian oil sands producers. The oil sands boom is now followed by the great—and long—bust.

With light, sweet crude prices hovering below $30 per barrel in constant 2008 US dollars ($34 in nominal terms), operating projects in the oil sands are able to just cover their cash costs, but the economics of new oil sands investments are dismal. Only new projects well into their construction phase now proceed, leading to some continued growth in the early part of the scenario’s first decade. By 2013 production has reached 1.8 mbd, but the development process for new oil sands projects comes to a virtual halt. Overall capacity growth has stopped. Once initial momentum subsides, the industry is basically in a deep freeze.

A generational retreat from growth in oil sands production in such a scenario is not preordained, however. Several factors allow some moderate production growth by the second decade of the scenario:

- **Declining costs support incumbent producers.** Reduced project activity throughout the energy sector and depressed commodity prices lead to a steep decline in capital costs (50 percent from 2008 peak in real terms by 2035). Capital costs do not drop enough to allow for an adequate return on investment for new oil sands investments, but they do drop low enough to allow existing capacity to conservatively expand production.

- **A recovery in oil demand.** A sustained period of low prices ultimately leads to a recovery in oil demand by the second decade of the scenario. Expensive alternatives to petroleum such as biofuels and electric vehicles do not thrive as much as in other scenarios.

- **A weaker emphasis on carbon mitigation.** A poorly performing world economy results in only marginal increases in carbon emissions in this scenario. Expensive schemes to price carbon are seen as counterproductive in such a low growth world.

Small Consolation for Producers: Lower Costs and Competition for Bitumen

There is a faint silver lining for oil sands producers amid the wreckage of the bust: capital costs for new projects plummet from their 2008 highs.

Initially, as the slowdown in Alberta and other oil producing regions around the world reduces demand for equipment, labor, and services, capital costs drop 20 percent through 2010 from their 2008 peak. Post-2010 the rate of cost decline continues, although at a more moderate pace. Prices for many project components hit the "cost floor"—their cost of production. Prices for other commodities such as steel and cement remain low amid weak world economic growth and sluggish demand for these key inputs. In this scenario, especially the first half of the period, the number of suppliers for engineering and oilfield equipment exceeds demand, keeping downward pressure on project costs.

A low number of oil sands–related projects, combined with few energy-related projects in North America, keeps the Albertan labor market much looser than it had been previously. From 2010 to 2020 demand for craft labor in Alberta evaporates, averaging less than 5,000 mobile workers (compared with a peak of over 36,000 workers in 2008)—less than 25 percent of Alberta's supply of workers. Real labor costs decline as a result (resulting from increased productivity, wage freezes, and decreased costs for incentives such as per diem payments and bonuses) and remain relatively low throughout the remainder of the scenario.

For the highest-cost producers—bitumen upgraders—these sharp reductions in costs are not enough to offset low world oil prices. In 2015, for example, new SAGD production with an integrated upgrader requires a WTI price of more than $50 per barrel (constant 2008 US dollars) to meet a 10 percent return-on-investment hurdle rate—well above the prevailing crude prices. Although costs decline, reducing the required WTI price to $40 per barrel by the end of the scenario, this is still above the average light, sweet crude oil price. As a result, upgrader investments never recover in this scenario. However, incumbent bitumen producers are able to take advantage of lower capital costs to conservatively expand production as needed by the market. Small capacity expansions that are able to leverage existing infrastructure have positive economics, especially in the first half of the scenario period, when heavy-light differentials narrow.

Although new projects are generally uneconomic in this scenario, existing projects can cover their variable costs, which average $12 per barrel for a SAGD project and $20 per barrel for a integrated mine and upgrader project. Owing to these relatively favorable economics for incumbent producers, over 30,000 bd of capacity creep is added on average each year from 2020 to 2035 by brownfield expansion of existing facilities.

