Challenges Facing the
Development of the Athabasca Oil Sands

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View of Syncrude Plant, Fort McMurray, Alberta, Canada
MTW, 19 August 2006

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ABSTRACT

In the 21st century, the world will face unprecedented challenges regarding economic development and environmental change. At the intersection of economic development and environmental change lies energy. In order to meet the growing demand for energy, especially fossil fuels such as oil, production from existing suppliers has increased and new resources, such as the oil sands of Northern Alberta, Canada, have become economical to develop. Canada has the world's second largest oil reserves after Saudi Arabia, most of which are contained in the Athabasca oil sands, which span over 100,000 square kilometers and contain an estimated 174 billion barrels of recoverable oil. While this vast reserve resides in a politically stable country close to the largest oil market in the world, its development still faces significant challenges.

The National Energy Board (NEB), a federal regulatory agency, projects that production in the oil sands will double from 920,000 barrels per day in 2003 to 1.8 million barrels per day in 2010, putting the timing of this thesis in the middle of the current rapid development. In the five years after 2010, the NEB expects production to increase to 3 million barrels per day. The manufacturing of synthetic crude oil from the oil sands has significant environmental and economic consequences that Alberta must address in the coming years. The oil sands are a rapidly changing industry, and many regulatory and governmental policies are under intense scrutiny because of changes in both the physical and economic scale of operations.

While the Athabasca oil sands face significant technical, environmental, economic, and growth-related challenges, this is an unprecedented opportunity to explore how Alberta will chart future development. Chapter 1 will introduce the oil sands to the

reader and Chapter 2 will explain the methods of synthetic crude oil production. Chapters 3 and 4 will observe and examine current and future production from a quantitative and qualitative perspective. Chapter 5 will analyze the consequences of the growth of the oil sands, and Chapter 6 will offer recommendations for the future.

Overall, this thesis will conclude that the continued profitability of the oil sands industry is at risk from increasing capital and operating costs and that its development creates untold and potentially enormous consequences for the environment. The oil sands industry, however, due to current economic circumstances, is too integral to the Alberta economy to have a moratorium placed on its development, and therefore these challenges must be overcome through policy-induced environmental and economic change. The thesis will recommend that the following actions be taken to mitigate the environmental and economic consequences of the rapid and expansive development that will take place in the coming years: 1) that the Province of Alberta chart new policy directions based on the precautionary principle, 2) that Albertans demand reforms in the independent research organizations and the provincial ministries that study and oversee the oil sands development, 3) that Alberta estimates the environmental cost of production, and 4) that the province explores alternative development futures.

Chapter 1: Introduction to the Oil Sands

1.1 Meeting the Energy Supply Challenge

In the 21st century, the world will face unprecedented challenges regarding economic development and environmental change. As industrialization and modern lifestyles spread to the farthest corners of the globe, the habitable world will become increasingly crowded and its resources increasingly stressed. At the intersection of economic development and environmental change lies energy. Supplying world energy needs for the next century, allowing for both economic growth and the preservation of the environment, is a global problem. The solution to this issue will affect how and where we will live, work, and travel, thus requiring the collaboration of environmental, economic, political, social, and scientific interests.

Historically, fossil fuels such as coal, oil, and natural gas, have supplied the bulk of the energy required by industrialized economies. Oil, especially, is vital to the world energy economy, being the primary source of transportation fuels. The cost and availability of oil is of particular concern in developed countries due to their reliance upon petroleum to transport both finished goods and an ever-more-mobile labor force. The United States Energy Information Administration estimates that oil consumption will grow "from 80 million barrels per day in 2003 to 98 million barrels per day in 2015 and 118 million barrels per day in 2030," an average rate of growth of 1.4 percent per year.[1] Sustaining this growth in production will require both improved technology and additional oil resources. It is difficult to estimate the true amount of total global oil resources, since the use of more sophisticated exploration and technological improvements frequently increases the amount of recoverable oil. Despite better technology, the fact remains that since the 1970s oil shock, energy policies have been at the forefront of national and international politics.

For several decades, the United States, in particular, has been concerned about energy security, both because of political instability in the Middle East and declining domestic production. Public attention has been turned to the Arctic National Wildlife Refuge, ethanol production in the Midwest, and oil shale in the Rocky Mountains as potential supplies of oil-derived gasoline. In recent years, however, attention has also been focused on growing production north of the border in Canada, especially in the oil sands of northern Alberta. The Alberta oil sands have 40 times the estimated reserves of the Arctic National Wildlife Refuge.[2] While not all energy statisticians recognize the

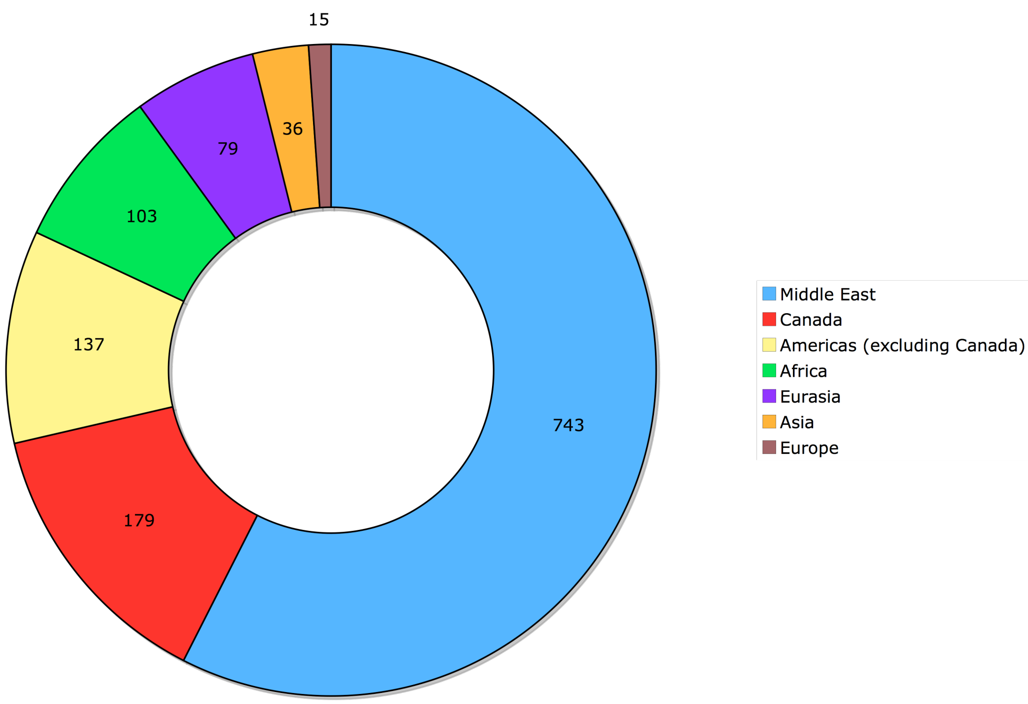


Figure 1. World Proved Oil Reserves by Geographic Region, measured in billions of barrels. Note Canada holds a significant portion of the world's proved oil reserves. (Source: EIA)

bitumen constituting Alberta's reserves as an equivalent crude oil reserve, *Oil and Gas Journal* changed its accounting of Canadian reserves in 2002 to include the 178.8 billion barrels of oil sands considered recoverable with current technology. The result of this single change was that "OPEC's share of the world's oil reserves [decreased in one day] by more than 10 percentage points."[3] The significance of this reserve addition, placing Canada second only to Saudi Arabia in terms of reserves (see Figure 1), cannot be understated.[4] Daniel Yergin, an oil industry expert at Cambridge Energy Research Associates, told a U.S. Senate committee in April 2003 that "although almost completely overlooked, something very important has just happened. [There has been a] significant decline in the Persian Gulf's share of total world oil reserves."[5]

The growth of the oil sands has already altered the balance of U.S. oil imports. At the beginning of 2006, Canada replaced Saudi Arabia as the most important supplier of oil to the U.S.. [6] Additionally, in 2006, production from the oil sands exceeded production in Alaska's North Slope or production in Texas. [7] The Canadian Association of Petroleum Producers predicts that the growth of the oil sands will propel Canada to the fourth largest producer of crude oil in the world, behind Russia, Saudi Arabia, and the United States.[8] Alberta's oil sands have for Canada a reserve ratio of 475 years, or for the world a reserve ratio of 15 years.[9] The concept of a reserve ratio is a standard industry term used to indicate how long the resource would be able to produce at the current production rate (reserve volume ÷ production/year). The largest portion of the oil sands resource, the Athabasca deposit, has a land area of 102,610 square kilometers, or approximately 15 percent of the province, which is five times the size of the Commonwealth of Massachusetts (see Figure 2).[10]

Figure 2. Comparison of Oil Sands Mines and Metro Boston Aerial Photographs. Oil sands mines are located in the Athabasca oil sands, a few kilometers north of Fort McMurray, in the Regional Municipality of Wood Buffalo. Each photograph is 40km x 40 km. Compare size of Syncrude open pit mine (at left) to Cambridge (highlighted at right). (Source: ASPER 20 Nov 2004, Google Earth).

While this vast reserve resides in a politically stable country close to the largest oil market in the world, its development still faces significant challenges. The techniques for extracting bitumen from the oil sands and producing synthetic crude oil from it are well established. Further research and development, however, is necessary to reduce operating costs and reduce environmental impacts. On the economic side of the equation, the rapid growth in the oil sands region and instability in world commodity markets has led to volatility in project economics, while, more locally, the oil sands have led to changing socioeconomic structures and raised many political issues in Alberta on how to best develop the resource. Despite the size of Alberta's resource, these challenges will prevent the oil sands from being an energy security panacea for oil consumption in the United States and Canada (see Figure 3).

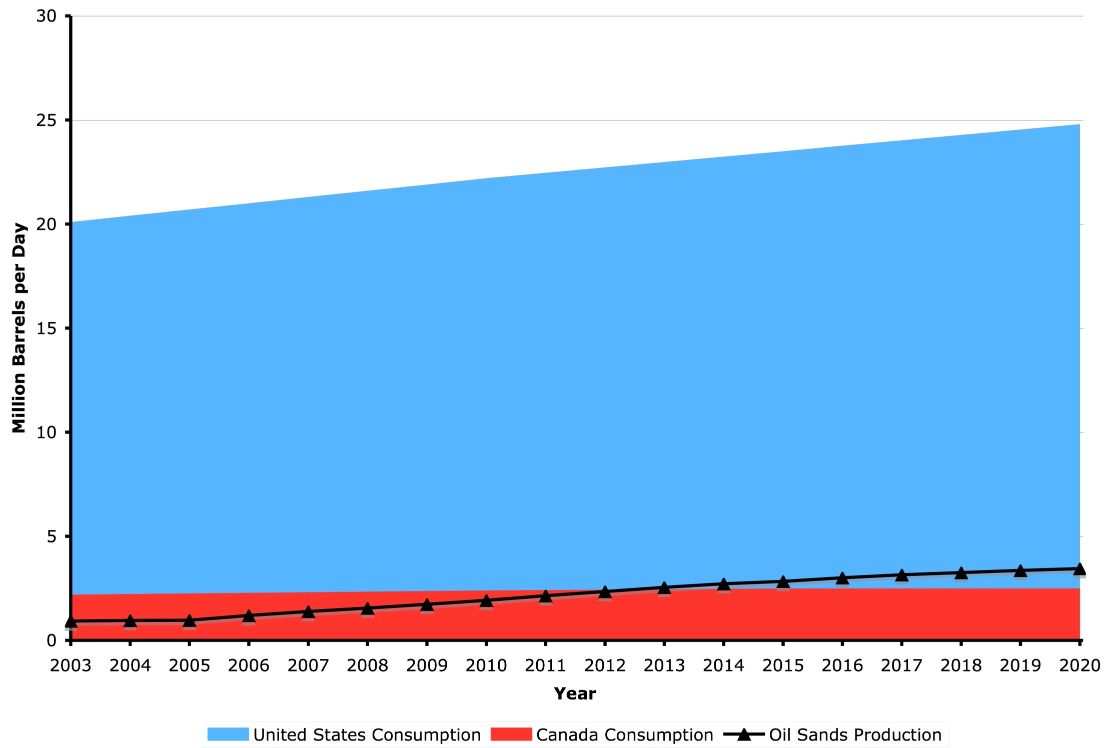


Figure 3. Comparison of Projected Canada Oil Consumption, Projected U.S. Oil Consumption, and Projected Oil Sands Production. Although the oil sands are a world-class proved reserve, their projected production will pale in comparison to the increase in American and Canadian consumption. (Source: EIA, average of various production projections).

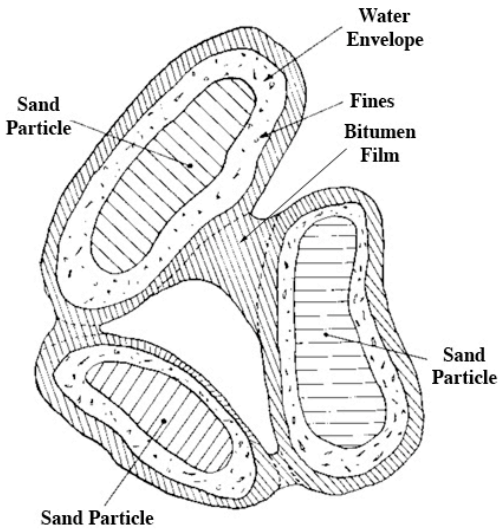
Nevertheless, the growth in production has been unexpectedly rapid, with policies formulated in 1996 to encourage the production of one million barrels per day by 2020 actually resulting in that level of production by 2004 (see Figure 3).[11] In an interview with *Rolling Stone* magazine, former vice-president and current climate campaigner Al Gore referred to the energy requirement and landscape consequences of oil sands development as "truly nuts."[12] Nonetheless, as Stéphane Dion, the former Canadian environment minister and now leader of the Canadian Federal Liberal Party states, "there is no environmental minister on earth who can stop the oil from coming out of the sand, because the money is too big."[13] Perhaps Paul Chastko, a historian of the oil sands, summarizes the current situation in Alberta best, saying that "the oil sands have tremendous potential, but it also has the whiff of political dynamite about it.…The bornand-bred Albertan in me says I should be shouting from the highest rooftop about how the oil sands are going to pave the way for our future. The historian in me recognizes that rarely are things ever so unique."[14]

Traveling to Alberta in summer 2006 in order to conduct research for this thesis, I quickly realized the scale of oil sands operations. To put these projects in perspective with national symbols, Syncrude's upgrader expansion, a small $7.4 billion component of its plant site, required 15,000 more cubic meters of concrete than Toronto's CN Tower and a third as much steel as San Francisco's Golden Gate Bridge.[15] But numbers alone cannot convey the magnitude of the industry. As such, I have chosen a variety of media, including historical information, current descriptions, scientific analysis, statistical charts, and photographs in an attempt to represent the challenges facing the development of the Athabasca oil sands.

This thesis is the first recent consolidation of information on the oil sands into a comprehensive academic analysis. There is a need for both a thorough review of the current development and an analytical treatment of the environmental, economic, and political challenges facing future development, as the magnitude of these issues are well known, but their effects are not. This first chapter will introduce and frame the oil sands in an academic context, focusing on their geology, geography, history, and current status. The following chapter will discuss the different methods of bitumen separation and upgrading. Building upon the production techniques, the third chapter will examine the environmental consequences and concerns of current and future oil sands development. The fourth chapter will analyze the economic factors influencing the oil sands industry. Synthesizing chapters two through four, the fifth chapter will investigate the consequences of the oil sands' growth. The sixth – and final – chapter will recommend development approaches based on technology, environmental science, economics, and public policy. While the Athabasca oil sands face significant technical, environmental, economic, and growth-related challenges, this is an unprecedented opportunity to explore how Alberta will chart future development. Overall, this thesis will conclude that the continued profitability of the oil sands industry is at risk from increasing capital and operating costs and that its development creates untold and potentially enormous consequences for the environment. The oil sands industry, however, due to current economic circumstances, is too integral to the Alberta economy to have a moratorium placed on its development, and therefore these challenges must be overcome through policy-induced environmental and economic change. The thesis will recommend that the following actions be taken to mitigate the environmental and economic consequences of the rapid and expansive development that will take place in the coming years: 1) that the Province of Alberta chart new policy directions based on the precautionary principle, 2) that Albertans demand reforms in the independent research organizations and the provincial ministries that study and oversee the oil sands development, 3) that Alberta estimates the environmental cost of production, and 4) that the province explores alternative development futures.

1.2 Geology and Geological History of the Oil Sands

In order to understand fully the technical and economic challenges facing the development of the Athabasca oil sands, it is critical to understand the geology of the deposit that makes this a unique resource. Oil sands are hydrophilic sand particles surrounded by a coating of water, which are in turn enveloped in a film of bitumen (see



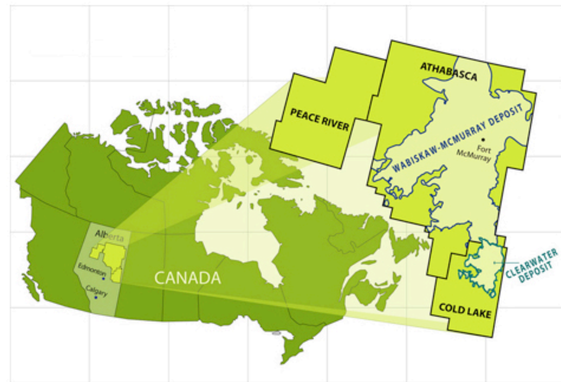


Figure 4. Diagram of Oil Sands. (Source: Oil Sands Discovery Centre)

Figure 5. Map of Oil Sands in Relation to Alberta and Canada. (Source: EUB)

Figure 4).[16] The water envelope and hydrophilic nature of the sand is important; if the sand grains were oleophilic, the oil would soak into the sand particle, making extraction of the bitumen commercially infeasible.[17] The triangular sand particles are extremely hard and abrasive, due to a high content of quartz (92 percent), with some feldspar, mica, and clay minerals such as kaolinite. The grains are very fine to fine (62.5 to 250 micrometers) and are well-sorted, with high porosity (25 to 35 percent).[18] The percentage content of bitumen in oil sands varies greatly, from approximately one to 18 percent by mass, with deposits containing more than 6 percent bitumen by mass considered economically recoverable.[19]

Bitumen is a mix of complex, long-chained hydrocarbon molecules, which result in a composition of 83.2 percent carbon, 10.4 percent hydrogen, 4.8 percent sulfur, 0.94 percent oxygen, 0.36 percent nitrogen, and trace amounts of methane, hydrogen sulfide, nickel, iron, and vanadium.[20] Due to its molecular weight, bitumen is heavier than conventional crude oil. The density of crude oil is measured on the American Petroleum Institute (API) gravity scale, with a lower number of degrees corresponding with denser

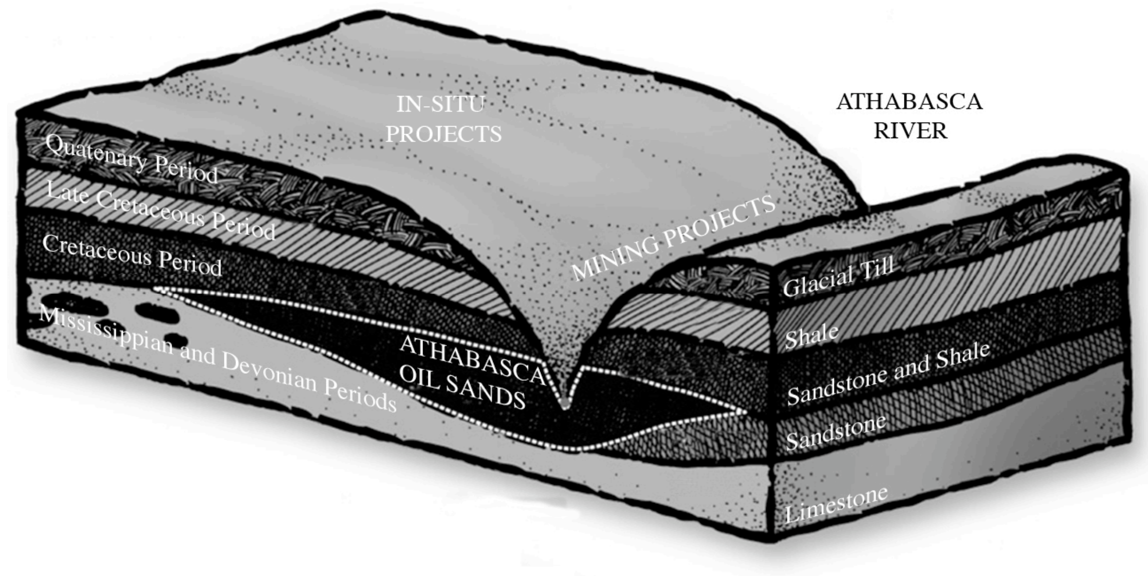


Figure 6. Cross-section of the Athabasca Oil Sands at Fort McMurray. Note the Athabasca River cutting into Wabiskaw/McMurray Formation, yielding surface mineable deposits. (Source: Oil Sands Discovery Centre).

oil. Bitumen, with an API of <14˚ as compared to an average weight crude oil of 25˚ to 35˚, or a benchmark crude oil blend such as the West Texas Intermediate (WTI) of 38˚ to 40˚, is too viscous for recovery via traditional petroleum drilling techniques or for transport via pipelines.[21] In order to be refined into commercial products, bitumen must be first upgraded to synthetic crude oil.

Oil sands are located in deposits around the world, with the largest in Venezuela and Canada. While up to 1.2 trillion barrels of heavy oil are in the Faja de Orinoco in Venezuela, Canada's deposits are even larger with at least 1.6 trillion barrels of bitumen.[22] Canada's oil sands deposits are located in Alberta, where there are three major oil sands areas, all of which are under commercial development – Athabasca, Cold Lake, and Peace River (see Figure 5). The Athabasca oil sands reserve, the subject of this thesis, is the largest and the closest to the surface, and therefore has the longest history of development.