Economics and Government Incentives

Preserving and creating jobs becomes the pressing issue of the day in this scenario. Total spending related to oil sands developments averages more than C$20 billion (real 2008 Canadian dollars) per year. By 2035, 200,000 jobs are directly or indirectly related to oil sands—fewer than at the end of the great boom years of 2000–08. The vast majority of these jobs are long-term operations jobs, since minimal new construction occurs toward the end of the scenario. From 2025 through 2035 revenues to municipal, provincial, and federal governments average more than C$3 billion (real 2008 Canadian dollars) per year, less than government revenues in 2008.

With benchmark light, sweet crude oil prices averaging below $30 per barrel, royalties paid to the Alberta government are at the lowest level possible on the sliding scale. The federal government attempts to improve project economics by giving back tax incentives (removed in the 2007 budget), allowing accelerated depreciation of capital costs. However, in this crude oil price environment the Alberta or federal government can do little to improve project environments by reducing royalties or changing tax structures.

Aboriginal concerns regarding oil sands developments fall by the wayside as jobs become a high priority in the face of dramatically slowed development. The Oil Sands Secretariat faces new challenges in assessing the correct pace of infrastructure development to meet new economic realities and stimulate job creation. Through a system of royalty relief and tax credits, the Secretariat attempts to increase the incentives for upgrading and further processing initiatives (for example, field upgraders and integrated power facilities with the capability of exporting surplus power to the grid). But with oil prices remaining stubbornly low, these incentives are unable to spur new investment.

Relatively weak natural gas prices provide another small buffer for producing economics in this scenario. Natural gas supplies in Canada are relatively abundant in the Deep Freeze scenario—owing partly to the absence of a strong demand pull that a growing oil sands sector would otherwise provide. Productive capacity in the Western Canada Sedimentary Basin reaches 18 Bcf per day in 2024 and is augmented by an additional 2 Bcf of gas flowing from the Mackenzie Delta starting in 2023. Gas prices slump initially, along with crude oil prices, with Alberta hub prices dropping to under $3 per MMBtu (constant 2008 US dollars) by 2020. Gas prices rise modestly in the second half of the scenario.

Intense operating cost pressure in Deep Freeze motivates continued advances in technology. These are evolutionary in nature but result in a continued lowering of SORs in SAGD projects to an average of 2 by the end of the scenario, together with improvements in drilling, downhole pumps, use of hydrocarbon solvents, and steam distribution.

Bitumen producers have another small consolation in this scenario. Although absolute crude oil prices are low, bitumen pricing is relatively robust at the start of the scenario. This occurs as several US Midwest refineries retool their facilities during 2009 to 2016 to process over 600,000 bd of additional diluted bitumen instead of conventional crude oil. Over 1.6 mbd of pipeline capacity to ship bitumen to these markets is also completed during this time. These refining and pipeline projects were conceived, planned, and begun before the economic crisis, when bitumen supplies were expected to be plentiful and pricing advantageous to refiners.

As new oil sands projects are halted, however, these refineries—which have now completed costly revamps of their facilities to specifically run bitumen—must compete for now-limited bitumen supplies or switch crude slates and absorb the high costs incurred with processing crudes that are not optimal for their facilities. The scarcity of heavy crude in North America is magnified by continued declines in heavy crude production in Mexico and Venezuela. Indeed, production declines from these traditional heavy crude suppliers accelerate from 2010 to 2020, as the low world oil price prevents them from making the type of large-scale investment needed to shore up production.

As a result of this tightening balance for heavy crude, bitumen's discount to light, sweet crude oil is narrow during the first part of this scenario, and bitumen trades above the price of similar heavy, sour crudes in the US Gulf Coast such as Mexican Maya. Deep conversion refiners that are exposed to this narrowing differential face a poor return on investment as a result, and new investments in deep conversion refining capacity are scrapped. Planned pipelines to the US Gulf Coast and Canada's west coast are similarly canceled. These are an unambiguous market signal to oil sands producers to keep major new investments on hold.

In this scenario diluent is initially in short supply until a pipeline is finished that can recycle diluent from Chicago (along with diluent supplies brought up from the Gulf Coast) back to producers in Edmonton. At this point diluent becomes relatively oversupplied, as the pipeline exceeds the required amount of diluent.

Oil Demand Comes Out of Hibernation

By 2020 oil demand in North America is finally on the upswing, stimulated by the prolonged period of low oil prices in the previous decade and a resumption of stronger economic growth. Oil sands productive capacity growth resumes tentatively. Expansion is largely a result of debottlenecking efforts and modest brownfield investments, since the oil price remains too low to support large-scale new investments. Average annual growth from 2020 to 2035 is only 30,000 bd, and new capacity additions slow to less than 20,000 barrels per year for the last ten years, limited to brownfield expansion of existing bitumen production since upgrading economics remain out of reach. The growth in world oil demand is primarily met by lower-cost oil fields, not the oil sands.

Gas demand for oil sands production reaches 1.5 Bcf per day in 2035 for in-situ and mining, while gas demand for upgrading reaches 1.1 Bcf per day in 2035. With gas relatively plentiful and prices modest, alternative technologies such as petroleum coke or asphaltene gasification or in-situ combustion techniques are not needed and not developed commercially.

The Environment: The Impact of Lower Growth

In the Deep Freeze scenario's grim world of sustained low economic growth, environmental issues gain less traction. Although international discussions continue on a new climate change protocol, no real progress occurs as all countries now focus on the more pressing issue of restarting economic growth. The urgency to act quickly on climate change also declines owing to a significant slowdown in growth of GHG emissions. The rate of fossil fuel consumption growth moderates in line with slower economic activity. Although this slowing in emissions growth does not result in a significant change in atmospheric accumulation of GHG, it does reduce public alarm about growing emissions.

Discussions to limit GHG emissions at the global level break down in Copenhagen in 2009, and as a result the United States and Canada both continue to delay on the issue. In the interim some of the state and provincial policies move forward, but with little fanfare and with limited success at actually reducing emissions. However, the issue of carbon abatement does not fade completely, and by 2025 a carbon cap-and-trade program is negotiated between the United States and Canada. However, CO_2 prices are capped and held below $10 per metric ton (constant 2008 US dollars).

With carbon prices low and less urgency to develop new technologies for carbon abatement, CCS is not commercially developed in the Deep Freeze scenario. As a result oil sands GHG emissions grow under this scenario. By 2035 GHG emissions associated with oil sands production climb to about 60 mt per year, accounting for about 8 percent of total Canadian GHG (an increase from about 5 percent in 2008). The overall emissions in the Deep Freeze scenario are lower than in the other two scenarios, despite the absence of carbon-abatement technologies such as CCS, nuclear, and in-situ combustion techniques. Adoption of these technologies reduces emissions intensity, but slower growth in oil sands production has the biggest impact on aggregate emissions.

The deep and prolonged economic downturn means that oil sands projects must be managed in a world of slow growth and poor project economics. The implementation of recently enacted regulations on tailings management and water recycling is delayed as a way of preserving the economic viability of existing projects. New targets are set in keeping with the industry's ability to pay in a low growth and low oil price environment. Nevertheless, some improvements are made in water use and tailings management. Mining operations reduce fresh water use and store water to avoid exceeding the Athabasca River's winter low-flow withdrawal limits. The relatively small amount of water that needs to be stored in this scenario means that each operator decides on its own summer month water storage strategy, such as adding extra water to its existing tailings ponds or using mined-out areas to store water inventories. The expense and technological challenge of dewatering tailings results in only incremental progress in eliminating fluid fine tailings. Since little water is available to recycle from tailings, the rate of mining water use remains relatively stagnant in this scenario at approximately 4 barrels of water for every barrel of bitumen produced. Ultimately, EPLs are required to store tailings in the reclaimed landscape, and the pace of reclamation is slow as operators struggle to pay for reclamation efforts. Research on wetlands restoration stalls due to lack of funding, and reclaimed land consists primarily of highland forest and EPLs.