Geologists believe that approximately 110 million years ago plankton grew in a

Figure 7. Confluence of the Athabasca and Clearwater Rivers at Fort McMurray, flowing north towards the oil sands mining sites. Note the cliffs on the eastern bank that show darker bituminous strata near their base. (MTW, 20 Aug. 2006)

shallow sea that covered present-day Alberta.[23] After burial of the organic matter, bacterial action, temperature, and pressure transformed the debris into the oil deposits that can be found throughout the province.[24] This oil resided in a Devonian reef carbonate formation above the Precambrian basement structures, and migrated north and east when the Rocky Mountains formed (see Figure 6).[25] Fifty million years ago, the oil migrated more than 100km upwards and entered Cretaceous surface clastic sediments, saturating sand deposits in ancient river beds. The oil then biologically degraded into bitumen via microbial action.[26]

Most of the Athabasca oil sands are in the Wabiskaw/McMurray Formation, with additional deposits in the Clearwater Formation to the south and west. While the general geology of the region can be inferred from sedimentary faces displayed on cliff outcrops along the Athabasca River (see Figure 7), test boreholes for mining and in-situ projects have demonstrated significant variation from the outcrops (see Figure 8). At the base of the formation is a thick bed of cross-stratified sands above the Devonian limestone with inclined strata, with the sands ranging from well to poorly sorted, indicating several different conditions for deposition. Above this, there are horizontally bedded sands and silts, leading up into the glacially weathered Clearwater Formation.[27] The overburden

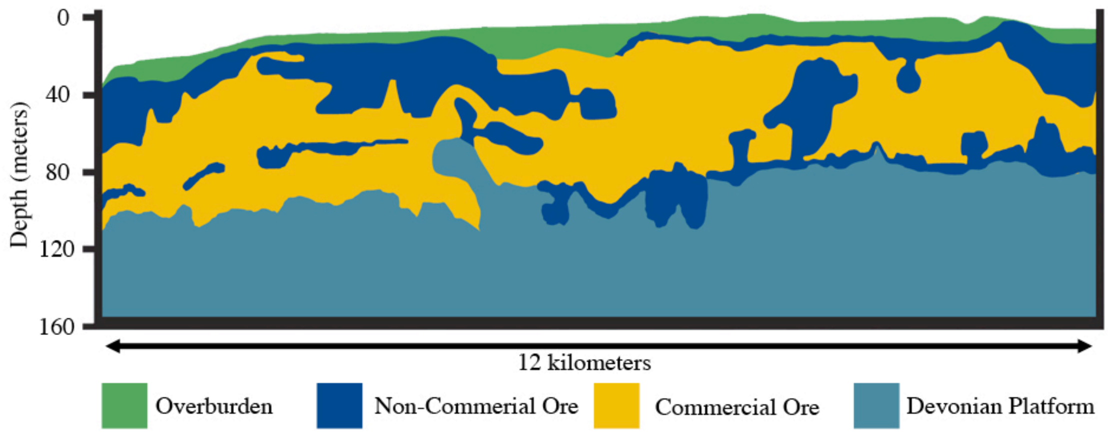


Figure 8. Cross-section of Syncrude's Aurora North Mine. Note interspersed non-commercial ore with commercial ore. (Source: Syncrude)

above the oil sands deposits is composed of glacial deposits, sandstone, shale, and muskeg.[28] Muskeg consists of boreal vegetation, sphagnum moss, and detritus, averaging two to six meters in depth. While geological studies differ as to the specific paths of action, all agree that the sedimentary deposits were the result of a meandering paleofluvial channel and floodplain that experienced marine interactions.[29]

1.3 History of Oil Sands Development

In order to understand the political pressures influencing the development of the oil sands, it is necessary to explore the history of the development of the bitumen resource. This historical narrative can be grouped into four major themes: expectations of the resource's economic potential, research and development relating to extraction, the Alberta government's role in the oil sands, and the federal/provincial political divide.

Europeans, such as Peter Pond in 1778, first entered the region of northern Alberta in pursuit of fur trading and commercial exploration.[30] There was no written record of the oil sands until the explorer Alexander Mackenzie's account in 1788. "At about [40 kilometers] from the fork [of the Athabasca and Clearwater Rivers] are some bituminous fountains into which a pole of [6 meters] long may be inserted without the least resistance."[31] "The bitumen", he continued, "is in a fluid state, and when mixed with gum, or the resinous substance collected from the spruce fir, serves to gum the canoes. In its heated state it emits a smell like that of sea-coal. The banks of the river, which are there very elevated, discover veins of the same bituminous quality."[32] Several other explorers and travelers noted the presence of the oil sands, but the origin of the oil sands remained a mystery.

In 1870, the Dominion of Canada purchased the lands of the Hudson's Bay Company (including northern Alberta), opening up 6.5 million square kilometers to the development and usage of natural resources.[33] In the following decades, the federal government sent forth the Geological Survey of Canada (GSC) as a vanguard of future western expansion. In 1884, Robert Bell, a professional geologist with GSC, wrote a prescient description of the oil sands and their commercial potential. "…The banks of the Athabasca would furnish an inexhaustible supply of fuel…[they] have found it to contain from 12-15 per cent bitumen. Although this proportion may appear small, yet the material occurs in such enormous quantities that a profitable means of extracting oil…may be found".[34] In addition to speculating as to the commercial value of the oil sands, Bell correctly identified the source of the "vast quantities of somewhat altered petroleum" as Devonian limestone.

These early energy explorers' speculation over the resource's economic potential gave way to scientific research and development. Around the time of World War I, oil was recognized as an increasingly important resource, and the oil sands accordingly became an area of great interest. At that time, and for the several decades afterwards, the research of Karl Clark dominated the oil sands landscape and led to him being the best-known early oil sands pioneer. Clark's research on the behalf of the provincial government's Alberta Research Council was instrumental in developing industrial-scale processes for oil sands separation.[35] In 1928, Clark patented his hot water extraction process, which forms the basis of bitumen extraction and separation used in mines today.[36] These developments enabled the Athabasca oil sands' first commercial separation and refining facility, Robert Fitzsimmons' International Bitumen, in the 1930s.[37] A few years later, Abasand Oils, owned by Max Ball, began production.[38] While both of these operations would ultimately be commercially unsuccessful, their business practices and experiences were instructive.

This led to a period of significant government intervention in the oil sands. During World War II, the Canadian federal government supported Abasand Oils based on energy security needs.[39] Ottawa's involvement, however, was essentially a failure. Abasand was never able to produce a significant amount of crude oil to supply the wartime energy needs, marking an unsuccessful attempt at an early Canadian national energy policy.[40] Most importantly, the federal government's foray into the Athabasca oil sands set two important precedents that have subsequently governed commercial development. The first was that the oil sands could only be developed with significant government and industry cooperation. The second was that Alberta would be ever wary of the federal government's forays into what were deemed the province's natural resources.[41] As historian Paul Chastko notes, "for the Province of Alberta, the oil sands were not just the answer to a wartime shortage of fuel. They represented the potential of a multimillion-dollar energy industry in a predominantly agrarian prairie province."[42]

Beginning with Alberta's first Premier Alexander Rutherford in 1905, the province has always fostered a strong relationship between government and commercial development interests.[43] With this political framework, the natural response to the encroachment of the federal government was for Alberta to develop its own oil sands project, Bitumount, in 1945.[44] While Bitumount was to encounter its fair share of problems, it was an experimental success.[45] The growth of the commercial development of the oil sands would now hinge on economic constraints rather than technical limitations.[46] Nevertheless, government involvement remained a necessary stabilizing force for industry to begin to take hold.[47] The Alberta oil production landscape radically changed in 1947 with the discovery of conventional crude oil at Leduc #1 south of Edmonton (and 435 kilometers southwest of Fort McMurray). This find threatened to sideline the commercial development of the oil sands.[48] Despite a discouraging Eisenhower administration study of the Canadian oil industry, the oil sands piqued the interest of J. Howard Pew of Sun Oil, based in Philadelphia, Pennsylvania. Pew wrote:

> No nation can long be secure in this atomic age unless it be amply supplied with petroleum. It is the considered opinion of our group that if the North American continent is to produce the oil to meet its requirements in the years ahead oil from the Athabascan area must of necessity play an important role.[49]

Pew, Alberta Premier Manning, and the Great Canadian Oil Sands (GCOS) company came to an agreement on October 2, 1962, to begin commercial production in the oil sands.[50] The complications of production and financing were readily apparent, and there were substantial risks involved with the startup of GCOS for both investors and government alike.[51] GCOS started production in 1967, albeit with difficulties sustaining production and maintaining skilled labor in the harsh environment north of Fort

McMurray.[52] In addition, the government royalty structure taxing synthetic crude was seen as ineffective, and as the historian Paul Chastko notes, "GCOS's experience demonstrated that the economic viability of any future commercial oil sands projects depended on the provincial royalty regime."[53] Another government-industry consortium, Syncrude, moved ahead towards building its own mining and upgrading plant in the Athabasca oil sands, which began production in 1978. Syncrude faced the same problems as GCOS, such as the lack of infrastructure in Fort McMurray, the high cost of technological implementation, risky project management, and unpredictable government involvement.[54] Nevertheless, predictions for the growth of the oil sands were optimistic, with a 1978 *Science* magazine article predicting production of one million barrels per day by the early 1990s, a target not reached until the present decade.[55]

The oil shocks of the 1970s ushered in another wave of increased government involvement in the oil sands. Increasing federal interest in energy matters, and the oil sands more specifically, led to a provincial-federal conflict between Alberta Premier Peter Lougheed and Canadian Prime Minister Pierre Trudeau, which was complicated by another oil shock in the early 1980s. Trudeau's National Energy Program (NEP) created animosity and distrust between Ottawa and Edmonton and left the oil industry in limbo.[56] As a result, in 1981, Imperial Oil (an Exxon subsidiary) postponed a $12 billion oil sands development and Shell Canada postponed a $13 billion mining project.[57] These announcements left Alberta economically shaken and demonstrated that companies would pull out their interests if project economics were not to a company's satisfaction.

1.4 Recent History and Challenges Facing the Development of the Athabasca Oil Sands

The changeover of the federal government in 1984 to Prime Minister Brian Mulroney brought an end to the National Energy Program, increased free trade with the U.S., and better provincial-federal relations.[58] Alberta experienced a similar sea-change of policies with the 1992 election of Premier Ralph Klein, who promoted the business-friendly "Alberta Advantage."[59] New policies and visions dominated the 1990s, as evidenced by the formation of the Alberta Chamber of Resources' National Oil Sands Task Force in 1995. The findings of the Task Force recommended research and development systems, a generic royalty structure, and a vision towards the ultimate market potential of the bitumen and synthetic crude oil.[60] The business climate created by this report in the late 1990s, along with recent improvements in technology, led to the beginning of the current, phenomenal rate of growth in the oil sands.[61] On June 3, 1996, Prime Minster Jean Chrétien visited Fort McMurray as a symbolic opening of the oil sands, heralding both a standardized generic royalty structure and billions of dollars of new investment.[62]

The resulting growth of the oil sands industry has spawned an entirely new set of challenges that now face the development of the resource. The oil sands industry, once composed of just the mining companies Suncor (formerly GCOS) and Syncrude, now has many different players and two very different extraction techniques – open pit mining and in-situ extraction. Major operators in the oil sands include Suncor, Imperial Oil, Shell Canada, and several other multi-national companies. These organizations are represented by the Canadian Association of Petroleum Producers (CAPP), an industry

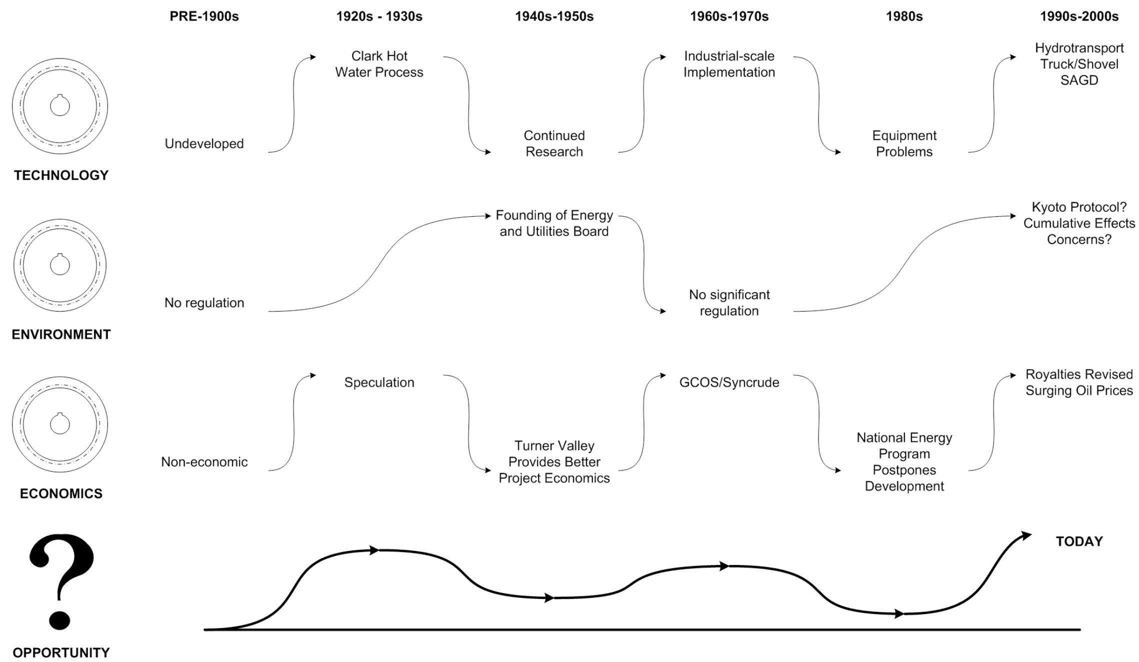


Figure 9. Schematic diagram of how the three cogs of oil sands growth have historically interacted to create opportunity.

interest group. The only major environmental NGO in the oil patch is the Pembina Institute, which is concerned with the environmental and socioeconomic effects of resource extraction in the oil sands. Many provincial government ministries oversee parts of the development in the oil sands. The primary ones are Alberta Environment, Alberta Energy, and the Alberta Energy and Utilities Board (EUB, a semi-independent project-approval body). In the past few years, federal officials, led by the pipeline-regulating National Energy Board (NEB), have shown an increasing interest in how the oil sands are to be developed. As Alberta frequently uses consultations to formulate policy, all of the groups have a significant voice representing their respective constituents.

With recent leadership changes in both Ottawa and Edmonton and several mega-projects recently approved or awaiting approval by the EUB, the present moment appears to be an appropriate time for reflection. In fact, this may be an historic moment where Albertans may define a precedent for how non-conventional oil will be developed. In this thesis, the reader will see that the three cogs of the oil sands – process technologies, the environment, and economics – are all at the forefront of concern, a situation unprecedented in the oil sands history (see Figure 9). New technologies for in-situ and mining production have been implemented in the past decade, and future processes still in the research and development phase look even more promising. The already large environmental impacts of the oil sands are set to increase rapidly despite provincial and federal regulations on the horizon. Finally, high capital and construction costs have begun to upset project economics and change socioeconomic dynamics across the province. Therefore, there is a pressing need both to understand how these stakeholders have interacted in an historical cycle and to understand the implications of growth on the environment and the economy. This thesis will explore the current situation (see Figure 10), the consequences of future growth, and possibilities for the future based on technology, environmental science, economics, and public policy.[*]

[*] This thesis will use units of measure familiar both to the reader and to the literature. Prices will be in U.S. dollars. Oil will be measured in barrels. Other volumes, masses, and distances will be measured using the metric system. The word "tons" will refer to metric tons throughout the thesis.

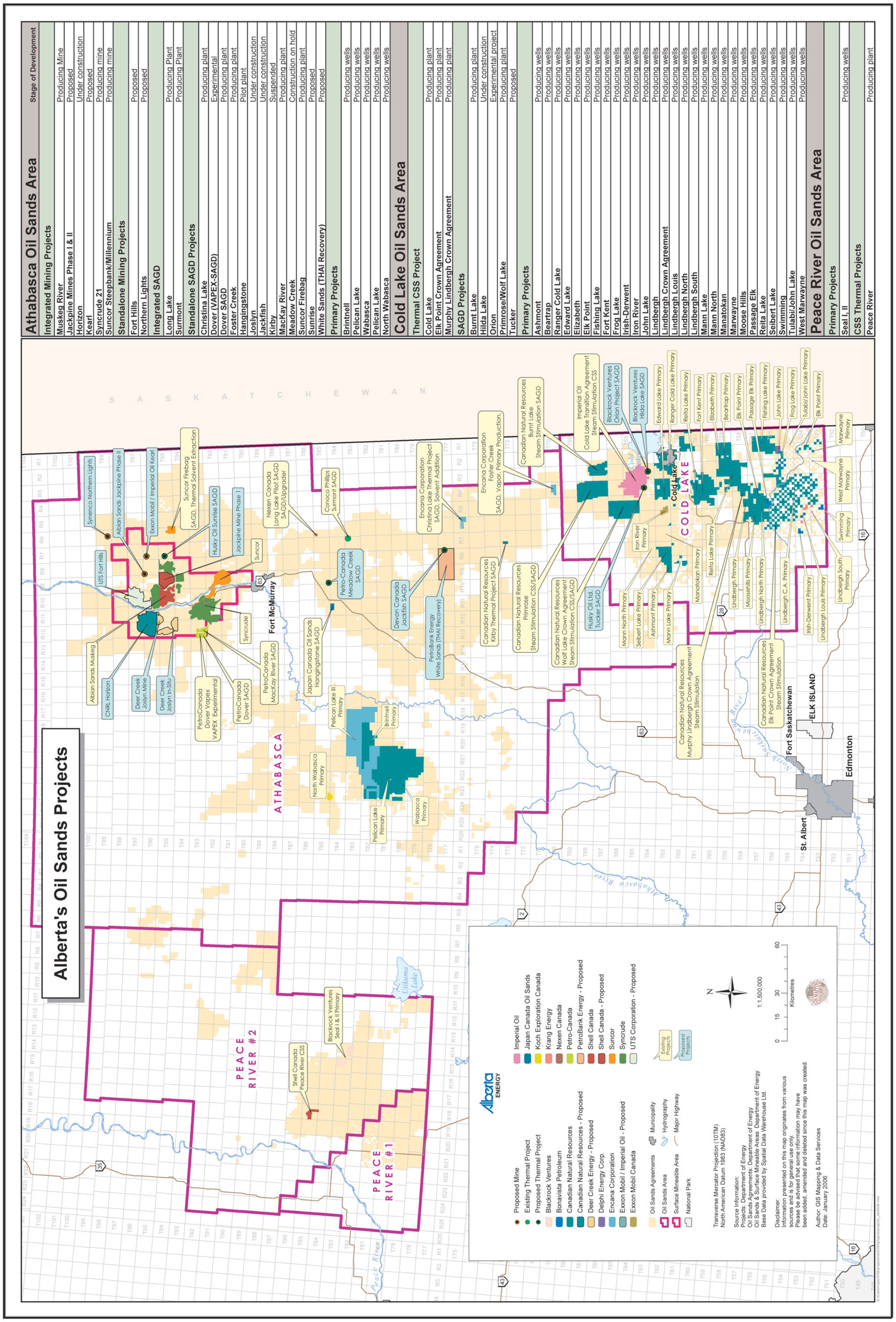


Figure 10. Alberta's Oil Sands Projects (Source: Alberta Energy)

Chapter 2: Production Techniques

The oil sands have had a long history of process innovation necessitated by the continual need to reduce operating costs and capital expenditures. As much of this technology is unique to the oil sands, a thorough understanding of the production techniques is necessary to comprehend the environmental and economic issues in Chapters 3 and 4. Therefore, this chapter serves as a primer on the methods used in oil sands production and will support the observations, analysis, and conclusions in later chapters. The discussion of production techniques is divided into three parts: first, a description of two bitumen extraction methods – mining and in-situ; second, an overview of upgrading, which converts the extracted bitumen into synthetic crude oil; and third, an analysis of the projected growth of the oil sands. Throughout this discussion, the scale and efficiency of operations will be emphasized, so as to provide the foundation for later quantitative analysis.

2.1 Mining

The first financially successful operation in the oil sands in 1967 used industrial-scale open pit mining near the Athabasca River. Open pit mining remains the technique producing the greatest amount of bitumen from the oil sands today. This method can be used when the bitumen deposits are less than 100 meters below the surface. Only seven percent of the total oil sand area, however, meets this requirement, necessitating the use of a second method, in-situ extraction, in other areas.[1] In-situ extraction will be discussed later in this chapter.

Before the oil sands can be accessed for open pit mining, it is necessary to drain, remove, and store for reclamation two tons of overburden (muskeg, overlying rock, and

Figure 11. Panorama of Syncrude's North Mine. (MTW, 19 August 2006)

non-commercial grade oil sands) for every barrel of synthetic crude oil to be produced. After overburden removal, two tons of oil sands must be mined and processed to produce one barrel of synthetic crude oil.[2] When these rates of mining are scaled up, as they must be in open pit mines in order to take advantage of economies of scale, the amount of material moved is astounding. In 2001, in order to produce an average of 223,000 barrels of oil per day (81.4 million barrels of synthetic crude oil in the year), Syncrude removed 175.4 million tons of overburden and mined 164.7 million tons of oil sands.[3] The mines themselves are enormous; Syncrude's original mine, the Base Mine, was seven kilometers long by seven kilometers wide by 60 meters deep, or two-thirds the size of Manhattan Island, and its current primary mine, the North Mine, is 4 kilometers long by 2.5 kilometers wide by 80 meters deep (see Figure 11).[4]

Mining on this scale requires specialized earthmoving and processing equipment. Mining facilities used to deploy massive 6,200 ton crane-mounted shovels called draglines to "walk" along the top of the mine face and reach into the open pit with an 110 meter boom. Using a 68 cubic meter bucket, the dragline piled oil sand from the mine face into mounds called windrows.[5] The oil sand was then removed from the windrow by

Figure 12. (Left) Retired Syncrude Dragline. Note saplings for scale.
(MTW, 20 August 2006)

(Right) Retired Syncrude Bucketwheel Reclaimer. Note bus for scale.
(MTW, 20 August 2006)

a bucketwheel reclaimer, a 2,400 ton machine 140 meters long with multiple buckets on a 13.4 meter diameter rotating wheel. The bucketwheel reclaimers loaded the oil sand onto conveyors that traveled across the mine, delivering material back to the base plant.[6] At the peak of this technology, Syncrude, a mining facility, had four dragline and bucketwheel reclaimer pairs, the last of which was retired in 2005 (see Figure 12).[7] Because of the harsh climate of northern Alberta and the highly abrasive oil sands, these mechanical pairs were difficult to maintain and often did not operate at peak capacity.

Shovel and truck mining was introduced in the 1990s in order to improve reliability and decrease maintenance costs. With this innovation, multiple diesel hauler trucks could be paired to many different hydraulic shovels so that the failure of any one piece of equipment would not result in a significant loss of oil sand collection productivity. Improved geological survey techniques and computer technology, when coupled with global positioning systems, allowed mining companies to match rich and lean bitumen deposits so as to have a more consistent oil sands feedstock for extraction.

Figure 13. (Left) Hauler Truck Carrying Overburden in Syncrude's North Mine. Note pickup truck for scale. (MTW, 19 August 2006)

(Right) Hauler Trucks in Maintenance at Suncor's Millennium Mine. Note Bobcat for scale. Hauler trucks can accumulate up to 3.6 tons of dirt per month and must be washed regularly. (MTW, 20 August 2006)

Shovel and truck mining allowed companies to extract accordingly, where the dragline and bucketwheel pair would have treated all oil sand as the same. These advances had enormous effects on production capability and operating costs.