CHAPTER V: CONCLUSION

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INNOVATION ACROSS ALL SECTORS

When Dr. Karl Clark cracked the code to separate the oil from the sand nearly a century ago, it was the first of many challenges that were overcome in the story of the Canadian oil sands. Innovation has been a continual part of the story ever since. In the 1990s cooperation between government and private industry led to the development of steam-assisted gravity drainage (SAGD), one of the major techniques that offers a way to unlock the 80 percent of oil sands resources that are too deep to mine. Indeed, the history of the oil sands shows how the cumulative effect of innovation, research, government policy, and private capital have made the oil sands one of the most important sources of oil supply growth in the past decade and potentially in the decades ahead.

As a result, the oil sands today have moved from the fringe of energy supply to the center. Their commercial development makes Canada the world's second largest holder of recoverable oil reserves and an increasingly important part of the fabric of hemispheric and global energy security. The development of this oil resource has become an important source for economic growth. The oil sands have become a vital element in the $597 billion of US-Canadian trade and the overall relationship between Canada and the United States. They are a major part of the network of energy trade—involving also conventional oil, natural gas, and electric power—that binds the two nations together. They have made Canada the largest oil exporter to the United States, connected by pipelines and adjacency. They have the potential for significant future growth, contributing further to supply and security and helping to provide balance for the global energy system. Recognizing the significance and impact of oil sands is very important, and approaching the questions about oil sands in an appropriate fashion is essential. To do otherwise is to risk wider disruption in US-Canadian relations, with significant economic and security impacts.

But new challenges face the oil sands industry. The world's most severe economic downturn in decades has cast a chill on many investment plans. Also, like other energy sources, the oil sands will be affected by the future path of greenhouse gas (GHG) regulation in Canada and the United States. Sometimes, however, there is a tendency to take the current status quo, a moment in time, as the fixed outline for the future. But innovation is not static. Since 2000, the amount of steam used in SAGD has been cut in half, significantly reducing GHG emissions on a per-barrel-of-output basis. As in the past, technology and process advancements will lead to greater efficiency and new ways of doing things, which in turn will enhance investment economics and improve the GHG footprint of oil sands.

How will the oil sands evolve? The pace of their development could move in several different directions, as illustrated by our scenarios. Realization of the oil sands potential, while also requiring environmental protection, means finding an appropriate balance among governments, oil sands operators, investors, local communities, and nongovernmental organizations.

But how is a balance to be found? Moving toward a shared understanding of benefits and risks is essential to productive dialogue among stakeholders. That means getting the GHG question into a comparable framework, which indicates that the oil sands, on a well-to-wheels basis, add about 5 to 15 percent more GHG than the average barrel consumed in the United States. This places them within the general range of crude oils consumed in the United States. Productive dialogue also means clarifying the other environmental and social issues, from tailings to the pace of economic development, and identifying solutions. Our study highlights the important role for government-supported research and development (R&D) to address the environmental challenges. Also important is recognizing the range of uncertainty and timing about future economic growth, oil prices, regulation, and technological advancements.

We hope that as a result of the wide participation in our study workshops by a range of organizations, combined with CERA's eight months of research, this study can contribute to finding an appropriate balance on oil sands development that meets economic and security objectives and, at the same time, safeguards the environment.

APPENDIX A: PROJECT TEAM BIOS

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Daniel Yergin, *IHS CERA Chairman – Study Chairman,* is a highly respected authority on energy, international politics, and economics. Dr. Yergin is a recipient of the United States Energy Award for "lifelong achievements in energy and the promotion of international understanding."

Dr. Yergin received the Pulitzer Prize for his work *The Prize: The Epic Quest for Oil, Money and Power*. The book has been translated into 17 languages and has just been released in a new updated edition.

Of Dr. Yergin's subsequent book, *Commanding Heights: The Battle for the World Economy*, the *Wall Street Journal* said, "No one could ask for a better account of the world's political and economic destiny since World War II." It has been translated into 13 languages.

Dr. Yergin is writing a new book on the challenges of energy, geopolitics, and climate change.

He chaired the US Department of Energy's Task Force on Strategic Energy Research and Development. He is a member of the Board of the United States Energy Association, and a member of the US National Petroleum Council. He recently served as Vice Chair of the new National Petroleum Council study, *Facing the Hard Truths about Energy.* He is one of the "Wise Men" of the International Gas Union.