The shovels currently used at oil sands mines are not as massive as yesteryear's draglines, but each still weighs 1,500 tons and has a capacity of 43 cubic meters.[8] Complementing these shovels are diesel hauler trucks that weigh up to 625 tons when fully loaded (see Figure 13).[9] These trucks are some of the largest in the world, requiring a 3550 horsepower engine to propel a vehicle the size of a two storey, three bedroom house.[10] Maintaining a fleet of these trucks is expensive, as a set of truck tires cost $175,000 to replace, and the 6800 liter fuel tanks must be refilled almost every day.[11] In addition, by stirring up dust and releasing particulate matter from the combustion of diesel fuel, these mining truck fleets have a measurable impact on the local environment.[12] Imperial Oil's Kearl mine is projected to have a fleet of 114 hauler trucks. These trucks would account for half of the project's particulate matter emissions of less than 2.5 micrometers (PM2.5), producing an aggregate 0.38 kilograms PM2.5 per hour, year round.[13] Because of their expense and environmental impact, these hauler trucks may soon be supplanted by a new technology developed by Suncor. Mobile-ore preparation equipment will be stationed near the shovels in the mine site, processing up to 5,500 tons of oil sands per hour. By crushing the ore and transporting it via conveyor belts to a nearby hydrotransport facility, these $132 million machines will replace 15 mine trucks each, resulting in significant capital and maintenance cost savings.[14]

2.2 Transport, Separation, and Extraction

Currently, the hauler trucks transport oil sands to a sand sorting and sizing machine at the center of the mine. The machine rapidly crushes the oil sand to a consistent physical composition so as not to damage downstream separation and conditioning equipment.[15] The crusher then passes the oil sand to a dump pocket where it is temporarily stored before being conveyed to a 35 meter-tall mixing vessel, the cyclofeeder, which adds warm or hot water, depending on the technologies of the plant.[16] The water addition has a two-fold purpose: first, to create a slurry that will transport the oil sand to the central processing plant and second, to initiate bitumen separation from the sand. Each of Suncor's hydrotransport lines moves more than 5 million liters of slurry per hour.[17] This early initiation of separation has enabled mining companies to reduce the original temperature of the Clark Hot Water Extraction Process from 80˚C down to a minimum of 35˚C, thereby significantly reducing energy costs.[18]

After hydrotransport to the separation facility, the slurry mixture is fed into a primary separation vessel, where the slurry is fractionated into a bitumen froth, middlings, and a sand/water mixture. The bitumen froth, which consists of 60 percent bitumen, 30 percent water, and 10 percent solids, is skimmed off the top of the separator via a weir and proceeds to froth treatment. The middlings have a higher proportion of sand, clay, and water, but still contain a recoverable amount of bitumen. The middlings enter a secondary separation process that creates froth via air injection, which recovers two to four percent additional bitumen. At the bottom of each separation tank, sand and water are raked out to enter tailings treatment. In froth treatment, naphtha (a mixture of intermediate-weight hydrocarbons) is added to the bitumen mixture, and by using either centrifuges or recently-developed inclined plate settlers, the bitumen mixture is reduced to less than 5 percent water and less than 0.5 percent solids.[19] Naphtha is recovered at the end of the treatment. The bitumen is then transported either to an onsite upgrader, or is blended with diluent (light liquid hydrocarbons such as pentanes) to be sent via long distance pipeline to an offsite upgrader for conversion to synthetic crude oil.

Bitumen separation and extraction is a resource-intensive process, due to its energy and water requirements. Approximately two to 4.5 barrels of water are withdrawn from the Athabasca River for each barrel of synthetic crude oil produced.[20] Total process water requirements, however, are much higher, as water is recycled up to eighteen times within the production operations.[21] Syncrude's 2004 production figures show that while only 2.20 barrels of water were withdrawn from the Athabasca River per barrel of synthetic crude oil produced, an additional 16.43 barrels of water were recycled, for a total of 18.63 barrels of water being used to produce a barrel of synthetic crude oil. Approximately 4 to 6 barrels of tailings, consisting of 50 to 80 percent water and 25 percent fluid fine tailings, are created by the production of each barrel of bitumen.[22] Tailings are stored in large settling and treatment basins. As Syncrude and Suncor have

Figure 14. Panorama of Suncor plant. Note holding tank and power plant at left, upgraders in middle, and settling basins next to the Athabasca River at right. (MTW 20 August 2006)

been operating for several decades, these basins have grown to enormous proportions, taking up a total land area of over 50 square kilometers, greater than two and a half times the land area of Cambridge, Massachusetts.[23]

Mining and extraction is greenhouse gas-intensive due to the significant natural gas requirement – 250 cubic feet per barrel of bitumen – for the heating of the process water. Approximately 35 kilograms of carbon dioxide equivalent (CO_2e) greenhouse gas emissions are produced per barrel of bitumen.[24] In turn, about 60 percent of these emissions result from point sources such as heat and power generation (Syncrude's power plant can provide an equivalent amount of electricity to fulfill the requirements of a city of 400,000 people), with the remaining 40 percent coming from non-point sources such as fleet emissions and fugitive emissions from the mine and tailings ponds.[25] These figures are approximate as greenhouse gas emissions are determined by "variability in bitumen quality, level of process integration, technologies applied, fuel source for electricity generation, [and] types of process controls utilized".[26]

Due to these extensive natural gas and water requirements, oil sands operators continue to research alternative processes in order to maximize operation efficiency. Shell Canada recently announced a new technology for froth treatment that it developed in conjunction with the CANMET Energy Technology Centre in Devon, Alberta for its Athabasca Oil Sands Project expansion. By increasing the temperature of the separation process, the process is expected to improve efficiency by 10 percent, reducing both water use and greenhouse gas emissions.[27] Analyzing the possible implications of this breakthrough, if companies were to implement this improved technology in all mining and extraction projects, the natural gas requirements and hence, greenhouse gas emissions, of the oil sands may be reduced significantly from their respective business-as-usual projections. In turn, this efficiency increase may alter both the operating cost structures of mining firms, yielding higher revenues on each barrel of bitumen produced, and creating an incentive for increased production.

2.3 In-Situ Production

In the past few years, in-situ production has grown rapidly as extraction technology has improved and in-situ methods have been successfully demonstrated in the field. In-situ recovery of bitumen is required in approximately 93 percent of the Alberta oil sands, since the deposits are deeper than 100 meters and are therefore unable to be mined via open pits.[28] Steam Assisted Gravity Drainage (SAGD) is the primary recovery technology used in the in-situ recovery of bitumen in the Athabasca oil sands. SAGD continuously injects heated steam underground in order to break the bitumen-water bond. After being developed by Imperial Oil in 1978, SAGD was first successfully demonstrated in 1995 at a pilot plant, the Underground Test Facility, run jointly by the

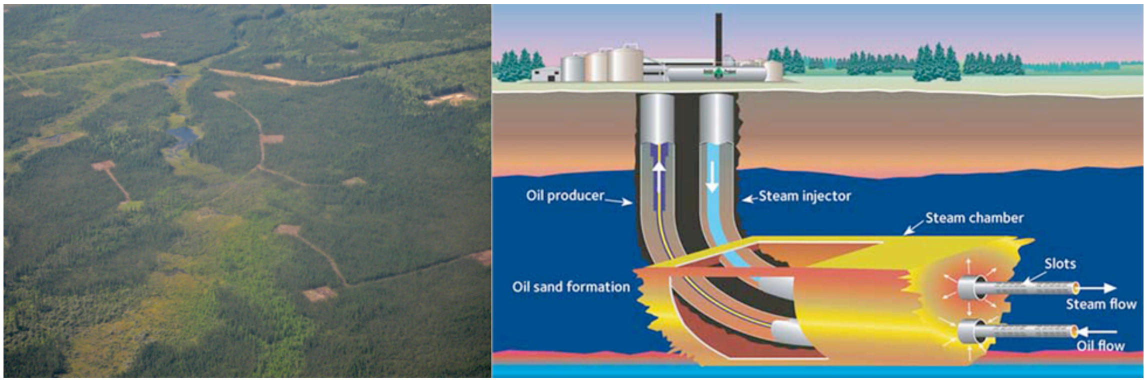


Figure 15. (Left) Aerial Photograph of Well Pads and Cut Lines on OPTI/Nexen Long Lake Lease South of Fort McMurray. Note boreal forest ecosystem of conifers interspersed with wetlands. (MTW, 21 August 2006).

(Right) Schematic Process Diagram of SAGD (Source: TORR Canada).

Alberta government, Suncor, and Syncrude.[29] SAGD was a significant technological advance that became possible with computer-assisted drilling techniques and the aid of government-funded research. The commercialization of SAGD technology may have indirectly led to *Oil and Gas Journal* including the oil sands in its resource table (as described in Chapter 1), as the production technique enables extraction from a vast majority of the total Athabasca oil sands deposit. While it has a less intense surface impact than open pit mining, SAGD still has extensive negative cumulative physical and environmental impacts. Opti/Nexen's Long Lake plant disturbs almost nine square kilometers on a 106 square kilometer site that will eventually produce 60,000 barrels of bitumen per day. While the majority of the land area is occupied by well pads and associated infrastructure (4.6 square kilometers) and processing facilities (1.3 square kilometers), there are also extensive boreal forest fragmentation impacts from access roads and supply lines that yield a linear disturbance density of 3.2 kilometers per square kilometer (see Figure 15).[30]

In SAGD, two vertically parallel horizontal wells are drilled into the subterranean oil sand deposit layers to different depths, with the shallower well injecting steam and the deeper well collecting the bitumen (see Figure 15). Ensuring the wells were parallel long distances from the wellhead was a significant challenge, as the well casings sagged under their own weight in the sand matrix.[31] In order to begin subterranean extraction, the area must first be primed with large volumes of start-up steam. Steam requirements decrease as the deposit develops and matures from three to four barrels of water per barrel of bitumen at startup to one to two barrels of water per barrel of bitumen.[32] On average, approximately 2.5 to four barrels of water and 1,000 cubic feet of natural gas are required to produce a barrel of bitumen.[33] While there is a 90 to 95 percent recycle rate for the water that is used in SAGD, the volumes of water that are used are extensive, and both groundwater usage and deep-welling (underground injection below the freshwater table) of waste water may become problems in the future. For example, the Opti/Nexen Long Lake project will require 151,000 barrels of water to recover 60,000 barrels of bitumen each day. Ten percent of this water will not be able to be recycled due to high solids concentrations, and as a result, it will be deep-welled.[34]

SAGD requires more natural gas for steam creation per barrel of bitumen production than mining, and as such, in-situ production is significantly more greenhouse gas-intensive, with approximately 55 kilograms of carbon dioxide equivalent produced per barrel of bitumen.[35] Approximately 90 percent of these emissions result from point sources such as boilers, with the remaining 10 percent coming from non-point sources such as fugitive emissions.[36] As SAGD is still a relatively young technology, there are opportunities for emission intensity reductions. These opportunities may be somewhat limited, however, as firms are keen to diversify their energy inputs in order to protect operating costs from fluctuations in natural gas prices. The Long Lake project will feature an asphaltene (heavy hydrocarbon residue byproduct from bitumen production and hence an inexpensive fuel source) gasifier that will lead to higher greenhouse gas emission intensities than a traditional SAGD facility with a natural gas fired boiler.

Due to these extensive water and energy requirements, and resulting high operating costs, there is active research into alternative in-situ technologies. Vapor recovery extraction (VAPEX) replaces the steam used in SAGD with solvents (propane, or other light hydrocarbons) in order to reduce the bitumen's viscosity. As this eliminates the need for heat energy and expensive water treatment, capital costs per well for VAPEX should be lower than for SAGD.[37] Early testing, however, has found that production rates per well using VAPEX are lower than those using SAGD.[38] Therefore, it may be necessary to build more wells in order to achieve the same levels of production, which in turn will increase a project's capital costs and environmental impacts. While at the current moment operating costs for VAPEX are projected to be lower than those for SAGD, the solvent used in VAPEX is a valuable commodity, and if widely adopted, VAPEX could increase the price of solvent dramatically, in turn increasing uncertainty in operating costs.[39] The reduction in capital and operating costs for VAPEX (the reason for switching extraction processes) appears to be uncertain, and therefore it is unclear what role the technology may play in the future.

Another technology on the horizon is Toe-to-Heal Air Injection (THAI). This uses a small amount of steam for a Pre-Ignition Heating Cycle, which prepares the geological reservoir for bitumen extraction (see Figure 16). Compressors inject air into a vertical well and the air is then ignited underground. This begins a fireflood, slowly combusting heavy fractions of bitumen such as coke that are in the oil sands deposit, creating a front that moves across the reservoir approximately 20 centimeters per day. The heat reduces the bitumen's viscosity, allowing it to be extracted via a horizontal well, as it is with SAGD. Laboratory experiments at the University of Bath in the United Kingdom recovered approximately 80 percent of the bitumen in the reservoir by increasing the API (decreasing the bitumen density) by eight degrees.[40] THAI appears to be equivalent in greenhouse gas intensity to SAGD, producing approximately 55 kilograms CO2e per barrel of bitumen.[41] Though this technology is still very much in the research phase, Soheil Asgarpour, oil sands development business unit leader for the Alberta Ministry of Energy, stated that THAI "is promising and I hope we can see some progress in that area because it will open a lot of doors for us."[42]

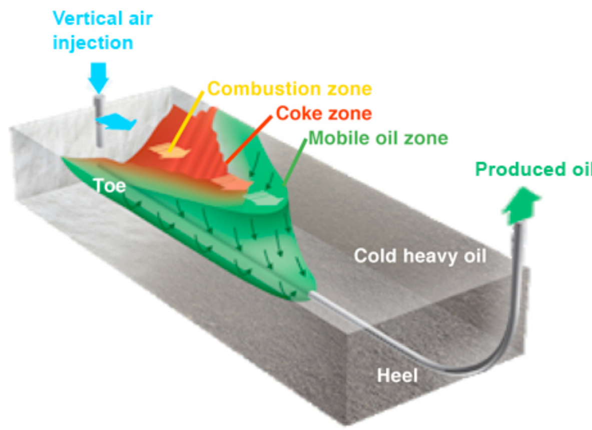


Figure 16. Schematic Process Diagram for THAI. (Source: Petrobank)

For the past several years, there has been discussion about the construction of nuclear reactors in the Fort McMurray region to produce electricity and steam. Electricity could be used for residential, commercial, and industrial purposes, whereas steam could be used for SAGD operations. As plants would produce large quantities of energy and steam at prices independent of natural gas fluctuations, advocates for nuclear power point to the reduction in operating cost variability as the main benefit of construction. While a reasonable argument in terms of economics, a central steam plant for the oil sands would be physically impossible, as facilities are spread out over a wide area and due to the fact that steam in a transmission pipeline condenses in a distance as short as 15 kilometers.[43] Even if these technical issues were to be resolved, local residents and environmental NGOs would campaign fiercely against the construction of reactors in a region already undergoing significant industrial development. With public opinion in Canada firmly against the expansion of nuclear power, the construction of nuclear power plants in the oil sands seems to be out of the question for the time being.

2.4 Upgrading Bitumen

Bitumen produced by mining and in-situ processes must be upgraded into synthetic crude oil on-site, elsewhere in Alberta, or in the U.S., before it can enter downstream refinery markets and reach the end consumer. Approximately 65 percent of the bitumen produced from the oil sands is upgraded to synthetic crude oil in Alberta.[44] Synthetic crude is subsequently processed through conventional refineries to produce a variety of traditional petrochemical products. The other 45 percent of the bitumen produced in the oil sands is combined with diluent (light liquid hydrocarbons) and pipelined to U.S. refineries and downstream markets, primarily in the Midwest. Project economics and economies of scale determine the location of upgrading facilities. Mining and extraction operations have upgraders on-site because of large energy synergies that are associated with the availability of low-quality heat from bitumen extraction water. In-situ operations, on the other hand, generally send their bitumen product to upgraders associated with mining and extraction in the region, alternatively to merchant upgraders in Edmonton and Fort Saskatchewan, Alberta, or to upgraders associated with refineries closer to consumer markets, such as those in the U.S. The economic challenges of upgrading will be further analyzed in Chapter 4.

Upgrading bitumen to synthetic crude oil decreases the viscosity of the oil by breaking up carbon-carbon bonds in the complex hydrocarbon. There are two primary methods for breaking these carbon bonds – coking and hydrocracking. Coking involves heating the bitumen to ~500˚C and removing carbon from the molecule chains.[45] This occurs in large coking units such as Suncor's Millennium cokers, that are nine meters in diameter, 35 meters tall, and weigh 422 tons. These cokers produce massive coke piles as a waste product, which can either be stored or used as a source of energy.[46] Hydrocracking, which is energy- and resource-intensive, involves using natural gas and steam to add hydrogen to the molecules, and is not as common as coking. The next step of the process, hydrotreating, also requires natural gas and steam, and is accomplished at a temperature of approximately 300˚C to 400˚C.[47] After coking and hydrotreating, the synthetic crude oil can be fractionated into naphtha, kerosene, and gas oil. At mining facilities, some gas oil is refined into diesel fuel for on-site use, and naphtha is recycled for use in the separation froth treatment process step.

As with all steps in the manufacturing of synthetic crude oil from oil sands, upgrading uses significant amounts of water and natural gas. For example, while Shell Canada's Scotford upgrader recycles 45 percent of its process water, it diverts 0.69 barrel of water per barrel of synthetic crude oil it produces from the North Saskatchewan River.[48] Statistics for water and energy usage are difficult to determine for upgrading alone as these facilities are, in general, heavily integrated with other refinery processes in order to benefit from processing synergies (sharing energy and products between two linked facilities, taking advantage of economies of scale). For steam and hydrogen creation, upgrading requires approximately 500 cubic feet of natural gas per barrel of synthetic crude oil produced. Therefore, upgrading is greenhouse gas-intensive, with approximately 45 to 80 kilograms CO2e produced per barrel of synthetic crude oil, depending on the technologies used in the facility.[49] Approximately 30 to 50 percent of these emissions are from hydrogen production for hydrotreating purposes, with approximately 50 to 70 percent originating from combustion sources such as cokers and boilers.

In addition to removing carbon and adding hydrogen to the bitumen, upgrading also removes impurities in the bitumen such as sulfur. This helps to reduce maintenance costs on equipment and to facilitate compliance with environmental regulations. The extracted sulfur is either sold as a commodity for various consumer uses (fertilizers, plastics, etc.) or stored in massive stockpiles for future use. For example, Suncor's upgrader produces 50 tons of sulfur per hour.[50] While flue-gas desulfurization units and other environmental controls have reduced sulfur emissions dramatically, a new mine upgrader could produce 0.23 kilograms of nitrogen oxides (NOx) per barrel of synthetic crude oil and 0.09 kilograms of sulfur oxides (SOx) per barrel of synthetic crude oil. These emissions per barrel of synthetic crude are 140 percent and 110 percent greater than the NOx and SOx produced by the extraction and refining of a barrel of conventional Alberta medium crude.[51]

2.5 Analysis and Growth Projections

Successfully expanding production in the oil sands will require the implementation of new technologies to improve efficiency and reliability, thereby reducing costs and uncertainties. As this chapter has described, there are many challenges ahead for the development of these extraction and upgrading technologies. Improvements in mining efficiency or retrofitting extraction and upgrading facilities are a challenge to implement because of high capital expenditures. Technological challenges are particularly apparent for in-situ projects. While SAGD has both significant water and greenhouse gas environmental impacts and high operating cost sensitivity due to natural gas usage, there is no alternative extraction technology in the short-term. It is unclear whether VAPEX will ever be an economic option, and as THAI is still in the research and development phase with only very limited pilot project implementation, it is still too early to predict its future in the oil sands.

As a capital-intensive industry, continued technological innovation will be crucial to fueling the oil sands growth and mitigating its environmental and operating cost impacts. Between 2007 and 2015, production of bitumen and synthetic crude oil from the oil sands is expected to grow from approximately 1.4 million barrels per day to 2.8 million barrels per day. This doubling of production in eight years translates into a 9 percent annual growth rate. Therefore, the oil sands industry and Alberta are extremely interested in forecasting the growth of production and its consequences. Numerous organizations have released projections in recent years including the Alberta Chamber of Resources, Canadian Association of Petroleum Producers (CAPP), Canadian Energy Research Institute (CERI), the Energy and Utilities Board (EUB), and the National Energy Board (NEB). In an August 2006 interview, the NEB described its process for formulating growth projections. First, the NEB collects historical data from the provincial government, and compares this to existing project designs and capacities. Second, the NEB analyzes start dates and design capacities of future mining and in-situ projects and applies a risk factor to each project. This risk factor is derived from the project's scale, its stage in planning, and potential supply costs. These projections, therefore, partially account for capital and labor expenditure and fluctuations in commodity prices. These risks, however, vary dramatically between each projection, generally reflecting the organization's assumptions that are based on their outlook for growth and development. Third, after discounting production from an all-projects delivered on-time scenario, the NEB takes their projection to the industry in order to confirm its accuracy. Fourth, the oil sands industry then responds with sharing data back or agreeing with the projection.[52]

Despite working from similar historical production data, estimates of future production vary greatly depending on assumptions and the current level of growth optimism. For example, in 1995, the Alberta Chamber of Resources projected that oil sands production would increase to 800,000 or 1.2 million barrels per day by 2020.[53] A production rate of 1.2 million barrels per day, the upper envelope of the projection, was reached last year, 14 years ahead of 'schedule'.[54] While projections with longer time horizons have a reduced probability of accuracy, the 1995 projection not only misgauged the investment climate created by royalty restructuring, but also could not anticipate the rise in price of crude oil and hence increased profits and returns for oil sands companies.[55] It is crucial to understand that these projections are at best informed estimates. Even as recently as 2004, the NEB predicted that production would increase to 2.2 million barrels per day by 2015.[56] Two years later, the NEB believed that production would be 36% higher with 3 million barrels of production per day by 2015.[57]

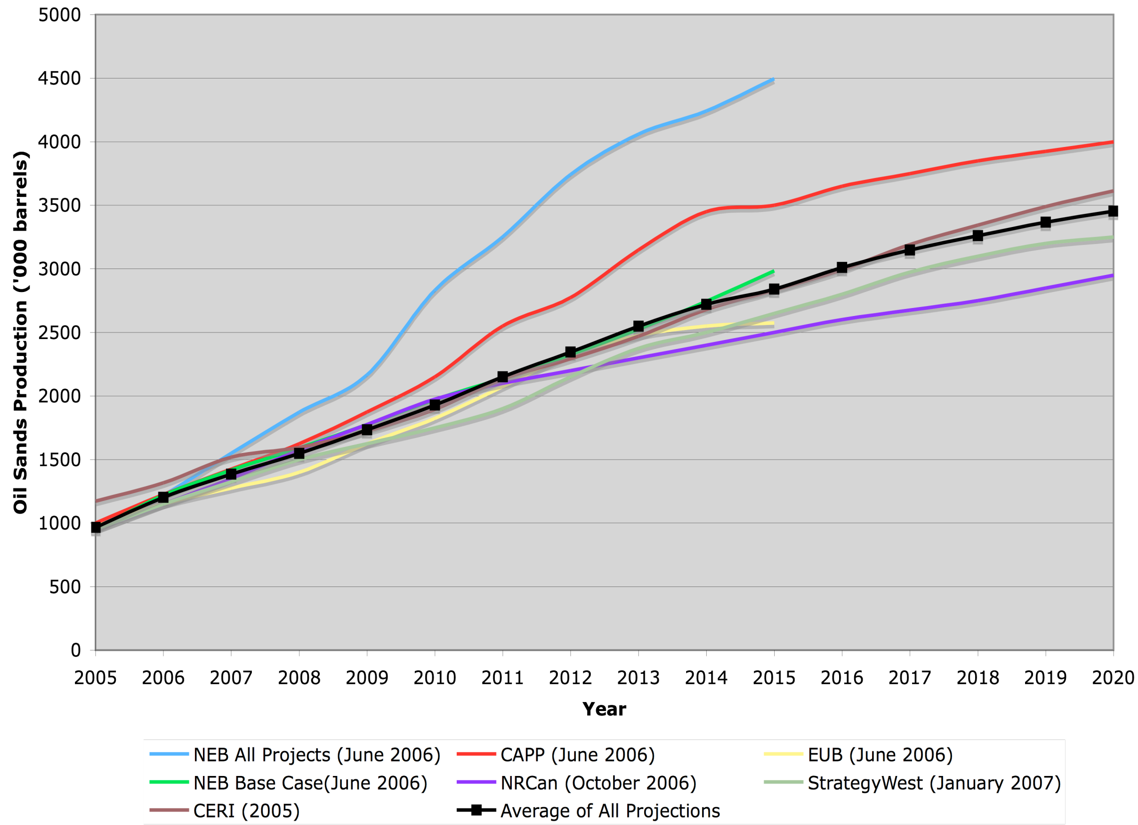


Figure 17. Selected Oil Sands Production Projections for 2005-2020. (Source: StrategyWest, NEB, CERI)

Figure 17 illustrates a selection of the most recent oil sands production projections that have been selected as either having a greater than average probability of accuracy or for their illustrative purposes. First, note the NEB all projects case, as of June 2006, that indicates in just a ten-year span, from 2005 to 2015, 3.5 million barrels per day of capacity could be added to oil sands production. This scenario is highly unlikely, but serves as the upper limit of production possibilities, as it does not account for any cumulative effects or changes in political or economic climate. Second, CAPP's bullish outlook on project and cost management could account for their high production projection. Third, the relatively tight cluster of the NEB, EUB, and Federal Ministry of Natural Resources Canada (NRCan) scenarios derive from ostensibly impartial evaluations of the industry and economic conditions. Fourth, note the Canadian Energy Research Institute (CERI) and StrategyWest scenarios, both of which are made by research and consulting organizations that track relatively near the average of all projections. While it is entirely possible that these projections will be as inaccurate as their predecessors, it is clear from the massive amount of investment that the oil sands industry will be growing rapidly for at least the coming decade. Reflecting his organization's optimism, Greg Stringham, vice president of CAPP, believes that "there is no price scenario that could derail the oil sands, be it oil prices or natural-gas prices."[58] Although this assessment may appear to be rather optimistic, industry does indeed believe that high labor, capital, commodity prices and the ensuing capital and construction costs may have stabilized. These costs will determine the future growth of the oil sands and will be discussed in Chapter 4.

The uncertainty of production forecasts makes predicting the environmental effects of oil sands development all the more difficult. It is clear, however, that the manufacturing of synthetic crude oil has a significant impact on the environment because of the intensity of natural gas and water inputs. These relationships are analyzed and summarized by Figure 18. It is important for the reader to note that as one scales up outputs per barrel by a factor of a million per day, these environmental issues become highly significant and may even threaten to limit the future growth of the oil sands.

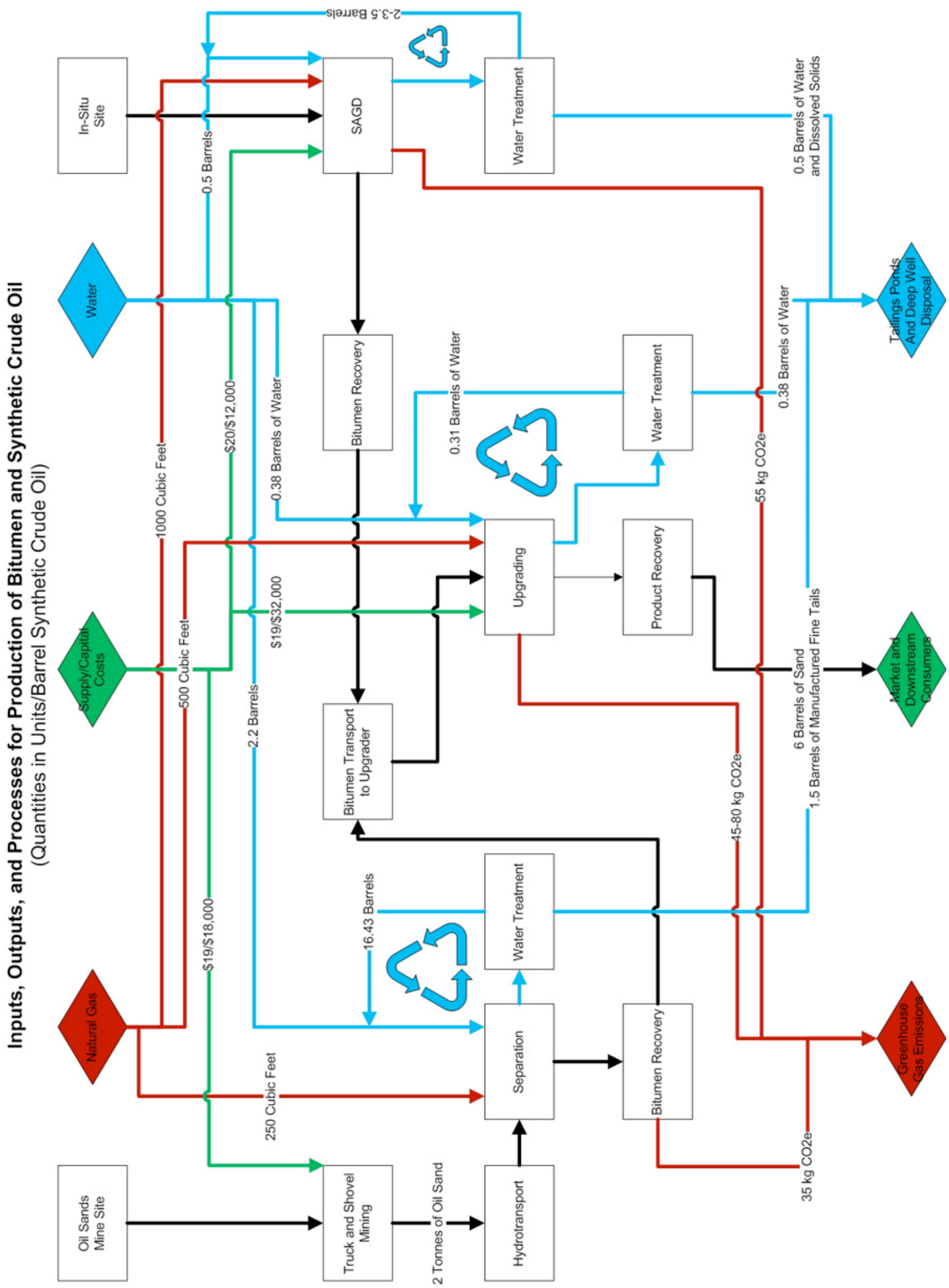


Figure 18. Inputs, Outputs, and Processes for Production of Bitumen and Synthetic Crude Oil.

Chapter 3: Environmental Issues

3.1 Introduction

As illustrated in Chapter 2, the rate of growth and the scale of oil sands development are causes for environmental concern. The National Energy Board (NEB) projects that production in the oil sands will double from 920,000 barrels per day in 2003 to 1.8 million barrels per day in 2010, putting the timing of this thesis in the middle of the current rapid development.[1] The production of bitumen and synthetic crude oil from the oil sands has a direct impact upon the quality of water, land, and air in the Fort McMurray region and is the subject of intense debate between industry, interest groups, the government, and the public.

As the oil sands emerge as a large source of Canada's oil production, the oil sands companies, the Canadian Association of Petroleum Producers, and the Pembina Institute have emerged as the leading contenders for influencing public opinion and possible provincial and federal government policies. In addition to these interested parties, several multi-stakeholder organizations of varying purpose and efficacy monitor and formulate potential policies for the environmental impact of the oil sands. These organizations include the Wood Buffalo Environmental Association (WBEA), the Cumulative Effects Management Association (CEMA), and the Regional Aquatic Monitoring Program (RAMP). With the withdrawal from CEMA of the Athabasca Chipewyan, a First Nations band that lives downstream of the oil sands facilities, the efficacy of the multi-stakeholder process is in question.[2] This is significant as much of Alberta's environmental legislation and regulation, such as the Water for Life province-wide water policy framework, is based on a consensus approach depending on the input of these stakeholders. Residents of the Wood Buffalo region, which includes Fort McMurray, have emerged as an increasingly vocal force in public hearings for regulatory approvals. Accordingly, the Alberta Energy and Utilities Board, which oversees plant construction licensing, has strengthened its recommendations to the province. In recent decisions, it has encouraged the government to take action in order to mitigate environmental, economic, and socioeconomic issues associated with the development of the oil sands industry.

Environmental effects can be divided into three geographic categories – local, regional, and national. Local-scale impacts occur on the oil sands leases themselves. These include water pollution and land reclamation. Regional impacts, such as air pollution, affect the municipality of Wood Buffalo, which encompasses the northeast corner of Alberta). The greenhouse gas emissions from the oil sands projects are national-scale issues with economic and political ramifications, and as such will be discussed at the end of this chapter as a segue into the analysis of economic issues in Chapter 4.

3.2 Impact on Water

Due to the large amount of process water required for the transport, separation, and production of bitumen, water issues are particularly important in the oil sands region. Water issues encompass three very different problems. The first, and arguably most important, is the confinement of tailings in large settling basins called tailings ponds. The second is the usage of surface water from the Athabasca River for mining projects. The third is the usage of water from underground aquifers for in-situ production.

Mining facilities use water withdrawn from the Athabasca River as slurry to transport oil sands and process water to separate bitumen from the sand. The effluent water is contaminated with hydrocarbons such as naphthenic acids and must be reprocessed. Even after reprocessing to scrub naphtha, some hydrocarbons remain, along with fine clay and silt particles. As the mining companies operate under a zero discharge policy, all process water consumed since the beginning of production must be stored on site in tailings ponds. These tailings ponds are removed from the natural hydrologic cycle and are contained by some of the largest dams in the world. The scale of these tailings ponds is somewhat unimaginable, as seen in the aerial photograph comparison in Chapter 1. Suncor's nine tailings ponds have a surface area of 22.8 square kilometers.[3] In contrast, the Mildred Lake Settling Basin, one of Syncrude's tailings ponds, alone has a surface area of 13 square kilometers and over 400 million cubic meters of fine tailings (see Figure 19).[4]

The potential environmental consequences of these tailings ponds have been of concern to environmental groups since the inception of the plants. Save Tomorrow, Oppose Pollution (STOP), an Edmonton-based environmental group, raised awareness in the late 1970s of the tailings ponds' toxic effects on migratory birds and the potential for pollutant release.[5] Because of contamination with hydrocarbon residue, oil sands companies use propane cannons and scarecrows known as Bitu-men to keep birds from landing on the tailings ponds. These tailings ponds are seen as a long-term environmental liability, as their reclamation has been met with mixed success, an issue that will be discussed later in this chapter.

Figure 19. Syncrude Tailings Ponds. The tailings pond at left is being converted to an end-pit lake, whereas the tailings pond at right is being reclaimed. Highway 63 (berm) leads from the reclamation project in the foreground to the plant in the distance. (MTW, 20 August 2006)

The tailings ponds are toxic partly because of the high concentration of naphthenic acids, which is due to the recycling of process water up to 18 times.[6] This recycling concentrates the naphthenic acids in the tailings ponds to levels as high as 110 milligrams per liter from a regional background level of one milligrams per liter.[7] These naphthenic acids have approximately the same dissociation constant as acetic acid, or vinegar. Naphthenic acids are natural surfactants, having a polar carboxyl tail at the end of the side chain and non-polar hydrocarbon rings.[8] Unfortunately, these hydrocarbon residues can only be broken down by methanogenic microbial action over a long period.[9] Laboratory tests conducted by the University of Alberta indicate that the bacteria in one milliliter of fine tailings produce 0.10 to 0.25 milliliters of methane at standard temperature and pressure, or 123 kilograms of methane per cubic meter of fine tailings water.[10] The growth of methanogenic bacteria, however, can be limited by the competition of sulfate-reducing bacteria, which feed on the gypsum added to increase the settling rate of tailings.[11] The scale of methanogenesis is of great concern, as methane is a greenhouse gas and represents approximately 60 to 80 percent of the gas exchange at the surface of tailings ponds.[12]

Figure 20. (Left) Suncor Tailings Pond. Note low-grade oil sand tailings deposits at left. (MTW, 20 August 2006)

(Right) Syncrude Tailings Pond East of Highway 63, undergoing reclamation. Note dust clouding on the horizon and piles of low-grade oil sands at right. (MTW, 19 August 2006)

Suspended clay particles in the tailings create turbidity and prevent aquatic life from establishing itself in the tailings ponds. These tailings coat fish gills and act as a surfactant, causing fish to suffocate.[13] Even after reclamation, wildlife struggles to survive, with rainbow trout devoid of their distinctive coloration and suffering from low, possibly negative, population growth.[14] Larger particles in the tailings settle out, but the settling time for the fine clay particles is estimated to be approximately a hundred years. Gypsum, a byproduct from oil sands processing, is used as a flocculant and added to manufactured fine tails to create composite tails. Composite tails settle faster, not only allowing water to be recycled back to the operating plant more rapidly but also contributing to the more rapid formation of a reclaimed landscape. Nevertheless, the composite tails that settle are still poorly consolidated and contain large amounts of water. As a result, the tailings deposited can be so soft that vibrations from vehicles traveling on the reclaimed landscape will cause the equipment to sink into the clay.[15] The mining companies, therefore, plan to cap some of the composite tailings deposits with a layer of fresh water to create an end-pit lake. According to research in test ponds, Syncrude has found that these end-pit lakes will take several years to evolve into natural

Figure 21. Syncrude Tailings Pond West of Highway 63, which will become an end pit lake. Note water treatment facility in midground and bucketwheel reclaimer in background. Dark mounds in foreground are low-grade oil sands. (MTW, 20 August 2006)

ecosystems even after reclamation is completed.[16] As an area of current research, tailings management will undoubtedly change. Paste technology, developed by Syncrude and the Canadian Oil Sands Network for Research and Development will produce a soft clay that can be either landfilled or immediately incorporated into a landscape.[17] It is hoped that better tailings management will lead to a decrease in the size of tailings ponds, and as such, decrease the enormity of the task of hydrologic reintegration.

In addition to the long-term liability of tailings ponds, the usage of water in the oil sands region is also of concern. As Alberta Environment states, the province "has roughly ten percent of Canada's population and seven percent of the land area, but only two percent of Canada's water supply."[18] Although the oil and gas industry has less than a tenth of the surface and groundwater allocations as those of agricultural irrigation (3.6 percent vs. 44.8 percent), the public sees the industrial consumption of water as a major issue.[19] Reflecting this fact, CAPP launched a series of television advertisements in October 2006 attempting to persuade the public that the petroleum industry's water usage is minimal.[20] While the industry may have financial incentives to minimize the intensity of water use, the fact remains that the current volume of water licenses for oil sands facilities are equivalent to the water needs of a city of three million people, or the roughly the entire population of Alberta.[21]

On the Athabasca River, existing and approved oil sands facilities are licensed to withdraw 349 million cubic meters of water annually, with an additional 140 million cubic meters of water licenses attached to planned projects. Alberta Environment monitors the flow rates of the Athabasca River. The ministry is in the first phase of a joint monitoring program with industrial users and environmental interest groups. This phase is designed to minimize the risk of habitat loss during low river flow. The intention is to keep habitat loss to less than 10 percent of the lowest river flow. Monitoring and research will provide data for periodic consultative reviews with a multi-stakeholder organization such as CEMA.[22] Defining, monitoring, and regulating water usage in the oil sands, however, will only become more complicated in coming years. Both Syncrude and Suncor are now operating satellite extraction facilities (Syncrude – Aurora – mining, Suncor – Firebag – SAGD) that receive their water from the base plant, which in turn extracts water from the Athabasca River.

As the Athabasca is a glacially fed river from the Columbia Icefields in the Rocky Mountains, the lowest flow rates occur in the mid-winter when runoff is minimal. As such, the low flow rate plus a growing rate of water extraction risks damaging aquatic habitat not only in the Fort McMurray region but also further downstream. The Athabasca River's delta is one of the most important migratory bird breeding grounds on the continent. It is particularly worrisome, therefore, that some First Nations elders have notice qualitative changes in the river. According to Elsie Fabian, an elder quoted in the *Washington Post*, "the river used to be blue. Now it's brown. Nobody can fish or drink from it. This has all happened so fast." Other communities have reported that northern pike, walleye, and burbot (a regional fish species) may have difficulty surviving the reduced midwinter low flow rates.[23] The Athabasca Chipewyan, who withdrew from CEMA in September 2006, cited a lack of progress in water issues, with an elder saying that "I don't think [the provincial government and industry] are serious about taking our advice." Greg Stringham, a vice-president at CAPP, responded that aboriginal membership in these organizations is "critical" and that industry and government would continue to investigate water issues, particularly the low-flow rates that concern the aboriginal groups.[24] Members of multi-stakeholder groups will need to resolve their differences in order to formulate regional plans that will guide the reduction of water usage by all facilities along the Athabasca River.

Oil sands mining companies have focused on reducing water usage by increasing the process water recycling. These efforts have centered on advancing dry tailings technologies, improving consolidated tailings technologies, and increasing settling rates.[25] Between 2000 and 2004, Suncor reduced its water intensity by over 30 percent from 6.2 barrels of water to 4.2 barrels of water per barrel of synthetic crude oil.[26] Currently, Syncrude has the lowest need for make-up water in the region as a result of plant retrofits and technology implementation. Syncrude uses 2.28 barrels of water per barrel of synthetic crude oil produced. This equates to approximately 4,000 cubic meters of fresh feed river water every hour, or 0.2 percent of the Athabasca River's average annual flow and 0.5 percent of the river's winter low flow.[27] With planned expansions, Syncrude estimates its water withdrawals will increase to 0.3 percent of average annual flow and 1 percent of the river's winter low flow.[28] The growth of existing operations and the development of new mining facilities will dramatically increase stress on the Athabasca River's ecosystem, particularly in mid-winter.

The growth of SAGD facilities across the Athabasca oil sands region has raised new concerns, as these operations are frequently far from large sources of surface water, and therefore must tap underground aquifers. The oil sand industry is licensed to use 75 million cubic meters of groundwater per year, but currently uses only 20 million cubic meters per year to extract and process oil sands.[29] Significant water withdrawals from both the draining of muskeg and pumping of groundwater may alter the water table and permanently damage the health of aquifers. As a result, with the projected growth in coming years, the industry has been actively pursuing ways to use saline aquifers. While avoiding the use of fresh groundwater aquifers is environmentally preferable, the depletion of deep saline aquifers may also be of concern as they take millennia to recharge. Therefore, in-situ oil sands operators are looking at a variety of technologies to maximize water recycling for SAGD extraction such as evaporators, zero liquid discharge crystallizers, or improved reverse osmosis filters.[30]

3.3 Impact on Land

Figure 22. Aerial Photograph of OPTI/Nexen Long Lake SAGD Facility. Note facility construction at left. Adobe Photoshop used to highlight 93 visible seismic features. Photograph is 1km x 1km. (Source: Google Earth)

The development of in-situ leases necessitates exploration and drilling over vast areas, affecting both the landscape and regional ecology. Seismic exploration, which is used to profile bitumen deposits underground, has historically required five-meter wide survey cut lines through the boreal forest. These survey lines leave long-lasting scars on the landscape that are easily visible from the air (see Figure 22). With improving technology, exploration can now be done with smaller 1.5-meter wide cut lines. Biologists are concerned that these survey lines lead to not only to habitat fragmentation, but also to increased access to predators. This affects native wildlife by increasing the area of disturbance and adding to stress on an already fragile ecosystem. According to Pembina:

> Woodland caribou is one of the species likely to be extirpated from regions subjected to SAGD development. Caribou declines across Alberta have been correlated with the level of industrial development within their ranges. In the past ten years, the East Side Athabasca River caribou herd, whose range overlaps much of the current SAGD development, has declined by almost 50 percent. Studies have shown that forests within 1 km of roads and well sites tend to be avoided by caribou and that roads further fragment caribou habitat by acting as barriers to movement. It is believed that this fragmentation concentrates woodland caribou into smaller portions of their range, where they become more susceptible to

predation by wolves.[31]

The impact of development upon the boreal forest ecosystem also affects the traditional lifestyles of the First Nations communities along the Athabasca River. Howard Lacorde, a Cree trapper, said in a *New York Times* interview, as he surveyed a Canadian Natural Resources Limited construction site, that "there are no moose, no rabbits, no squirrels anymore. The land is dead."[32] Albertans must decide whether the economic benefits of oil sands development outweigh the costs of temporary extinction in the Wood Buffalo region. As shown above, the disappearance of wildlife will lead to complicated issues of social justice, as First Nations members will no longer be able to partake in their traditional lifestyles.

The Alberta government, through the Alberta Chamber of Resources, has attempted to mitigate ecological impacts via integrated land management. This work, however, has been of limited success. A 2004 petroleum industry publication ironically acknowledged that "in northeastern Alberta between 1990 and 2002, the oil and gas industry cut more timber than the forest products industry."[33] While SAGD uses the latest drilling technology that allows many wells to be drilled from a single pad, thus reducing the footprint of the development, the land area of the bitumen resource still means that the extent of the disturbance is still large. Industry argues that these wells are only temporary, and therefore will have limited impacts with lifetimes of less than 40 years. Questions remain, however, whether the ecosystem will be able to recover. OPTI/Nexen wrote in their Long Lake SAGD project Environmental Impact Assessment (EIA) that "ecological thresholds have not yet been established regarding impacts to biodiversity as a result of fragmentation by development. Until thresholds have been defined, it is difficult to quantify effects of development on ecosystem function [and] the actual effects on overall biodiversity and ecosystem function are not known....” The OPTI/Nexen Long Lake project will one day cover 106 square kilometers of boreal forest, with 8.3 percent of land cleared for SAGD infrastructure (see Figure 23). This includes a one square kilometer central facility, 234 exploratory wells, 288 production wells, and 89 kilometers of access roads and a pipeline. As a result, 80 percent of the land in the project’s lease will be within 250 meters of an industrial feature.[34]

Figure 23. Aerial Photograph of OPTI/Nexen Long Lake Facility. Note central facility and SAGD well pads with pipelines and service roads. Photograph is 5km x 9km. (Source: Google Earth).