He serves as CNBC's Global Energy Expert.

Dr. Yergin was awarded the Medal of the President of the Republic of Italy for combining "an understanding of the dynamics of the market with a broad view of the forces of geopolitics as he seeks to point the way to the positive outcomes for the world community."

He is a Trustee of the Brookings Institution, on the Board of the New America Foundation, and on the Advisory Board of Energy Initiative at the Massachusetts Institute of Technology and the Advisory Board of the Peterson Institute for International Economics. He is also a Member of the Singapore International Advisory Panel on Energy.

Dr. Yergin holds a BA from Yale University and a PhD from Cambridge University, where he was a Marshall Scholar.

Dr. Yergin cofounded IHS Cambridge Energy Research Associates. Its offices are in Cambridge, Massachusetts; Beijing; Calgary; Dubai; Houston; Mexico City; Moscow; Oslo; Paris; San Francisco; Sao Paulo; Singapore; Tokyo; and Washington, DC.

David Hobbs, ***IHS CERA Vice President and Head of Research – Study Advisor,*** is an expert in energy industry structure and strategies. He previously led CERA's research activities in oil markets and strategies, liquefied natural gas, technology, and environmental strategies.

Mr. Hobbs is an author of the major CERA studies *In Search of Reasonable Certainty: Oil and Gas Reserves Disclosures*, a comprehensive analysis of the problem of assessing reserves, and *Modernizing Oil and Gas Disclosures.* He is also a principal author of the CERA Multiclient Study *Harnessing the Storm—Investment Challenges and the Future of the Oil Value Chain* the author of the CERA Private Report *Daring to Be Disciplined: Continuous Portfolio Improvement*, and a project advisor to the CERA Multiclient Study *Crossing the Divide: The Future of Clean Energy.*

Prior to joining CERA, Mr. Hobbs had two decades of experience in the international exploration and production business. Mr. Hobbs holds a degree from Imperial College.

James Burkhard*, Managing Director of IHS CERA's Global Oil Group – Study Director*, leads the team of CERA experts that analyze and assess upstream and downstream business conditions and strategies, including short- and long-term outlooks for global crude oil and refined products markets. Mr. Burkhard's expertise covers geopolitics, world economic conditions, and global oil demand and supply trends.

Mr. Burkhard was the project director of *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030*, the most comprehensive study that CERA has ever undertaken, encompassing the oil, gas, and electricity sectors. He was also the director of the CERA Multiclient Study *Potential versus Reality: West African Oil & Gas to 2020*, and a project advisor to the CERA Multiclient Study *Crossing the Divide: The Future of Clean Energy.* Mr. Burkhard served on the US National Petroleum Council (NPC) committee that provided recommendations on US oil and gas policy to the US Secretary of Energy. He led the team that developed demand-oriented recommendations that were published in the 2007 NPC report *Facing the Hard Truths About Energy.* Mr. Burkhard holds a BA from Hamline University and an MS from the School of Foreign Service at Georgetown University.

Jackie Forrest, ***IHS CERA Director, Capital Costs Analysis Forum – Study Manager,*** has more than a decade's experience in the definition and economic evaluation of refining projects. Her expertise encompasses all aspects of petroleum evaluations, including refining, processing, upgrading, and products, with a focus on oil sands. As the research lead for CERA's Capital Costs Analysis Forum—Downstream, she is responsible for analyzing global costs markets and monitoring emerging strategic trends related to downstream projects. She is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University.

James R. Meitl, ***IHS CERA Senior Director, Business Development,*** is a senior account specialist focusing on western US regional markets and strategies. Based in Calgary, he has extensive experience in problem solving, strategy development, and market development. He holds an MPA and a BSc from the University of Kansas.