While in-situ facilities will have at least a half-century impact on regional ecology, reclaiming open-pit mining sites presents an even greater challenge in the long-term. Under Alberta law, all oil sands companies are responsible for reclamation and thus returning the lease to equivalent land capability. Equivalent land capability is defined as “the ability of the land to support various land uses after conservation and reclamation [that] is similar to the ability that existed prior to an activity being conducted on the land, but that the individual land uses will not necessarily be identical."[35] Alternative outcomes are also acceptable, as long as the "suite of utility" remains the same, meaning that grassland and forest could replace muskeg. Because of this clause, the post-reclamation landscape will have more uplands and open bodies of water than the pre-industrial landscape, which will have an unknown effect on regional ecology. Until the conditions of equivalent land capability and suite of utility are fulfilled, mining companies remain in possession of the land and they must reserve adequate funds and materials for reclamation.[36] According to the NEB,

> Alberta's Upstream Oil and Gas Reclamation and Remediation Program have expanded the scope of industry liability for reclaimed sites. The AEUB's Directive 001 outlines the requirements for a site-specific liability assessment, which is conducted by a licensee or approval holder, to estimate the cost to suspend, abandon, or reclaim a site.[37]

Oil sands companies are required to post a financial security that is equivalent to the cost of reclamation, which is reassessed and posted annually. This reclamation fund increases in value with additional land disturbance and decreases as reclamation work is completed. Upon completion of reclamation, a certificate is issued to lease holder, but so far, no reclamation sites have received such a certificate.[38]

The oil sands companies endeavor to reclaim the mines "as early as practical," and so reclamation occurs concurrently with mining.[39] Before the land surface is prepared for mining, biologists survey the area for particularly healthy sections of muskeg and topsoil, which will be removed and preserved in storage. The topsoil segments contain native plant materials that will germinate when placed into a final reclaimed landscape. At the end of mining, a vast open pit remains, which is usually converted into a tailings pond. As tailings consolidate at the bottom, the open pit is

Figure 24. Panorama of Suncor's Reclaimed and Unreclaimed Landscape from Syncrude's Matcheetawin Discovery Trails. At left, note coke piles and tailings pond. At right, note reclaimed area, approximately two decades old. In midground, note highway construction. (MTW, 20 August 2006)

gradually filled in with material. Overburden, removed from current mining preparation areas, is used to create the post-reclamation landform and cap the tailings deposit. The overburden is covered with topsoil in order "to provide sufficient moisture storage for vegetation while minimizing runoff and salt transport into the cover from the underlying overburden."[40] A starter crop such as barley is planted to establish a pioneer ecosystem in the finished reclaimed area. Trees and vegetation are then seeded and the final terrain is shaped in order to minimize erosion. University of Alberta researchers have found that the growth of native tree species is adversely affected by mineral-laced tailings water and that needle necrosis was positively correlated to tissue levels of Na and Cl.[41] Therefore, salinity of soil and water is of concern for the sustainability of the reclamation. In a similar study, fine tailings (15 percent) mixed with topsoil (85 percent) delayed the germination of dogwood and jack pine seeds, but not white spruce. Likewise, survival rates after 6 months for raspberry were reduced to 44 percent, for jack pine to 55 percent, and for white spruce to 94 percent.[42] Therefore, fine tailings have an unequal and uncertain effect upon the growth of certain reclamation species. The impact of the reclaimed landscape extends beyond flora to reintroduced fauna. A Simon Fraser University study found that mallard ducklings raised on oil-sands based wetlands had significantly lower body mass and skeletal size than their control counterparts raised on a natural wetland in northern Alberta.[43] Some areas of the reclamation are outfitted with monitoring instruments to evaluate the efficacy of reclamation, with particular interest in reestablishing a sustainable surface and underground hydrology. Researchers at both Syncrude and the University of Saskatchewan are developing a system dynamics watershed model to simulate the sustainability of reclaimed watersheds. This will prove an invaluable step in the eventual government certification that these landscapes are officially reclaimed.[44]

The mining reclamation task is proceeding at an increasing rate, but it is still an undertaking of unprecedented scope. As of 2004, Suncor had reclaimed only 9 percent of its total land disturbed, whereas Syncrude has reclaimed approximately 18 percent of its Mildred Lake mine site.[45] Syncrude expects 25 percent of the reclamation will remain after mining ceases, which could lead to asset retirement issues, as funds for this reclamation will need to be secured before the end of mining.[46] In total, the mining companies have reclaimed approximately 15 percent of the land area disturbed, for a total of 53.6 square kilometers.[47] The final reclamation is expected to cost approximately $1.8 billion, which is approximately $0.35 per barrel. This figure, is in doubt, though, as an additional 950 square kilometers have been approved for development over the next several decades (see Figure 25).[48] With such a mammoth task ahead, the present time is an ideal opportunity for the provincial government to formulate a comprehensive regional strategy for reclamation.

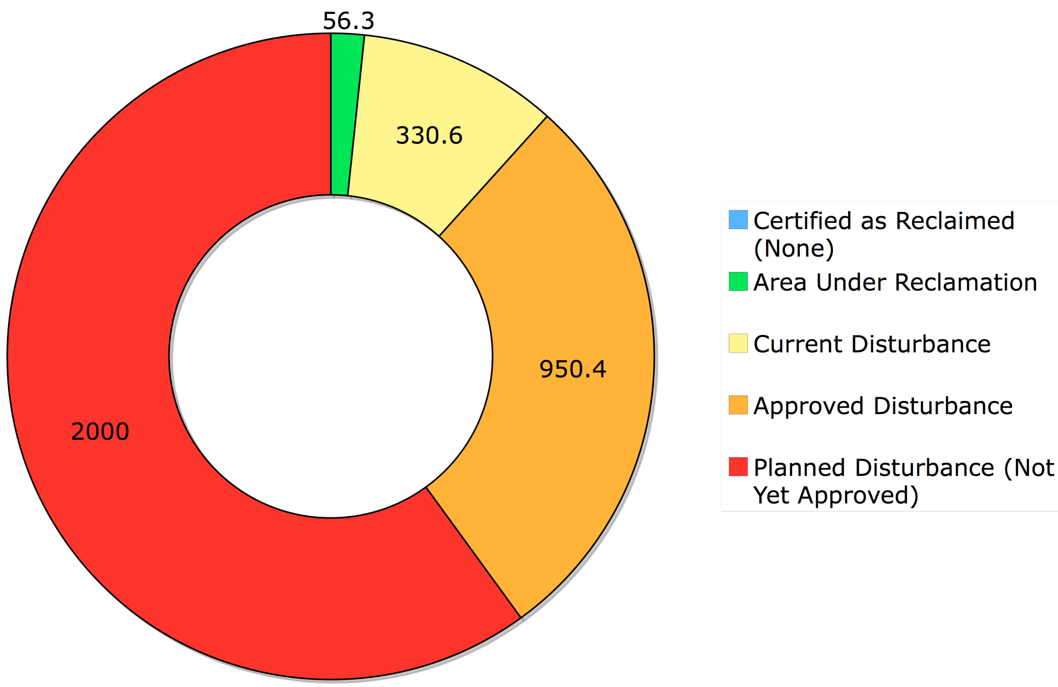


Figure 25. Land Disturbance and Reclamation in the Athabasca Oil Sands Region. Land areas in square kilometers. Note none of the land is certified as reclaimed. (Source: Pembina)

As reclamation is such a public concern and a significant investment, the oil sands companies are keen to improve their environmental image. Syncrude opened the Wood Bison Trail in 1995 as a welcome center, which straddles Highway 63 on its approach to the mine and plant site (see Figure 26). On the east side of the highway is a pair of recreational trails – the Matcheetawin (Cree for "beginning place") and the Sagow Pematosowin Discovery Trails (Cree for "living in peaceful co-existence with the land").[49] On these four kilometers of trails, one can hike along the reclaimed benches of the former open-pit mine and see the 0.5 square kilometer two-decade-old forest, which in August 2006 had little observable wildlife, consisting of only chipmunks and birds of prey. The reclaimed landscape consists of white spruce, green alder, aspen poplar, jack pine, saskatoonberry, Siberian larch, red osier dogwood, grasslands and wetlands. Outlooks along the way provide panoramic views of the Syncrude and Suncor leases. On

Figure 26. Photographs of Reclamation along Syncrude's Matcheetawin Discovery Trails. This is characteristic of early reclamation efforts planted in the early 1980s. (Left) Note erosion-resistant artificial drainage swale into wetland. Suncor's reclamation in distance. (MTW, 20 August 2006)

(Right) Note terrain still shows former mining benches. (MTW, 20 August 2006)

the west side of the highway, visitors can stop at the Wood Bison viewpoint. A series of rolling hills and patchy forestation camouflages over 300 wood bison from view. The wood bison were "chosen as a focus [of the reclamation projects] because the species was native to the area until their near extinction in the 1800s, and played an important role in the economy and culture of Aboriginal communities."[50] Syncrude accrues two benefits from placing wood bison in a new habitat, which is completely incongruous with the surrounding muskeg. First, Syncrude and the local First Nations have ostensibly created a sustainable industry that will be based on bison ranching. Second, Syncrude undoubtedly benefits from the public relations image of charismatic megafauna, a large animal such as the wood bison with which the public can associate the reclamation project.

Another reclamation challenge will be the large amounts of sulfur stockpiled on Syncrude's site, a byproduct from the production of bitumen and synthetic crude oil (see Figure 27). Sulfur, which is sold to fertilizer and petrochemical companies, if possible, is stored up due to an oversupply of elemental sulfur on the world market. [51] These piles

Figure 27. Stockpiled Sulfur on Syncrude's Plant Site. Note excavator in foreground for approximate scale. (MTW, 19 August 2006)

produce acidic runoff, which must be neutralized and isolated from the surrounding soil in order to minimize heavy metal liberation and pollution of groundwater.[52] Marsulex, a Canada-based sulfur products company, has built a $44 million plant to process sulfur in order to make a projected 80,000 to 100,000 tons of fertilizer per year.[53] This in turn should reduce stockpiles and add value to the waste products from bitumen processing. The National Energy Board predicted in 2004 that by 2030, oil sands companies may produce more than 10 million tons of sulfur annually.[54] Even though the stockpiling of sulfur helps to reduce air emissions, it also creates the potential for significant impacts on the land. The sulfur piles, acidic water, and sulfur dioxide emissions are an excellent example for demonstrating the interconnected issues of the land, water, and air in the oil sands region.

3.4 Impact on Air

Air pollution has long been recognized as a major consequence of oil sands production, with Save Tomorrow, Oppose Pollution (STOP), an Edmonton-based environmental group, campaigning in the late 1970s to have Syncrude reduce its sulfur dioxide emissions.[55] While much of this initial concern was most likely over the effect of acidifying emissions on relatively undisturbed boreal forests, today there are additional concerns because of the oil sands rate of growth. The oil sands industry is a large source

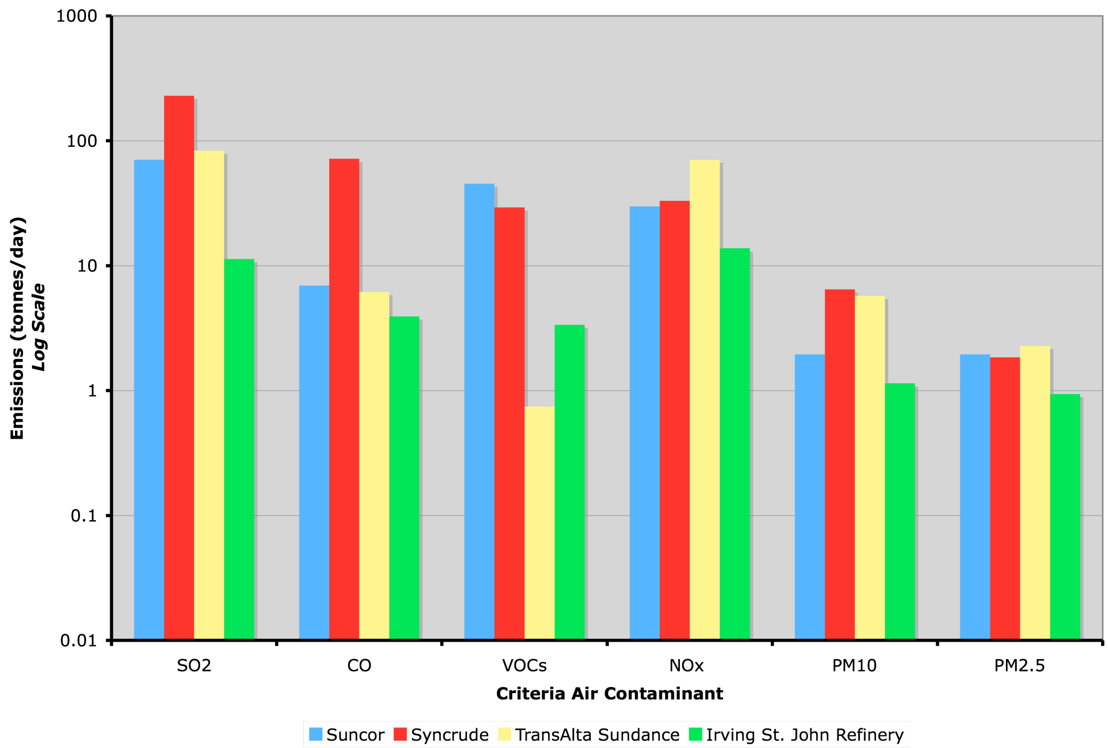


Figure 28. Comparison of 2005 Criteria Air Contaminant Emissions. TransAlta Sundance (Alberta) is the largest coal-fired generating facility in western Canada with a 2020MW capacity, providing electricity for two million homes. Irving St. John Refinery (Newfoundland) is the largest refinery in Canada, with a capacity of 300,000 barrels/day. Note that the oil sands facilities produce comparable amounts of SO2 and NOx emissions to a large power plant. In addition, oil sands facilities produce more VOCs than the comparison facilities, largely because of their tailings ponds. (Source: NPRI, PollutionWatch.org)

of criteria air contaminants, both in Alberta and in Canada (see Figure 28). Criteria air contaminants such as sulfur oxides (SOx), nitrogen oxides (NOx), particulate matter (PM), and volatile organic compounds (VOCs), lead to environmental and health hazards such as acidifying precipitation and tropospheric ozone. In 2003, Syncrude reported the largest combined criteria air contaminant emissions of any facility in Alberta.[56]

Acidifying emissions in the oil sands region, therefore, are still of great concern, despite industry claims that the alkaline soils of the region act as a natural buffer to an ecological damage.[57] These claims are contradicted by OPTI/Nexen's admission in their Long Lake Environmental Impact Assessment that the resulting acidification in some regional lakes may affect amphibian embryos, which are generally considered a bellwether for environmental impacts.[58] While emissions per barrel have decreased, the dramatic increase in production in the past few years, along with the projected production increases have offset most environmental gains. The single counterexample to this trend is that absolute sulfur dioxide emissions have stabilized in recent years because of technological advances in the separation processes and the use of effluent stack scrubbing equipment. Between the early 1990s and 2004, emissions of sulfur dioxide by the oil sands industry fell by about one-third.[59] In 2005, Syncrude emitted 227 tons of sulfur dioxide per day, or a little over one kilogram of SO_2 per barrel of synthetic crude oil produced.[60] Syncrude's emissions per barrel, however, are set to decrease by 60 percent by 2012 due to the implementation of a new Flue Gas Desulphurization Unit.[61] An upset at this unit in May 2006, caused the escape of ammonia gas. This incident caused eye irritation and complaints of a "cat urine" odor 40 kilometers away in Fort McMurray. As a result, Syncrude was forced to reschedule the ribbon-cutting ceremony for the company's $7.4 billion expansion that included the new desulfurization unit.[62]

In recent years, nitrogen oxide emissions from oil sands facilities have grown dramatically with increased production, surpassing those from Edmonton in 2003. This growth will continue, with Alberta Environment projecting that the NOx emissions will exceed those of Calgary in three years time (see Figure 29).[63] In 2005, Syncrude emitted 55 tons per day of NOx, resulting in 0.25 kilograms produced per barrel of synthetic crude oil.[64] This dramatic increase in the production of NOx not only has ramifications as an acidifying emission, but when combined with aerosolized hydrocarbons (VOCs), NOx can form tropospheric, or ground level, ozone. Three-quarters of Wood Buffalo's current VOC emissions come from tailings ponds.[65] These emissions are projected to nearly double between 2005 and 2010, rising to 945 tons per day in 2010, compared to 364 tons per day from Edmonton and 619 tons per day from Calgary.[66] As the oil sands region is surrounded by coniferous forests (which provide an abundant supply of non-anthropogenic VOCs), the region's ozone production is most likely NOx limited, which means that any additional emissions of NOx will directly contribute to more ozone production. This relationship yields in interesting environmental policy result. Rather than attempting to control VOC emissions from tailings ponds, Alberta Environment should endeavor to control NOx pollution stringently in order to avoid degradations in regional air quality.

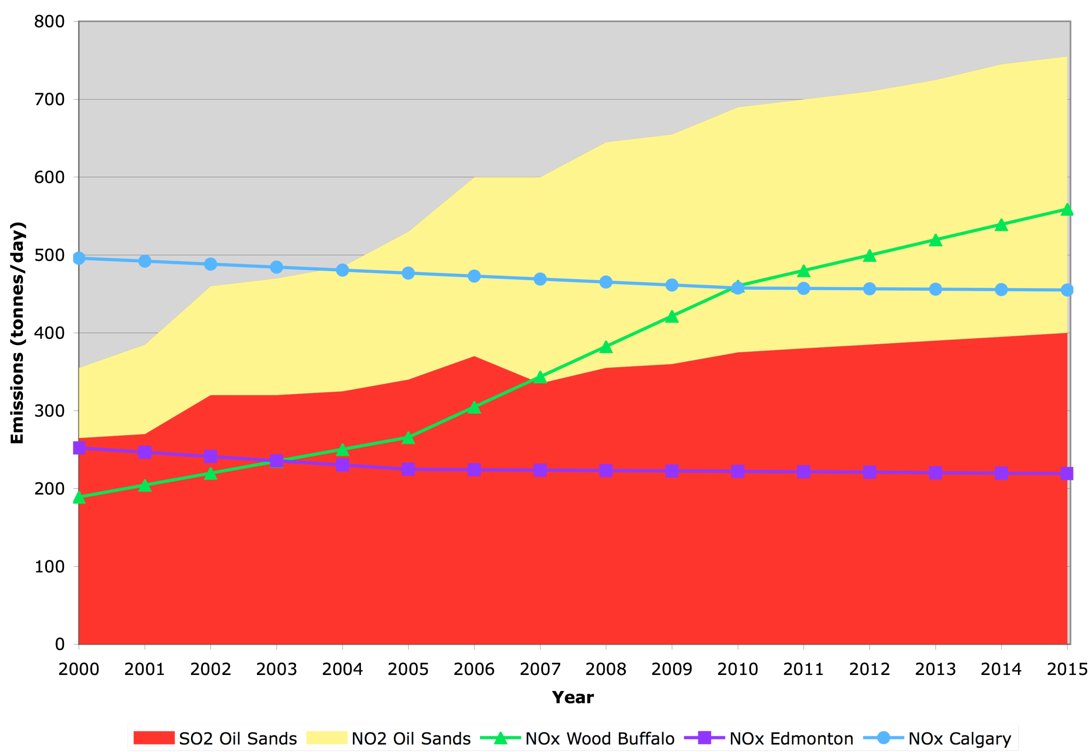


Figure 29. Acidifying Emissions Comparison for Oil Sands and Metro Areas of Alberta (2000-2015). Note the rapid rate of increase in NOx emissions in Wood Buffalo as compared to slight declines in NOx emissions for both Calgary and Edmonton. (Source: RWDI, CEMA)

3.5 Impact on Greenhouse Gas Emissions

Perhaps the most prominent and contentious oil sands environmental issue is the industry's emissions of greenhouse gasses. Due to the energy requirements for bitumen separation and synthetic crude oil production, the oil sands generate large, and rapidly growing, amounts of carbon dioxide. Greenhouse gas projections for individual projects and the entire oil sands industry are based on projected production amounts (as illustrated in Chapter 2) and greenhouse gas emission intensities. These intensities furthermore depend not only on the extraction technology used by the project but also on the fuel used to provide energy for extraction. The Pembina Institute estimates that mining of bitumen produces 35 kilograms of carbon dioxide equivalent per barrel, SAGD produces 55 kilograms of carbon dioxide equivalent (CO_2e) per barrel of bitumen, and upgrading of bitumen produces 45 kilograms CO_2e per barrel of bitumen. Switching fuels to petroleum coke and asphaltene residue (bitumen extraction waste products) may lead to even greater greenhouse gas intensities unless costly and capital-intensive mitigation strategies such as sequestration are adopted. Future in-situ extraction technologies may make the high intensity of greenhouse gas emissions from SAGD seem relatively low, with VAPEX producing an indeterminate amount of greenhouse gas emissions and THAI producing approximately 65 kilograms CO_2e per barrel of bitumen.[67] When compared to average North American crude oil imports, production of synthetic crude from the oil sands is 140 percent more greenhouse gas intensive from extraction to the downstream distribution network. Considering greenhouse gas emissions from initial extraction to end product consumption (which includes the middle steps of transportation and

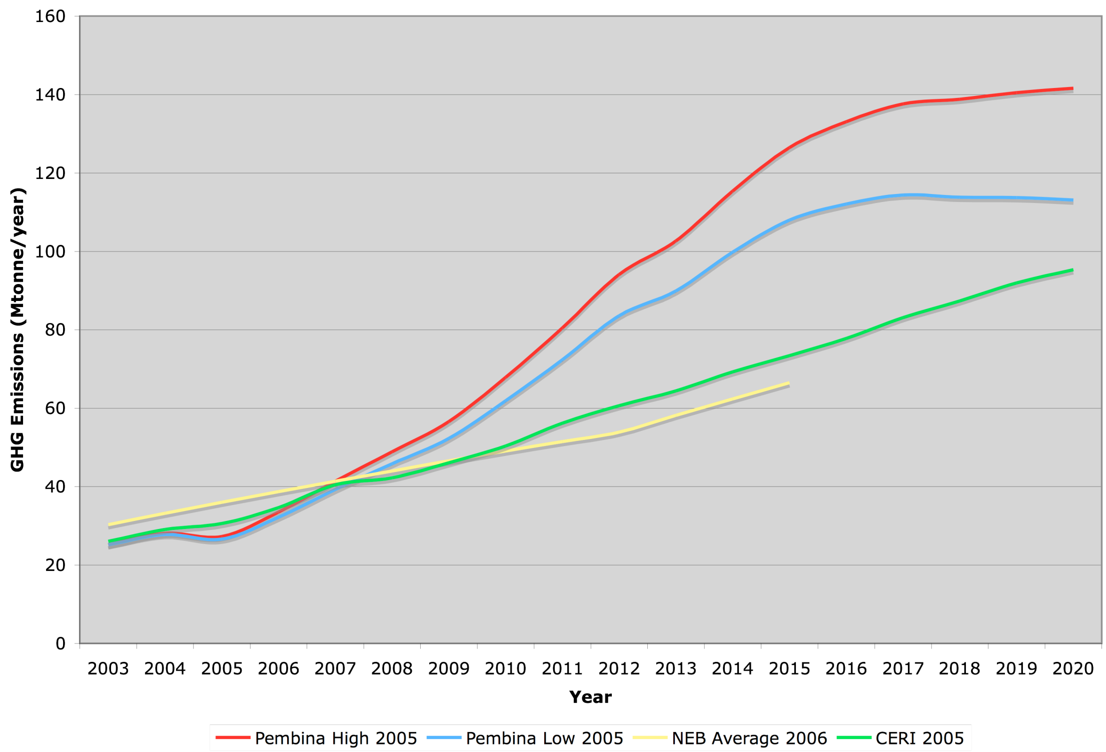


Figure 30. Comparison of GHG Emissions Projections. (Source: Pembina, NEB, CERI).

refining), however, the oil sands are only 7 percent more greenhouse gas intensive.[68]

Due to market competition, the oil sands industry has a strong financial incentive to reduce operating costs, and energy costs are a significant part of these operating expenditures. Reducing energy usage through process efficiency improvements can lower these costs. The average annual reduction in carbon dioxide emissions per barrel between 1988 and 2012 is expected to be 1.7 percent.[69] Despite these efforts, the fact remains that the oil sands are highly greenhouse gas intensive. With rapidly increasing production, the oil sands are the "elephant in the room" for any provincial, federal, or international climate change regulation.[70] A report issued by the federal Auditor General in fall 2006 noted that the oil industry, including the oil sands, has accounted for almost a third of the increase in Canada's greenhouse gas emissions since 1990.[71] Pembina's projections estimate that greenhouse gas emissions from the oil sands will rise to approximately 7.8 percent of Canada's 830 million tons of CO_2e business-as-usual scenario in 2010 from only 3.4 percent in 2003. In other terms, the oil sands greenhouse gas emissions will represent approximately 11.5 percent of Canada's annual average 2012 Kyoto target emissions of 560 million tons CO_2e. In total, the oil sands may contribute approximately 45 percent of projected business-as-usual growth from 2003 to 2010.[72] While these projections and therefore percentages appear to be at the upper end of how development may proceed, this clearly demonstrates that the growth of the oil sands is a major source of growth for greenhouse gas emissions (see Figure 30).