Samantha Gross, *IHS CERA Associate Director,* Global Oil, specializes in helping energy companies navigate the complex landscape of governments, nongovernmental organizations, shareholders, and other stakeholders when making investment decisions. Her recent contributions to CERA research include reports on peak gasoline demand in the United States, US vehicle fuel efficiency regulations, international climate change negotiations, and the increasing demands placed on international oil companies by governments in resource-rich countries. Ms. Gross was also the CERA Project Director for *Thirsty Energy: Water and Energy in the 21st Century*, produced in conjunction with the World Economic Forum. Before joining CERA she was a Senior Analyst with the Government Accountability Office, where she managed a study of the role and capability of the US Strategic Petroleum Reserve, led an analysis of US refining capacity and inventory practices, and prepared congressional testimony on electricity risk management practices, among other energy projects. Ms. Gross holds a BS from the University of Illinois, an MS from Stanford University, and an MBA from the University of California at Berkeley.

Aaron F. Brady, *IHS CERA Director,* Global Oil, is an expert in the global oil market, including downstream price dynamics, political and regulatory influences, and economic trends. His analyses focus on the fundamentals of the North American refined product markets and on energy/environmental legislation and regulatory issues, including the role of biofuels. Mr. Brady is a regular contributor to CERA's global oil retainer research, providing market analysis on supply and demand fundamentals and key trends in the global downstream industry for both CERA's *World Refined Product Outlook* and the *World Oil Watch*. He was the lead author of the biofuels segment of CERA's Multiclient Study *Crossing the Divide: The Future of Clean Energy*. Mr. Brady holds a BA from Amherst College and an MA from Johns Hopkins School of Advanced International Studies.

Roger J. Goodman, *IHS CERA Senior Consultant,* is an authority on natural gas, coal, and electricity market trends. He specializes in strategy, scenario planning, technology, marketing, and business development. For nearly 15 years, Dr. Goodman was employed in a variety of senior management positions with Shell Canada Limited in strategic and scenario planning, business development, and marketing, especially in natural gas, electricity, sulfur, and liquids. He has also held senior management positions in the Canadian government in the areas of trade promotion, metals, minerals, and energy specialist and headed Canadian delegations as a technical expert at international meetings of United Nations Conference on Trade and Development, United Nations Industrial Development Organization, and the OECD. Dr. Goodman is the author of several CERA reports, including analyses of coal commoditization; power generation; fuel cells; hydrogen; Canada's Kyoto compliance strategies; and Canada's electric power and fuels sectors including nuclear, hydro, natural gas, and coalbed methane. Dr. Goodman holds a BA from Carleton University, a BSc (Honors) from the University of Wales in Cardiff, and a DPhil from Oxford.

Tiffany A. Groode, *IHS CERA Associate Director,* focuses on critical issues for CERA's Driving the Future: Energy for Transportation in the 21st Century Forum. Her expertise includes modeling and analyzing the environmental impacts of ethanol production by performing life-cycle uncertainty analysis as well as assessing the potential scale of bioethanol production from various biomass sources. While working at the Sloan Automotive Laboratory at the Massachusetts Institute of Technology (MIT), Dr. Groode presented her bioethanol results and conclusions to a variety of national government agencies to provide insight for policy decisions. Dr. Groode holds a BS from the University of California, Los Angeles, and an MS and PhD from MIT.

Rob Barnett, *IHS CERA Associate Director,* specializes in energy sector economics, environmental policy and strategy, and emissions markets. Mr. Barnett is responsible for CERA's North American emission price outlooks and regularly contributes to CERA's global retainer research by providing insight on the impact of environmental policies, interfuel competition, technology choice and environmental markets. He is the author of numerous CERA reports on topics including the US clean air rules, cost recovery for pollution control expenditures, and European emissions trading. Recently, he contributed to the environmental market analysis for CERA's Multiclient Study *Crossing the Divide: The Future of Clean Energy*. He also contributed to the CERA Multiclient Study *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030* and to *Clearing the Air: Scenarios for the Future of US Emissions Markets*. Mr. Barnett holds BS and MS degrees from Clemson University and an MA from Boston University.