Now that Canada appears to have abandoned its former Kyoto Protocol obligations, Pembina's percentage are no longer useful for formulating policy, but are indicative of the significant greenhouse gas challenge facing the oil sands. When Kyoto was being considered in late 2002, the oil sands industry was concerned about the potential cost of compliance with Kyoto if the federal government ratified the treaty. With claims from industry that costs would bankrupt firms and that future projects would be cancelled and existing facilities rendered uneconomic because of Kyoto, it is unsurprising that over 70 percent of Albertans opposed Kyoto, whereas a majority of Canadians supported the protocol.[73] Predictions of dire consequences faded when Suncor announced specific compliance costs based on the price of offsets. These costs only amounted to \$0.15 to \$0.21 per barrel, and other companies eventually released estimates of \$0.12 per barrel up to \$0.26 per barrel.[74] Industry's concern over the cost of environmental regulation were unfounded, especially as if the market changes its price for oil by at least ±\$1 per barrel per day, an additional \$0.25 per barrel regulatory cost with certainty should be more than feasible.[75] As Alberta and Canada reconsider their policies towards oil sands development, policy makers and the public should keep in mind the historical precedent of dubious predictions of economic disaster.

3.6 Summary and Analysis

As examined in this chapter, the environmental degradation caused by the development of the Athabasca oil sands is inextricably linked to production. The key to reducing environmental impacts will be encouraging producers to adopt new, more efficient technologies through either regulations or market incentives. Three major environmental challenges currently face oil sands development. First, the cumulative environmental impacts of the oil sands development will occur across almost a quarter of the province. Second, the scale of the tailings ponds has generated great concern over their future reclamation. Third, and perhaps most importantly for both Alberta and Canada, the potential regulation of greenhouse gas emissions will undoubtedly affect future plans for projected growth in the oil sands.

First, the rapid growth of in-situ projects has the potential to affect the entire region's ecology. Pembina projects that if all the in-situ reserves are developed, the land area of disturbance will be 138,000 square kilometers, which equals 21 percent of Alberta's land area, and is equivalent to the size of Florida. Although this is a worst-case scenario, even if the total area of land already established for in-situ development as of July 2005 were to proceed, 36,000 square kilometers of land would be affected. If this area is "subjected to the same industrial footprint as the Long Lake project, then [2,960 square kilometers] of forest will be cleared for SAGD infrastructure and over 30,000 km of access roads will be built."[76] It is hard to imagine a situation where the Albertan or

Canadian public would tolerate development on this scale, but with no regional landscape plan in place, there are no standards by which to judge cumulative ecological impacts.

Second, while both water recycling technology and composite tailings technology have improved in recent years, the mining facilities will continue to produce tailings far into the future on a massive scale, with Pembina estimating that the "tailings produced by Suncor and Syncrude alone will exceed one billion cubic [meters] by the year 2020."[77] This will pose problems not only for the sustainability of the end pit lakes, but also the establishment of viable post-reclamation ecosystems. Over the past few years, both environmental groups and the provincial government have become increasingly

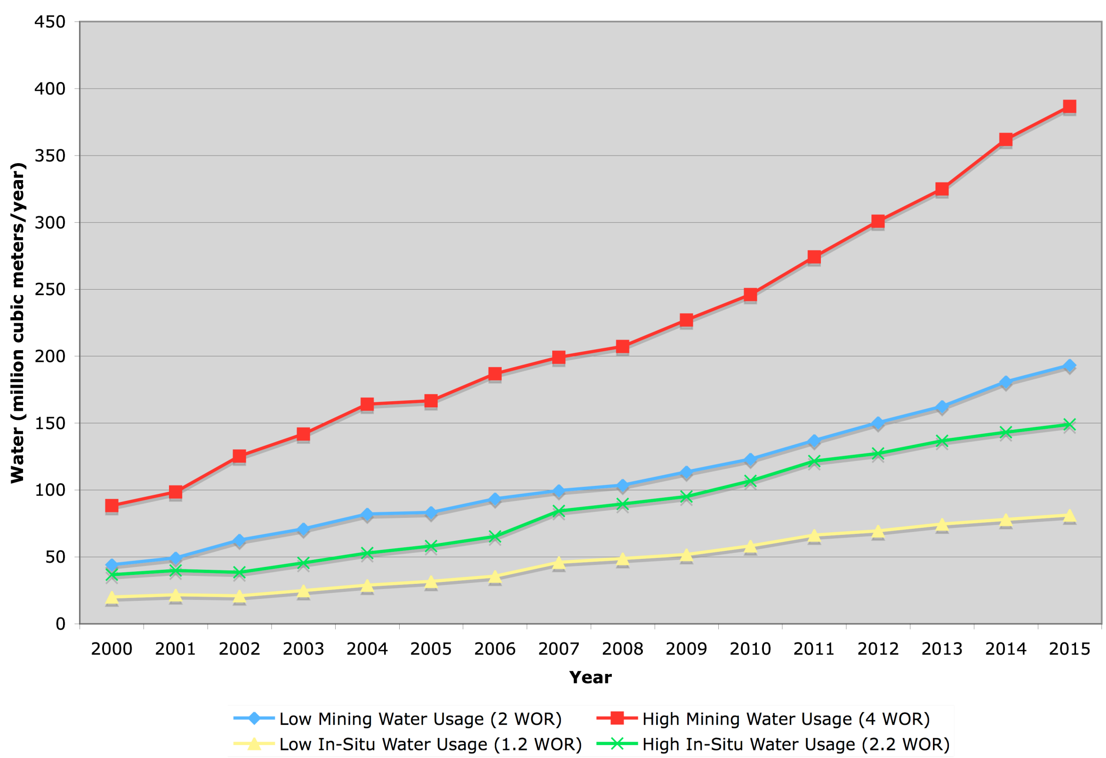


Figure 31. Comparison of Water Requirement Projections. There exist no accurate projections for oil sands water usage in the public domain. Projections formulated using CERI production numbers and labelled Water-to-Oil Ratios (barrels of water to produce a barrel of synthetic crude oil). As the usage of water in the oil sands is intimately linked with project economics, Alberta Environment is seeing much more rapid maturation around water use than in other industries.* [*]

interested in the cumulative impacts of the oil sands development and their effect on regional hydrology. Despite this concern there are no accurate projections of water usage for the oil sands industry in the public domain (see Figure 31). Without these projections, it is impossible to formulate appropriate water policies. The need for a comprehensive, preventative, and enforceable water policy is particularly urgent as the Athabasca River is glacially fed from the Columbia Icefields in the Rocky Mountains. According to climate change projections, the oil sands region is expected to experience above average warming, with the minimum flows of the Athabasca River decreasing 7-10 percent, exerting further pressure on aquatic ecosystems during the winter low-flow rate.[78]

Third, as global warming and climate change are an increasingly accepted part of the global energy conscience, the rapid growth in oil sands production is of particular concern to all Canadians. The importance of this issue cannot be understated, as the federal government is considering programs such as Kyoto or an equivalent Made-in-Canada approach that will establish a regime that is supposed to not only reduce emissions intensity but also reduce absolute emissions. In part due to its energy-intensive economy, Alberta has the highest greenhouse gas emissions of any province, emitting both the greatest amount of carbon dioxide and greatest amount of methane. The oil sands industry is the second ranked Canadian industrial sector for total greenhouse gas emissions, methane emissions, and carbon dioxide emissions, (behind the power industry, pipeline industry, and power industry respectively).[79] Within Alberta, Syncrude and Suncor are the second and third largest single-facility emitters of greenhouse gases, respectively.[80] Therefore, if existing oil sands projects are already some of the largest greenhouse gas emitting projects in Canada, it is understandable that industry, environmental groups, the federal government in Ottawa, and the provincial government in Edmonton are concerned about the consequences of production increases.

Although Alberta enacted its own Climate Change Action Plan in 2002, it encountered delays with setting targets, which are now to be released in the spring of 2007.[81] Alberta's 2002 climate change plan was designed "to reduce Alberta's greenhouse gas emissions intensity by fifty per cent below 1990 levels by the year 2020", but to date Alberta has only achieved an emissions intensity reduction of 15 percent.[82] Alberta industry currently emits approximately 110 million tons of CO_2e annually, with roughly 130 million tons CO_2e per year coming from non-industrial sectors. With the oil sands development, approximately another 100 million tons is expected to come from planned projects, possibly increasing Alberta's greenhouse gas emissions from 40 percent of Canada's total emissions to 50 to 60 percent in the coming decades. As part of their EUB approvals, oil sands operators have been required to publish annually their greenhouse gas intensities and compare these statistics to the projections in their environmental impact assessments. While this is intended to maintain accurate projections and enhance industry oversight, the industry has not filed such a report yet. In fact, despite having the first legislated climate change regulations in Canada and the first comprehensive regulations in North America, only one facility is regulated for greenhouse gas emission in Alberta.[83]

Alberta has made it clear that it opposes any and all federal intervention with regards to climate change. A spokesman for Alberta Environment, said in 2005 that "While the federal regulation of [greenhouse gases] may be appropriate or even supported by provinces in some parts of the country, Alberta legislation – not federal regulation – will be what regulates [greenhouse gases] in this province."[84] Mitigating greenhouse gas emissions during rapid and expansive oil sands development is a major challenge, especially as industry is wary of the additional compliance costs. Despite some oil and gas industry members preferring not to make environmental projections, not all companies are averse to announcing public targets.[85] Shell Canada is aiming for a greenhouse gas emissions intensity reduction of 50 percent from its business-as-usual scenario.[86] The CEO of Shell, Jeroen van der Veer, commented that "the debate about CO2 is changing…you can either fight it – which is useless – or you can see it as a business opportunity."[87] The business opportunities for greenhouse gas emission reductions will be discussed in both Chapters 4 and 6.

Chapter 4: Economics of Oil Sands Development

Investment in and revenue from the oil sands is a major driver of economic growth in Alberta. This chapter of the thesis will analyze how this investment is determined, why investors are willing to tolerate the high costs of development, why these high costs will continue to increase, how these costs are structured, and how these economic factors will determine the export of synthetic crude oil from the oil sands. It is important to understand the economics of non-renewable natural resources and how the development of oil resources is determined by supply and demand. The price dictated by this relationship dictates potential returns on the project, and thus influences the amount of investment. In turn, this investment builds and purchases the capital equipment and other inputs that sustain and grow production. The cost of capital equipment and other inputs, however, vary significantly for each project. These production costs will also greatly influence in what manner the bitumen and synthetic crude oil get to market. The economic analysis in this chapter will then expand into an investigation into the consequences of the growth of the oil sands in Chapter 5.

4.1. Natural Resource Economics

The demand for gasoline and other petroleum products heavily influences the exploration and production of crude oil. Historically, as economies expand, populations grow, and living standards increase, the demand for oil increases. Increased demand places an upward pressure on oil prices, thereby encouraging oil producers to increase the supply of oil to the market. This demand-generated price pressure prompts both the expansion of production from existing resources and the discovery of new reserves. Therefore, over time, the crude oil reserve base has grown to include resources that

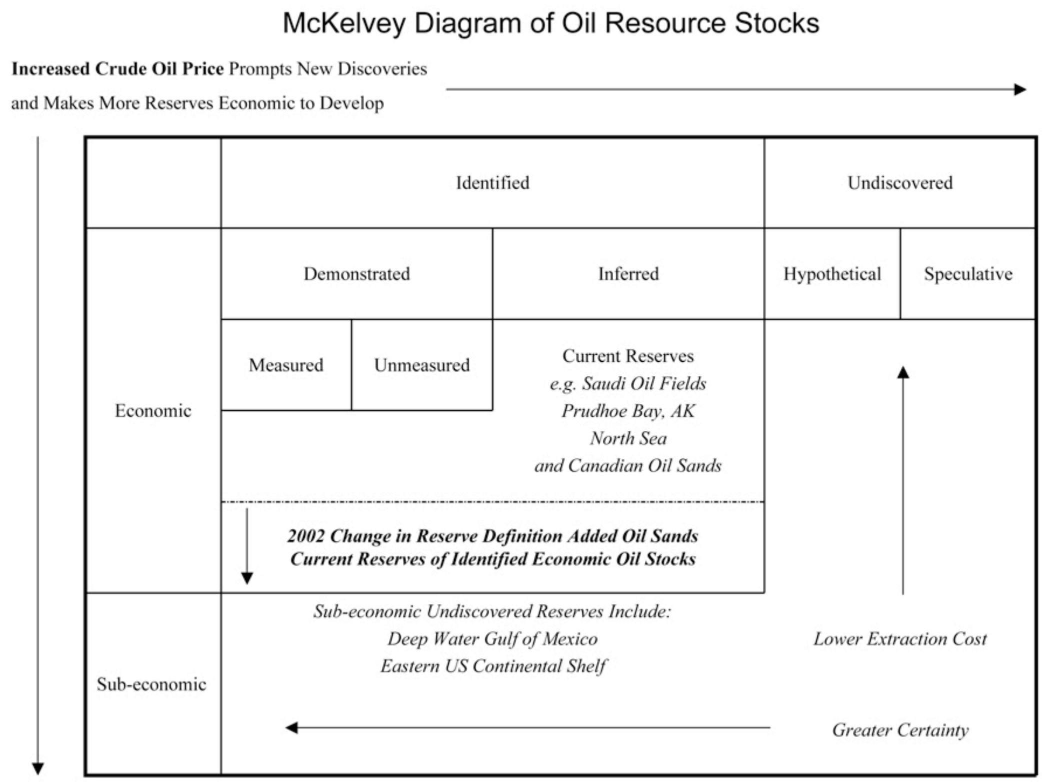


Figure 32. McKelvey Diagram of Oil Resource Stocks. Note the expansion of identified economic resource. (Source: Stavins)

require more technology to extract profitably such as offshore developments and the oil sands. In 2002, world crude reserves expanded dramatically, as *Oil and Gas Journal,* and later the U.S. Energy Information Agency, changed its accounting of Canadian reserves to include the oil sands as an identified, economic, and recoverable resource.[1] These trends and definitions are represented in the McKelvey Diagram of Oil Resource Stocks (see Figure 32). Although the production of synthetic crude oil from the oil sands appears to be economic for at least the short-term, the risk of market prices dipping below operating costs is higher for oil sands producers than that for firms who produce conventional crude oil. Even if the market price of oil is held constant, an increase in oil sands operating costs, like that of recent years, decreases profits for firms and increases risks. Despite the economic risks of developing the oil sands, high oil prices, market speculation, and political encouragement have prompted a surge of investment in the oil sands industry.

While the market price of crude oil fluctuates dramatically depending upon a variety of factors from seasonal demand (summer driving season) to geopolitical threats (potential reductions in Middle East supply), the price of oil without speculation is based upon non-renewable natural resource economics. The price of oil is the sum of the marginal extraction cost (the price to get the oil to market) and the marginal user cost, or resource scarcity rent. This compensatory rent is, in other terms, "the difference between the value of a resource and the cost of producing that resource, including a normal rate of return on investment. It represents the revenue that is available for capture by the owners of the resources for their development."[2] In the oil sands, the developers of the resource are the oil companies and the owner of the resource is the Alberta government, representing the citizens of Alberta. These two parties, therefore, split the rent in the form of profits and provincial royalties. As the oil sands industry is an oil price taker, reductions in marginal extraction costs due to improved technology increase the economic rent, therefore creating a profit incentive for firms to increase production. International oil companies will determine their investment in the oil sands based on the size of this economic rent as compared to alternative global energy investment opportunities, as well as supply costs, transport costs, ability to access downstream product markets, and macroeconomic conditions in Canada.

4.2. Developing the Oil Sands as Compared to Other Resources

As would be expected, oil sands industry producers and the Alberta Government are eager to establish their presence as a major player in global energy markets. In 2003, the International Energy Agency predicted that $3.1 trillion will be invested in the global oil industry between 2001 and 2030, with 3% of this or $92 billion, going to the development of oil sands and heavy oil in Canada and Venezuela.[3] While rising oil and commodity prices have already led companies to revise their investment strategies and in so doing made this prediction too conservative, it provides a rough estimate for how oil producing companies and governments plan on allocating their financial investments. The prospect of investing in a well-established oil-producing region that has been extensively explored and exists in a stable political and economic climate has lured many oil companies to invest in the Athabasca oil sands, despite the fact that it is relatively expensive to produce synthetic crude oil in Alberta compared to other places in the world. According to Simmons & Co., an energy investment firm, oil can be produced in Saudi Arabia for $10 per barrel, North Sea fields and existing oil sands facilities for $25 per barrel, Venezuelan heavy oil from $25 to $30 per barrel, and ethanol plants and new oil sands facilities for $50 per barrel.[4] Saudi Arabia indicated in January 2007 that $50 to $55 would be a 'fair price' for oil, giving an estimate of which of these projects might be economical for the near future.[5] Although Saudi Arabia is not a price maker for world oil markets, it does wield considerable influence to the extent that firms will use this announcement as a baseline for production and investment decisions. The implications for oil sands development are immense, as existing operations would be able to receive approximately half of their revenue as profit, whereas new facilities would be hardly able to cover costs. Therefore, the risks of entering the oil sands industry are very high, but the potential duration of production (due to the large bitumen resource) and its location in a stable geopolitical environment may mitigate some of these risks.

With the mitigation of geopolitical risks in mind, it is not surprising that the United States and Canada, neighbors and allies, are so interested in developing the oil sands and increasing their joint “domestic” supply of crude oil. Figure 33 illustrates that energy security is a classic example of an externality that is not factored into the market price of oil. Since domestic production in the United States in Canada responds to demand, the long-run supply curve is upward sloping (S_{d0}). As the United States and Canada are price takers at P_0, foreign supply of oil is horizontal (S_{f0}). Foreign oil, however, has an additional cost (P_1 - P_0) associated with the risk premium that correlates with import vulnerability (S_{f1}). Without taking into account this risk premium, the market determines that domestic production should be Q_1 and foreign imports should be $Q_5 – Q_1$. If the risk premium is taken into account, however, we see that oil is over-

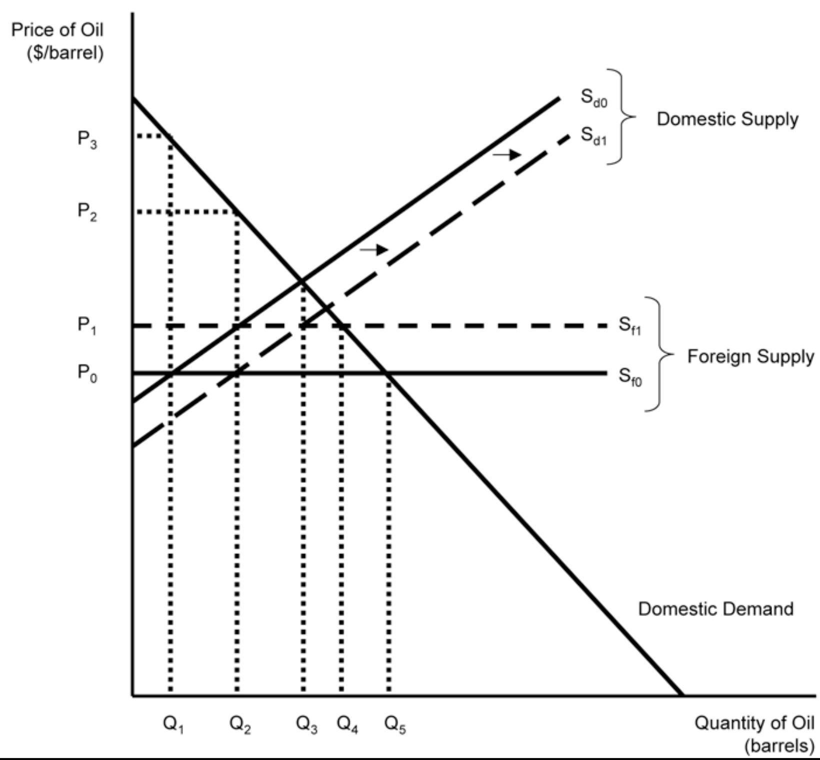


Figure 33. The Price of Energy Security in the U.S. and Canadian Oil Market. (Source: Tietenberg)

imported, as the efficient level of domestic production should be Q_2 with imports only amounting to $Q_4 – Q_2$. If there were to be a supply disruption and foreign oil imports were temporarily unavailable due to geopolitical crisis, prices for oil would rapidly increase to P_3 with domestic production remaining Q_1 because domestic supply cannot quickly expand. With an increase in long-run domestic supply in the oil sands (S_{d1}), both the United States and Canada would reduce their exposure to risk. Domestic production would rise to Q_2, and imports would decrease to $Q_4 – Q_2$. If a foreign supply disruption were to occur, the corresponding rise in price would only be to P_2. Therefore, if governments and the oil industry are concerned about energy security, some of the risk associated with developing the oil sands because of their high capital and operating costs is mitigated. While current oil prices allow oil sands operators to make a sizable, if somewhat uncertain, profit, it should be noted that some oil companies, such as BP, have found this variability in profit too risky to justify investment in the production of bitumen from the oil sands.[6] Therefore, a firm's other opportunities for development, and hence attitudes toward risk will determine whether it chooses to invest in the oil sands.

4.3 Project Economics

As firms invest in, build, and operate oil sands facilities, avoiding increases in the already high capital and operating costs is a significant challenge. Indeed, this has been the case since the beginning of commercial production in the oil sands. When designed in the early 1970s, Syncrude projected its plant would cost less than \$1 billion and produce oil at a cost of \$9.50 per barrel.[7] By the time the plant came online in 1978, the project cost \$2.5 billion, with synthetic crude oil production costs of \$30 per barrel.[8] These cost overruns have continued to the present day, and managing mega-projects in the oil sands is notoriously difficult. The National Energy Board (NEB) wrote in its 2004 report on the oil sands that cost overruns occur because of "insufficient front-end engineering; inadequate management control of the project; and a shortage of skilled tradespeople and experienced supervisory staff, created by constructing these very large projects concurrently." Some analysts believe, however, that budget increases "should not be considered as cost overruns, but as the true cost of construction of these large complexes."[9] The theory behind these cost increases will frame the economic analysis later in this chapter.