William R. Veno, *IHS CERA Director,* Global Downstream, is an expert on crude oil and refined product markets, on refining and marketing, and on energy economics and strategy. Mr. Veno is a leader of CERA's global refining and marketing research activity, with particular expertise in North American refined product demand, the transportation sector, and refined product pricing. He contributes to CERA's quarterly *World Refined Products Outlook* and coordinated the oil demand analysis for the CERA Multiclient Study on global energy scenarios, *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030*. He directed the CERA studies *Gasoline and the American People 2007*, *Westward Flows and Refiners' Woes: The Growing Role of Imports in US Gasoline Supply*, and *Global Oil Trends*. He has participated in several National Petroleum Council studies, including analyses of petroleum product supply, the cleaner fuels value chain, and fuel inventory dynamics.

Previously Mr. Veno was Senior Petroleum Economist at Petróleos de Venezuela (USA) in New York, responsible for short- and long-term oil market analysis for the US and global markets, and had similar responsibilities as a Senior Analyst with Conoco and the US Department of Energy. Mr. Veno holds a BS from the University of Notre Dame, an MS from Dartmouth College, and an MS from Columbia University

Matthew T. Palmer, *IHS CERA Associate Director,* provides analysis of Western gas market fundamentals and is an expert on natural gas demand issues in North America. He provides oversight on analysis and forecasts for the residential, commercial, and industrial sectors of the North American gas market, and has recently examined how recent trends in weather have affected natural gas demand as well as the impact different climate normal's have upon natural gas demand forecasts. Mr. Palmer has examined the long- and short-term relationship between oil and natural gas prices in North America, including a thorough analysis of the factors that cause convergence and divergence between them. He is also a coauthor of CERA's *North American Natural Gas Watch* and of the *Monthly Gas Briefing* and has contributed to the CERA *Global Energy Watch.* Additionally, Mr. Palmer contributes to the ongoing development of the global scenarios through CERA's Global Energy Forum and also contributes to the North American Gas and Power Scenarios Forum.

Mr. Palmer holds a BS and an MS from the University of Massachusetts at Amherst.

Jonathan M. Craig, ***IHS CERA Associate,*** Global Oil Supply, is a specialist in global liquids production and capacity and in oil industry activity. Mr. Craig is the primary contributor to CERA's analytic application *Global Oil Capacity Outlook*, which provides CERA's view on future global liquid production capacity through a unique combination of country-level capacity outlooks, comprehensive data compilations, and an understanding of factors driving liquids capacity and production. Mr. Craig's work is also a major component of CERA's worldwide liquids capacity and E&P Trends Forum research.

Before joining CERA Mr. Craig worked for IHS Energy for over eight years, the last four as regional manager of IHS Global Exploration and Production Services, covering the northern Middle East, providing detailed information on exploration and production activity in the region. Previously he worked on exploration drilling operations in the UK North Sea. Mr. Craig holds a BSc from the University of Manchester.

Randy J. Mikula, ***CanmetENERGY Technology Centre – Team Leader, Extraction and Tailings,*** has more than 20 years experience in researching oil sands tailings behavior, including water chemistry and clay interactions. Projects have included pilot- and commercial-scale demonstrations of the gypsum consolidated tailings (CT) process, as well as work on carbon dioxide (CO_2) as a CT process aid. This research involves investigation of the fundamental chemistry of the CO_2–clay interaction, including CT formation mechanisms and the potential for CO_2 sequestration. The program of fundamental research, directed at oil sands tailings handling solutions has been a powerful combination. This has resulted in varied opportunities to discuss his work, ranging from testifying as an expert witness to public lectures on the role of nanotechnology in oil sands development ("Visioning Alberta's Future: The role of Nanotechnology in the Oil Sands Industry"). Most recently, Dr. Mikula has coordinated the scientific program around development and pilot-scale demonstration of centrifuged fluid fine tailings at Syncrude, a program that will likely grow to a commercial demonstration. Dr. Mikula has a PhD in chemistry from the University of British Columbia and BSc in chemistry from the University of Saskatchewan. He also is a Fellow of the Canadian Institute of Chemistry.