These project and operating cost overruns are the hallmarks of an increasing cost industry that suffers from external diseconomies of scale, as depicted in Figure 34. In Period 0, both the firm and market are in equilibrium. There are no excess profits for the firm, as short run marginal cost (MC_{SR}) equals short run average total cost (ATC_{SR}), and the price of oil is determined by the intersection of supply (S_0) and demand (D_0). Each oil sands operator produces q_0, with n_0 firms in the oil sands industry. In Period 1, demand for oil increases, which in turn raises the price of oil in the short term. This establishes a new, temporary equilibrium that encourages the existing firms to produce more, adding expansions to existing facilities. The oil sands firm is now producing q_1 at price P_1, yielding an additional net profit. This profit encourages other firms to enter the industry. In Period 2, new firms have entered the oil sands industry, expanding supply with new plants and extraction facilities. Although a new equilibrium is established, now with n_2 firms producing q_2 each, price has not returned to its initial level, so that $P_1 > P_2 > P_0$, resulting in an upward sloping long-run supply curve (S_{LR}). These higher prices affect the fundamental cost structures of each firm, raising the average total

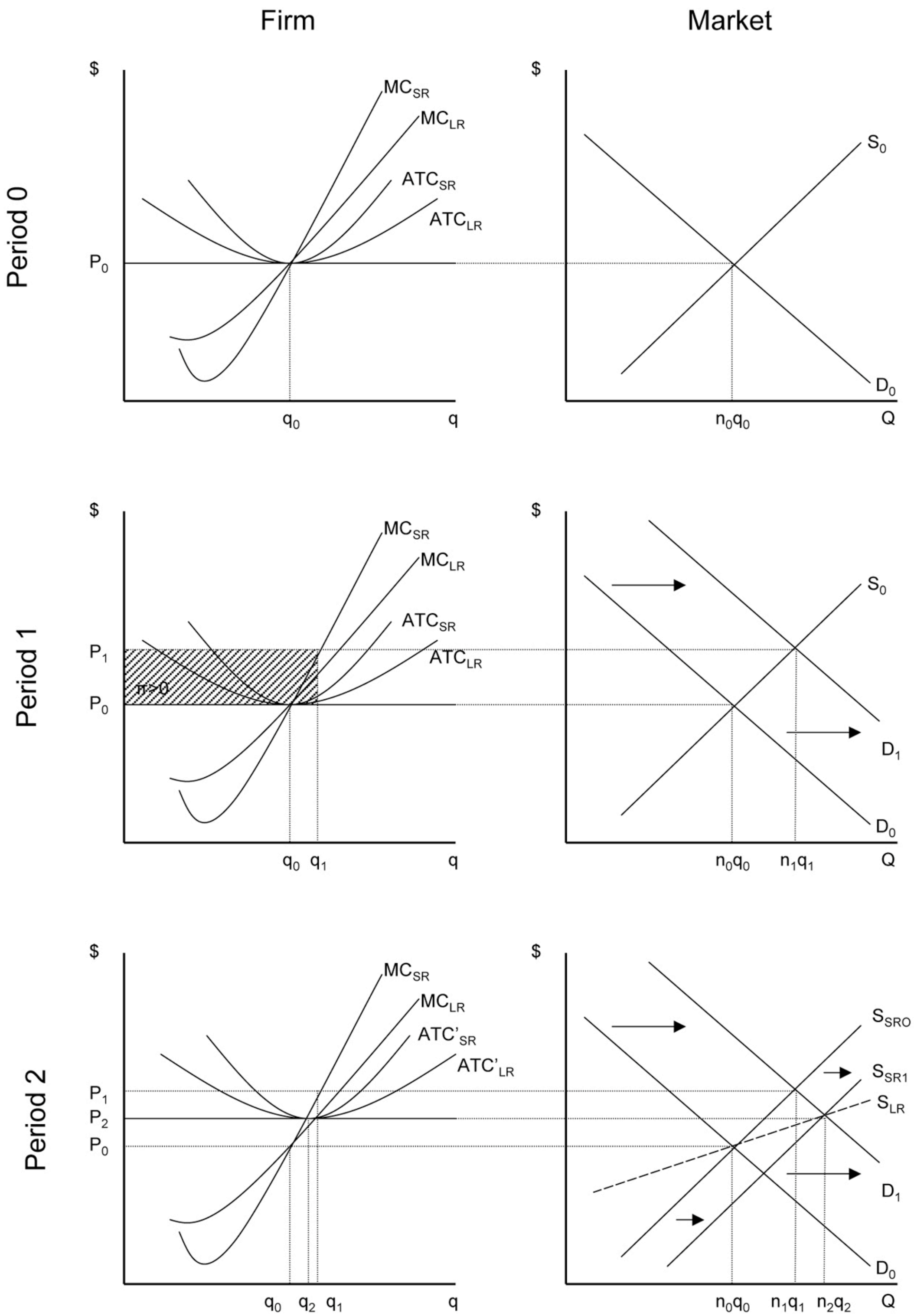


Figure 34. Generic Firm in an Increasing Cost Industry that Experiences Increased Market Demand. Note profits in Period 1 (indicated by shading and π>0) and the upward shift of the ATC_{SR} and ATC_{LR} to ATC'_{SR} and ATC'_{LR} in Period 2. (Source: Wolcowitz).

cost curves. This in turn establishes a new equilibrium for each firm. Hypothetically, an individual firm that produces in all three periods will see production surge from q_0 to q_1, and surprisingly drop slightly to q_2 in Period 2. Therefore, if firms indicate that they will reduce their production targets due to increased costs, this indicates that the oil sands industry may be operating under a scenario similar to Period 2. This situation will be referred to later in this chapter as an indication of oil sands firms reducing their individual growth in order to adapt to higher capital and operating costs.

There are two ways to explain this increase in average total cost – pecuniary effects and technical effects. Pecuniary effects are a consequence of input prices. Because the oil sands firms are located in the same geographic region, they compete for the same input resources. If each firm is attempting to increase production, a process that requires labor and capital, competition dictates that prices for labor (wages) and capital equipment (CAPEX) will increase. Technical effects are a change in the amount of an input to create the same amount of product output. For example, the increase in in-situ production has changed the input demands for oil sands, requiring more natural gas per barrel of production than mining production. In addition, as the environmental consequences of the oil sands have grown, mitigating these externalities, such as adding SOx scrubbers or increasing water recycling have added to production costs per barrel of synthetic crude oil. While technical effects do play a role in the changing cost structure of oil sands firms, pecuniary effects account for the majority of the average total cost increase and will be the focus of this chapter's economic analysis.

Historical data from oil sands projects substaniates this trend of increasing costs. In 1998, Suncor's $1.5 billion Millennium expansion was expected to decrease operating costs in 2002 to $7 per barrel of synthetic crude oil.[10] By 2001, however, the expansion was expected to produce at a cost of $9 per barrel of synthetic crude oil.[11] It is almost certain that pecuniary effects played a significant role in this cost increase, as Suncor's Millennium expansion was only one of three concurrent mining projects at the time (the other two being Syncrude's Stage 2 Expansion and Shell Canada-led Athabasca Oil Sands Project). As a testament to the increasing cost industry and external diseconomies of scale, all three projects were built 50 percent over budget. This trend can be clearly documented by Syncrude raising the budget for its Stage 3 Expansion twice, once in 2003 from $3.2 billion to $4.4 billion, and then once again a year later to $6.0 billion, a net increase of 90%.[12] This historical situation of multiple projects competing for limited labor and capital equipment resources will undoubtedly be repeated in the near future, with the Energy and Utilities Board approving three new mega-projects this winter: Suncor's Voyageur expansion, Athabasca Oil Sands Project expansion, and Imperial Oil's new Kearl mining operation.

These new mega-projects display continued investor confidence in the oil sands, despite the rising costs of producing synthetic crude oil. Oil sands facilities currently under construction, such as Opti/Nexen's Long Lake SAGD and upgrader project had budget increases from $2.9 billion in December 2005 to $3.7 billion in July 2006 to $4.1 billion in October 2006, which is a net increase of over 40%.[13] Shell Canada has also acknowledged dramatic cost increases with its Athabasca Oil Sands Project, which have risen from an original budget of $3.5 billion to $11.3 billion as of August 2006. These kinds of cost increases have made the industry reassess their exposure to risk, as Shell Canada's CEO said "I'd love everybody to back off. [Announcing the cost increase in summer 2006,] I did sort of have this macabre thought that maybe one or two people would" reconsider their competing projects' timeline or viability.[14] The *Globe and Mail*, reported in November 2006 that "Petro-Canada…soon decided to postpone its decision [to go ahead with] the Fort Hills mining project, which could cost between [$11.5-16.8] billion, due to increasing capital costs."[15] One month later, Petro-Canada indicated that it was reviewing the possibility of reducing the size of the opening phase of its mining project, rather than postponing the project altogether, in order to keep costs under control and keep the project on schedule.[16] This is extremely significant, as it may be the first instance of the theoretical effect of increasing average total cost curtailing production capacities due to external diseconomies of scale. Petro-Canada's announcement, therefore, would indicate the industry is moving towards Period 2 in Figure 34 and is accepting a higher cost structure as part of its business-as-usual planning scenario.

Despite these trends, some oil sands operators have maintained their projects on or near budget. Although most of the large projects are over budget, smaller projects appear to have been able to avoid some of the labor and construction cost pressures. Husky completed its Tucker Oil Sands Project on time and under its $500 million budget.[17] Even large mining and upgrading projects, such as Canadian Natural Resources Ltd.'s Horizon facility, can remain close to budget because of prudent business decisions like buying materials such as steel in advance of cost increases, providing significant contingency flexibility as a precaution against cost sensitivities, and insulating the project from labor shortages.[18] The president of CNRL said in November 2006, while Petro-Canada was simultaneously reconsidering construction, that "labour is not as big an issue as we forecast" and that its Horizon oil sands mine was near its $6.0 billion original budget. The company, however, is bolstering its workforce by "flying in about 40 per cent of its workers from other provinces, using its own airstrip," insulating it somewhat from the Alberta labor shortage.[19] The following month, Synenco Energy Inc. announced that in order to save $1.1 billion from its $5 billion budget for its mining facility, the firm would use its partner Sinopec, a Chinese oil firm, to manufacture equipment in Asia. The equipment will then be shipped across the Pacific into the Arctic Ocean and down the Mackenzie River, eventually reaching the mine site. These barged modules would reduce both capital construction costs and labor requirements in Alberta, resulting in half the peak workforce needed for a traditional construction project of similar size.[20] By manufacturing equipment outside of Alberta (reducing capital costs), or avoiding competition in the local labor market (reducing the upward pressure on wages), these firms have demonstrated the significance of pecuniary effects on the industry. The above extreme, innovative solutions are a perfect case study of what oil sands operators may need to do in order to keep projects near budget in the future.

4.4 Cost Structures and Capital Costs

While all firms in the oil sands industry have felt pressure from increasing costs, it is important to understand that oil sands operators do not face equal exposure to the same cost components. Differences in cost structures are due to the unique input requirements for mining, in-situ, and upgrading facilities. An October 2005 Canadian Energy Research Institute report studies operational cost structures as documented in environmental impact assessments for mining, mining/upgrading, in-situ, and in-situ/upgrading oil sands projects.[21] Studying Figure 35, one can readily see that the major operational costs for the oil sands are manufacturing goods (capital equipment),

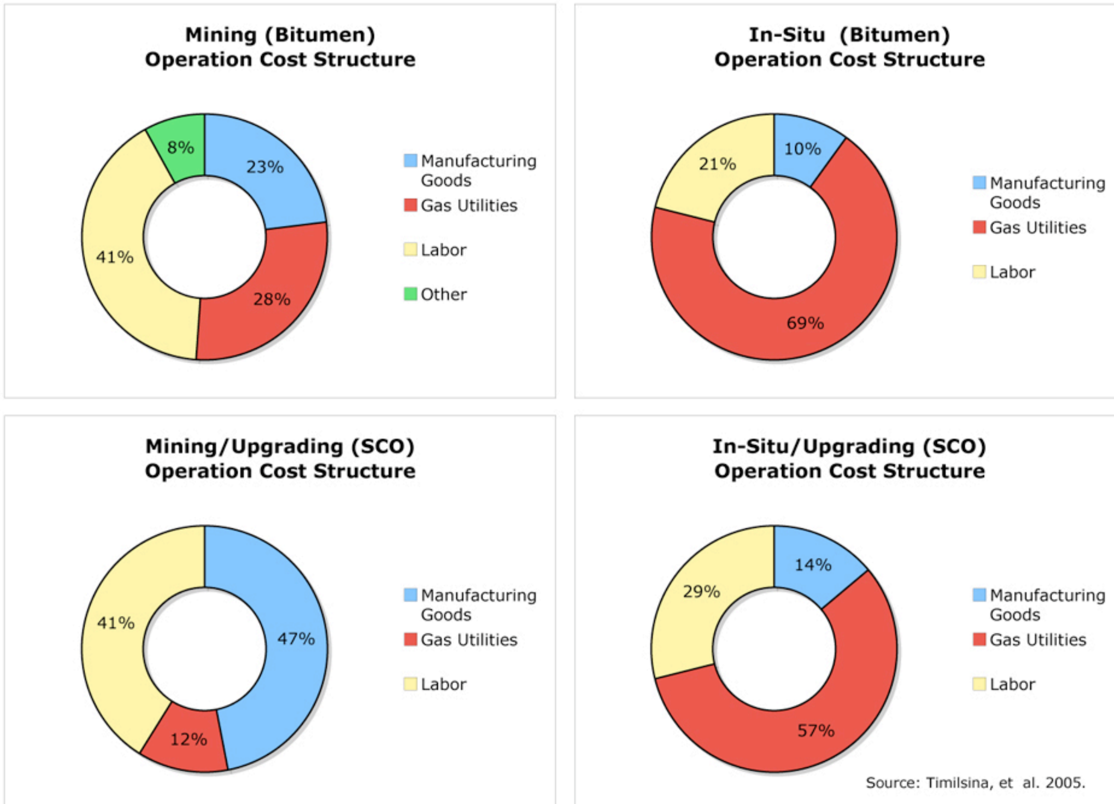


Figure 35. Comparison of Oil Sands Operation Cost Structures. (Source: CERI)

gas utilities, and labor. More specifically, mining operations with and without upgraders have approximately twice the percentage of their budget devoted to manufacturing goods and labor than those components for in-situ projects with and without attached upgraders. On the other hand, in-situ and in-situ/upgrading projects devoted approximately three times the percentage of their budget to gas utilities compared to those of mining and mining/upgrading projects. These distributions of costs result in significant differences in price vulnerabilities, with mining operations particularly sensitive to labor and capital pecuniary effects and in-situ facilities particularly vulnerable to fluctuations in natural gas market prices. Referring back to the section on project economics, oil sands companies are price takers for both labor and gas utilities. As such, in order to reduce costs, operators can either substitute labor and energy with capital or they can seek to

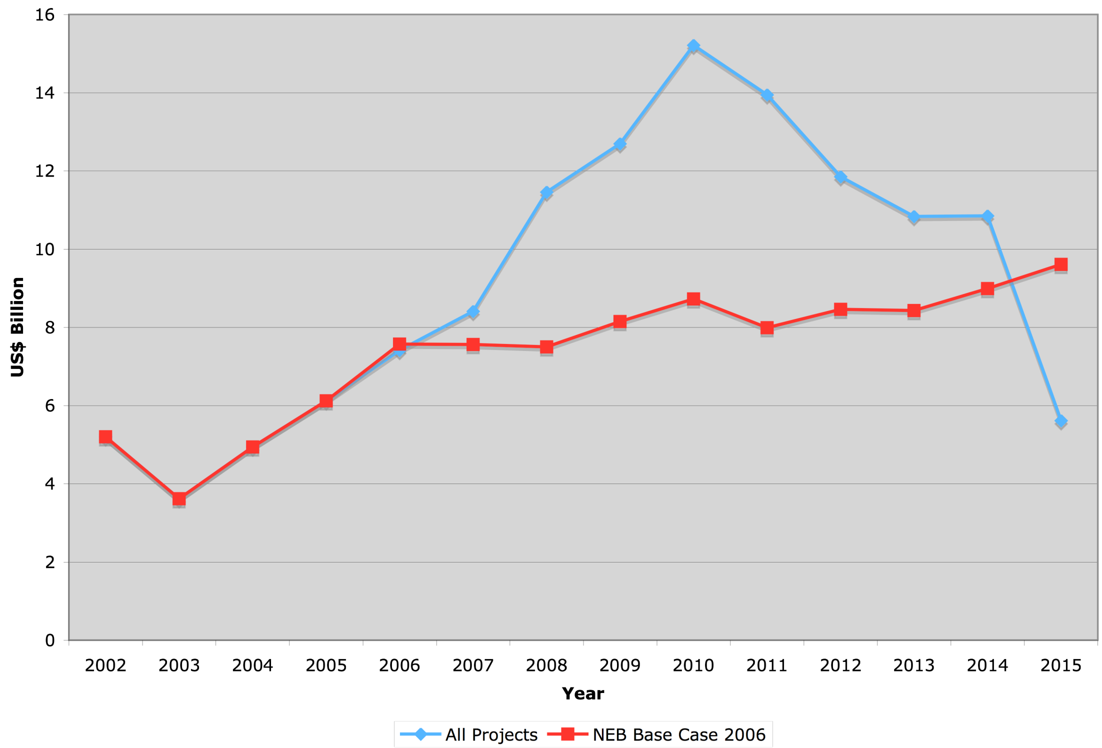


Figure 36. Estimated Capital Expenditure in the Oil Sands 2002-2015. (Source: NEB)

mitigate the expenditure (for example, either via importing workers for lower contract wages and lower total cost or hedging with natural gas futures). Oil sands companies, however, do have some degree of influence over capital expenditure through project management planning. Climatic and economic factors, however, make it twice as expensive to build oil infrastructure in Fort McMurray compared to along the U.S. Gulf Coast, which is the benchmark for oil industry construction.[22] Managing these capital expenditures will be particularly crucial to maintaining the current growth rate of the oil sands.

Producing synthetic crude oil from the oil sands is a capital-intensive process. According to the National Energy Board (NEB), if all planned projects are to be built on schedule, Alberta is expected to require approximately $108 billion of oil sands investment between 2006 and 2015 (see Figure 36). Due to the complexity of these projects, however, it is highly improbable that all projects will be built, let alone stay on schedule. The NEB's June 2006 report on projected oil sands production therefore assumes a 24 percent discount on this spending.[23] By simply dividing the industry's expected capital expenditure, $83 billion, by the projected increase in daily production (1.8 million barrels per day), a rough estimate of capital expenditure (CAPEX) is $46,000 per barrel per day. The NEB first released average capital cost estimates for new facilities in a 2004 report, which were later updated in a 2006 report.[24] The most recent numbers reflect a 25 percent increase in CAPEX to $13,200 per barrel of bitumen per day for SAGD and a 30 percent increase in CAPEX to $45,900 per barrel of synthetic crude oil per day for an integrated mining (extraction and upgrading) facility.[25] Keeping in mind that the oil sands industry is composed of both kinds of projects, the hypothetical CAPEX of $46,000 per barrel per day calculated above seems reasonable, as the in-situ facilities must also have upgraders built to process bitumen into synthetic crude oil. These estimates, however, may already be out of date, as the NEB since its June 2006 report has revised its capital cost estimates up, reflecting a continued 18 percent per year increase in cost. In an interview in August 2006, members of the commodities business unit at the National Energy Board suggested that the target CAPEX for a new project was now approximately $53,000 to 62,000 per barrel per day.[26] Therefore, if these estimates are inaccurate after even a period of months, it is unclear how well any estimate of CAPEX may reflect the true investment character, or how well any firm may be able to predict the cost of its investment. Historically, CAPEX costs have varied widely, as projects in the early- to mid-2000's, such as Suncor's Millennium expansion or

Syncrude's Stage 3 Expansion, ranged in CAPEX from $27,300 per barrel per day to $61,700 per barrel per day respectively. While these capital expenditures were not on new facilities (and thus take advantage of internal economies of scale), additional unexpected expenses were incurred due to the complexity of adding additional capacity to these existing projects.[27] In comparison, a new mining project that began production in 2003, Albian, had capital costs of approximately $39,700 per barrel per day.[28]

Projects currently under construction, however, are facing much higher capital expenditures. Nexen's capital costs for the construction of Long Lake, a SAGD with attached upgrader project doubled to $105,800 per barrel of synthetic crude oil per day in October 2006.[29] Shell Canada's expansion at the Athabasca Oil Sands Project with an upgrading component was reported to cost $112,900 per barrel of synthetic crude oil per day.[30] Analysts have suggested that marginal capital costs for a new mining with upgrading project under consideration in late 2006, such as Petro-Canada's Fort Hills, are approximately $79,400 to $112,900, but it is unclear how accurate these projections may be.[31] In August 2006, the NEB agreed with concerns voiced by investors that the capital costs of over $88,200 per barrel per day for the Athabasca Oil Sands Project are "much too high" and may be a result of project management buffering cost estimates.[32] On average, Alberta Energy believes that some companies have been building in 10-20 percent cost buffers.[33] With increasing uncertainty of the costs in the oil sands industry, this is probably prudent project management. These rapidly increasing capital costs have already forced firms to scale back the production levels of new facilities, and soon will begin to act as a barrier to entry for new firms. Both of these scenarios will add to the risk that a firm's production revenue will be unable to pay off the capital costs debt accrued during construction and thereby curtail the growth of the oil sands.

4.5 Operating and Supply Costs

As the oil sands industry is exposed to volatile capital equipment, labor, and energy costs, firms have a profit incentive to reduce their operating and supply costs. In the 1990s, high operating costs and low market prices for crude oil forced oil sands operators to increase efficiency and look at synergies across production facilities.[34] With the adoption of truck and shovel mining, hydrotransport, and greater returns to scale, Suncor reduced its operating costs from $14 per barrel of synthetic crude oil to $9 per barrel in 1998.[35] In 2000, the NEB predicted that operating costs would be $7 per barrel of synthetic crude oil in 2004, with operating costs of $5 to $6 per barrel of synthetic crude oil by 2015.[36] However, by 2005 average costs had risen to $22 to $25, largely due

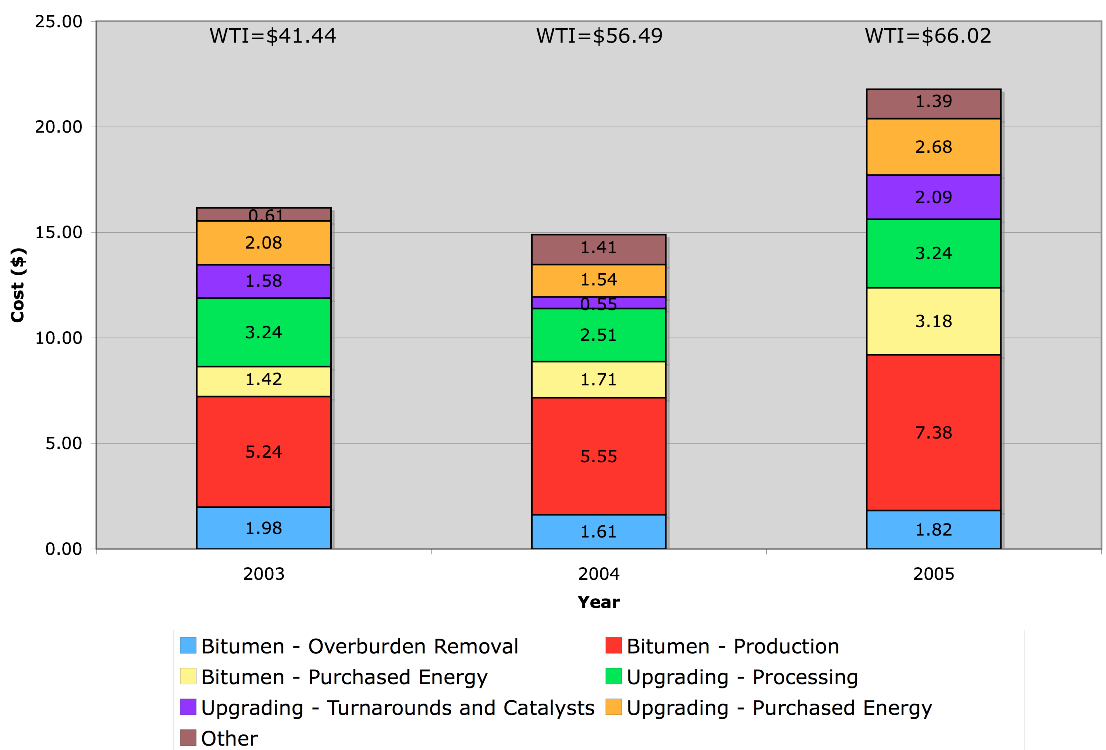


Figure 37. Syncrude Operating Cost Structures 2003-2005, as compared to WTI average prices. (Source: Canadian Oil Sands Trust Annual Reports 2003-2005, EIA).

to an increase in the global cost of natural gas energy and local pecuniary effects associated with construction.[37] Syncrude's operating cost structure demonstrates the rapid post-2004 increase in costs (see Figure 37). Most of the existing oil sands mine operators currently have similar cost structures with operating costs around $25-30 per barrel of synthetic crude oil.[38] Oil sands facilities that are currently under construction, however, are projecting much higher costs of extraction than established projects such as those at Syncrude. OPTI/Nexen's Long Lake SAGD Project, had operating costs of about $45 per barrel in October 2006.[39] Also in October 2006, EnCana's CFO said that their SAGD oil sands project cost structure was based on a WTI average of $50 per barrel of oil, and that costs were approximately $40 per barrel. Oil sands industry analysts, however, doubted that this was the case and some believed the project would be uneconomic below a market price of $45 per barrel.[40] Although for the time being, the price of crude oil seems to be slightly above the operating costs of these projects, it is unclear how much profit a firm would be able to generate on such small margins. The same month, Petro-Canada was reconsidering their Fort Hills mining project with operating costs of $28 to $31 per barrel of synthetic crude oil.[41] Petro-Canada's decision illustrates extraordinary risk aversion to the potential variability in cost estimates, which depend on project management, cost structure, and production technology.

The National Energy Board (NEB) has attempted to standardize projections for the supply costs of a hypothetical new oil sands facilities (see Figure 38). In three reports over a six-year period between 2000-2006, supply costs for a hypothetical SAGD project have increased 82%, whereas supply costs for a hypothetical integrated mining and upgrading project have increased 130%.[42] Between 2004 and 2006 alone, the NEB's projections for a new SAGD project showed capital costs increased 45 percent and natural gas costs increased 88 percent, whereas non-gas operating costs decreased 30 percent due to better technology and operations management. In contrast, the NEB's estimates for a new integrated mining and upgrading project in the same period showed capital costs increased 37 percent, natural gas costs increased 88 percent, and non-fuel operating costs increased 20 percent.[43] As seen in Figure 39, these increases in costs changed cost sensitivities for oil sands facilities. Overall, uncertainty in costs measured by percentage change in supply costs decreased between 2004 and 2006 for integrated mining operations, but in contrast, increased for SAGD operations. In absolute terms, however, cost uncertainty increased in every category for both integrated mining and

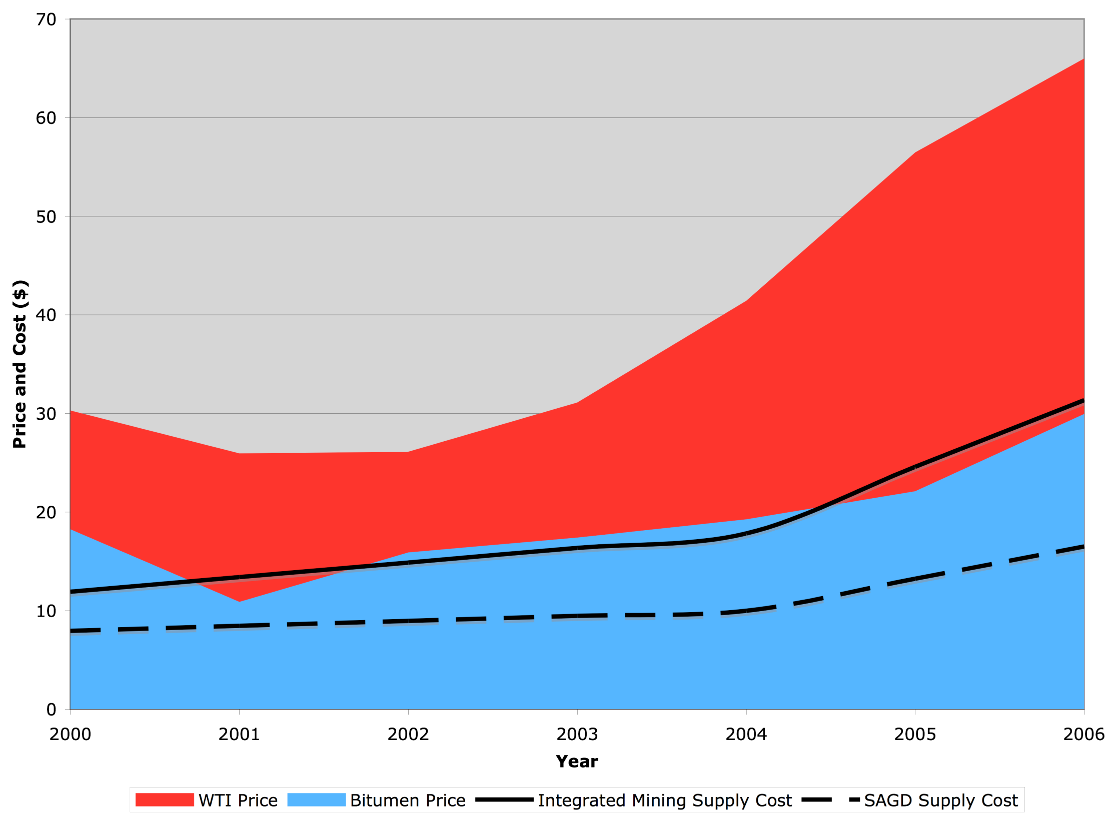


Figure 38. Comparison of New Facility Supply Costs for Integrated Mining and SAGD and Commodity Prices. (Source: NEB, EUB, EIA)

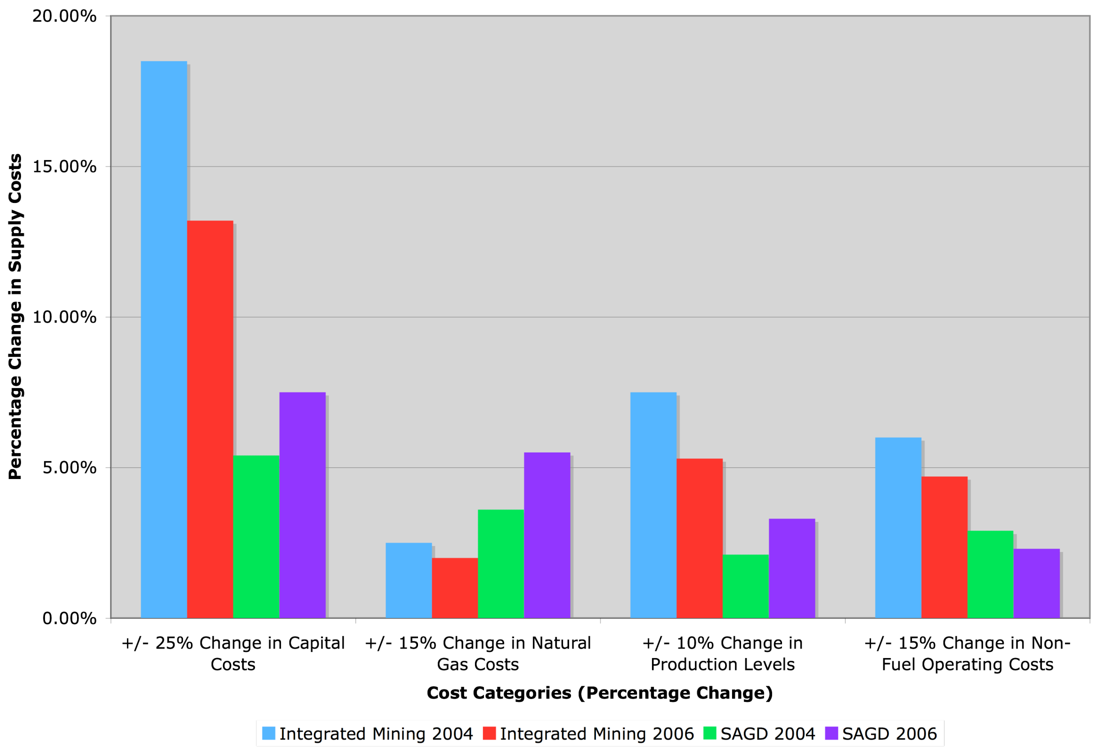


Figure 39. Comparison of New Facility Supply Cost Sensitivity Analyses for Integrated Mining and SAGD Projects (Source: NEB)

SAGD. These cost uncertainties are important, as the risk of greater absolute changes in cost for a given change in input prices decreases the likelihood a firm would invest in new production in the oil sands. In addition, this operating cost analysis substantiates the fact that the oil sands industry is in transition between Period 1 and Period 2 in Figure 34, with the industry adapting to the higher costs associated with external diseconomies of scale.

New technology, however, may disrupt this trend of cost increases. By introducing shovel and truck mining along with hydrotransport, the oil sands industry innovated in the early 1990s and sharply reduced supply costs. With technologies such as VAPEX on the horizon, these cost reductions may occur once again. The National Energy Board predicts that VAPEX may have capital costs 25 percent less than those for SAGD and only half the operating costs.[44] As VAPEX is still in the pilot phase, it has not yet experienced pecuniary effects, and as such, judgment on the cost advantages of VAPEX should be reserved until the beginning of widespread implementation.

4.6 Upgrading and Export Markets

In order to maximize revenue from production, the oil sands operators must convert bitumen into synthetic crude oil and transport this to refineries and end consumption market. This requires upgraders and pipelines to operate in a delicate balance. As the oil sands industry is a price taker for synthetic crude oil, upgraded bitumen will always receive global market price, as this price is independent of oil sands production. The industry, however, is a price maker for bitumen, and therefore, if not enough of the bitumen is upgraded to synthetic crude oil, a glut of bitumen will depress its market price. The difference between the market prices of synthetic crude oil and bitumen provide the incentive for oil sands operators to construct upgraders in order to capture profits from the heavy bitumen discount. The percentage discount in price from a benchmark such as West Texas Intermediate to bitumen is highly variable, ranging from approximately 35 percent to 60 percent (see Figure 40). The Alberta government is keen to expand upgrading, thereby capturing this differential and collecting more income and revenue within the province.

Building an upgrader in Alberta's current economic climate is extremely challenging due to the same high construction, engineering, and labor costs that impact mining and SAGD projects. In addition to these fixed costs, upgraders are large consumers of natural gas for heat and hydrogen addition. Upgrader economics, therefore, are highly susceptible to changes in these commodity prices. In order to offset high capital and operating costs, upgraders must take advantage of economies of scale in order

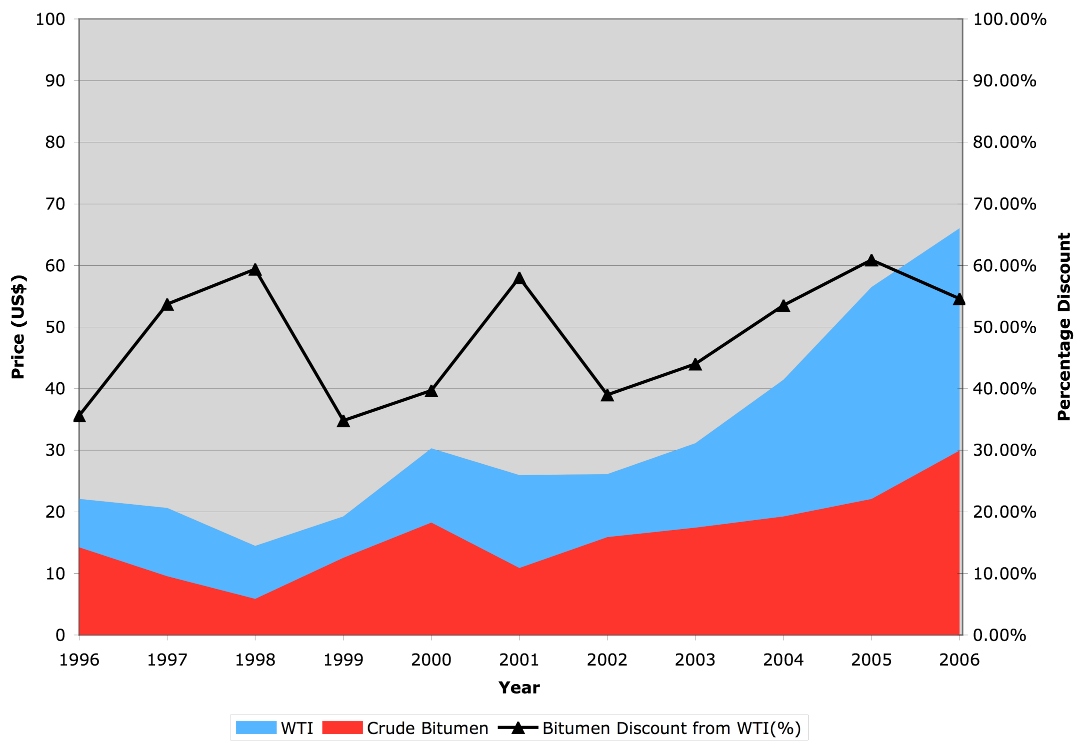


Figure 40. Comparison of Bitumen and West Texas Intermediate Crude Oil Prices. Note bitumen price percentage discount from WTI. (Source: NEB, EUB, Pembina)

to be profitable. This can be achieved in one of three ways: attaching the upgrader to mining or large in-situ projects (Suncor, Syncrude, CNRL, and OPTI/Nexen), centrally locating the upgrader so as to take feedstock from several small in-situ projects (merchant upgraders such as Husky Energy's Lloydminster Upgrader), or attaching to existing refineries to take advantage of operational synergies (Shell Canada's Scotford Upgrader).

In the coming decades, Alberta's government would like industry to build 2.9 million barrels per day of upgrading capacity.[45] Important consideration must be given to where these upgraders are constructed. While Alberta Energy acknowledges that different companies may have different economic perspectives, it believes the majority of upgraders will not be built close to Fort McMurray because of high labor, capital, and operating costs.[46] Instead, most new upgraders will most likely be built near the existing oil processing infrastructure around Edmonton.[47] For example, Shell-led Athabasca Oil

Sands Project plans on building four new upgrading plants outside of Edmonton, increasing the planned development in Alberta's Industrial Heartland to 12 construction projects worth over $26.5 billion.[48] At the peak of construction between 2009 and 2012, 16,000 construction workers will be working on these projects.[49] With this planned wave of upgrader construction, the Edmonton and Fort Saskatchewan region will face similar challenges to those of Fort McMurray, such as the need for additional roads and the potential risk for massive environmental degradation. Despite these challenges, Ed Stelmach, Alberta's new Conservative Premier and Member of the Provincial Legislature for Fort Saskatchewan, said that he wants to promote bitumen upgrading in the province, as "if we insist on just sending raw product out of this province and adding value to that product in another jurisdiction, the taxes on the value-added product will be paid in that jurisdiction, not in the province of Alberta."[50] This interest in upgrading bitumen is not surprising as the additional government revenues from this process step will be enormous, with the NEB projecting in 2004 revenues of $154 billion between 1997 and 2025.[51] While there is political will to capture the bitumen price differential in the province, the economics of upgrader construction are sufficiently risky so that some investors may give pause to building upgrading capacity in Alberta.

In order to avoid the rapid cost increases in Alberta, some companies are planning on shipping diluted bitumen to the U.S. for upgrading. In November 2006, EnCana and ConocoPhillips reached an $11 billion agreement that uses the latter's U.S. refinery capacity to upgrade diluted bitumen. This, in turn, allows EnCana to hedge against the cost of constructing an upgrader in the overheated Alberta economy.[52] This strategy requires a capital expenditure of approximately $30,900 per barrel per day, only slightly more than the NEB's 2006 estimate of $28,200 in CAPEX per barrel per day for the construction of a new standalone upgrader in Alberta.[53] Taking into account the risk premium for reduced exposure to increasing costs in the Alberta construction market, EnCana's strategy may be the more cost effective option in the end. The option of exporting diluted bitumen to the United States in order to avoid the potential higher cost of upgrading in Alberta deserves greater consideration, especially as future projects may follow EnCana's lead.

Bitumen, however, cannot be transported in an unmodified state through pipelines as it is too viscous, and so it must be diluted with condensates (light hydrocarbon liquids) or synthetic crude oil. When diluent (20 to 50 percent of total volume) is sent to market with the bitumen, it must be either reprocessed in order to be recycled and returned via pipeline, or must be considered a one-way shipping expenditure. Declining production of diluent in the Western Canadian Sedimentary Basin and rising costs of condensates has necessitated the construction of pipelines to return diluent from the Midwest to Alberta. As an alternative to avoid the cost of recycling condensate via pipeline, producers may use synthetic crude oil from Fort McMurray upgraders. This has two advantages: the first being that more bitumen will be upgraded in the region and the second being that the synthetic crude oil diluent is a refineable product and does not need to be recycled. Therefore, the oil sands industry may rely less on diluent and more on its own synthetic crude oil production to ship bitumen to upgraders.

The growth of production in the oil sands has led to an increasing need for pipeline capacity to transport diluted bitumen and synthetic crude oil from northern Alberta to refining markets. The National Energy Board (NEB), a federal government

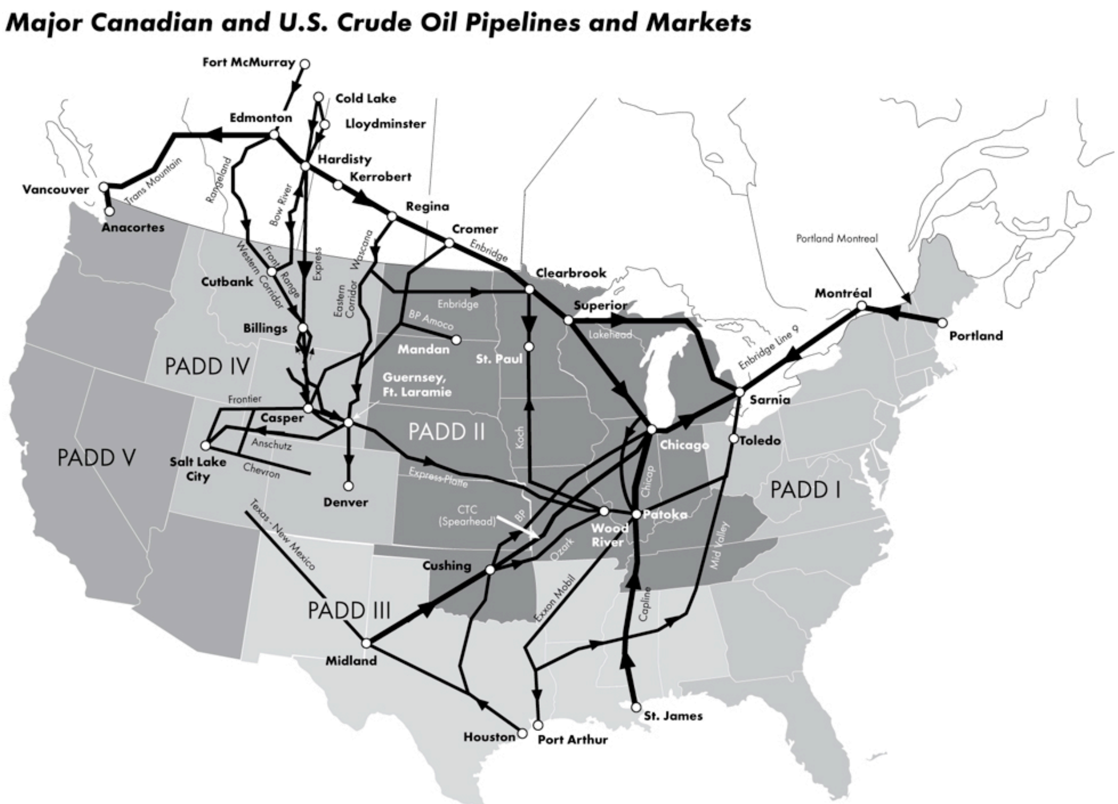


Figure 41. Major Canadian and U.S. Crude Oil Pipelines and Markets. (Source: NEB)

entity with jurisdiction over pipeline regulation and approval, has studied market demand and industry supply extensively. Pipeline companies, normally seen as the most risk-averse components of the energy sector, have grown increasingly interested in providing markets for oil sands products.[54] The NEB and the oil sands industry see the United States as the main area of demand growth. As illustrated in Figure 41, the continental U.S. is divided into five Petroleum Administration of Defense Districts (PADD), which represent somewhat separate markets with limited interconnecting pipelines. In 2005, Canadian crude oil supplied approximately 10 percent of the feedstock for U.S. refineries, and this should grow with political concerns over energy security. Seventy percent of the Canadian exports were transported to PADD II, of which 39 percent was from the oil sands. PADD IV will continue to receive Canadian crude despite increased local production in areas such as Wyoming and Colorado. Expansion of product to the PADD V market may occur, but Canadian crude must compete with feedstock from Alaska. The NEB suggests that opening up the PADD V market with new pipelines may not happen for several years, but may afford the opportunity of decreasing the light/heavy crude differential because of bottlenecks in Alberta and PADD II refining.[55] New legislation in California, however, requires transportation fuels to reduce the lifetime carbon emissions from both their production and consumption, which may put the oil sands at a disadvantage in the U.S.'s largest fuel market.[56]

With the bitumen price differential in mind and the idea of expanding export options, pipeline companies such as Enbridge have looked to rising Chinese demand for oil as a potential new market. The proposed Gateway pipeline over the Rocky Mountains to the British Columbia coast would be expensive, but would have the benefit of diversifying geographic end markets, with British Columbia's deep-water ports shipping product to China. The NEB's priorities, however, are to: "fill up existing markets", "further penetrate" U.S. markets by targeting refinery expansions and conversions, and "branch out and develop new markets" such as California and Asia.[57] Although these priorities were clearly articulated by the NEB, many larger questions remain. Volatility in crude oil prices presents risk and uncertainty in establishing markets and convincing pipeline investors into long-term supply and demand relationships. Because of this uncertainty, it is unclear whether bitumen should be upgraded by oil sands producers into synthetic crude in Alberta, or whether non-Albertan refiners should adapt to heavier grades of crude. All these questions will affect the supply and demand for oil sands products, and so impact the future growth of the industry. The growth of the industry, will therefore depend on continental energy needs. The Alberta government has yet to adapt to this paradigm, and must quickly do so, as both the Canadian federal government and oil sands industry have recognized the need for greater integration between producers and consumers.

For the Alberta government, this greater integration between producers and consumers may lead to decreasing control over the oil sands resource, particularly as domestic energy companies are acquired by foreign multinationals. With Royal Dutch Shell's October 2006 bid for buying out the remaining minority shareholder interest in Shell Canada, it is possible that the oil sands will be seen less as an unconventional Canadian phenomenon and more as an investment in a low geopolitical risk region that has an existing infrastructure closely linked to North American energy markets. In addition, Royal Dutch Shell's $7 billion bid tacitly demonstrates confidence in higher oil prices.[58] The company's investment decision is directly opposite that of Petro-Canada, which a month later, put some of its in-situ properties up for sale, indicating that it has decreasing confidence in the development of the Athabasca oil sands.[59] There may be, however, other explanations for Royal Dutch Shell's bid, that might include reinvestments of profit in the company's last semi-independent subsidiary, or an interest in controlling project planning from the continental or global level. The latter is the most likely explanation, as Royal Dutch Shell's CEO said that the buyout was to integrate Shell Canada with the energy strategy of the parent company. According to the Financial Times, "Shell has set a target of producing 10 [to] 15 percent of its output in 'unconventional oil', which includes oilsands and heavy oil, by 2015."[60] In addition, the president of Shell Oil Co. (the United States subsidiary) said that the oil sands would be a valuable supply for U.S. demand, and would allow for continent-scale planning, potentially allowing for upgraders and refineries to be built in the U.S. that would use oil sands feedstock.[61] It is reasonable to infer that the investment of firms in the oil sands, especially as part of a continental energy market, indicates industry confidence in the resource's future growth potential.

Chapter 5 - Consequences of the Growth of the Oil Sands

5.1 Introduction

Given the increasing confidence in long-term profitable production, it is imperative that Alberta examines the consequences of the growth of the oil sands. Chapters 3 and 4 of this thesis represent the first comprehensive compilation and analysis of *both* the environmental and economic impacts of oil sands growth known to the author. Chapter 5 will investigate the consequences of the growth of the oil sands from an economic and socioeconomic perspective. Based on this analysis, Chapter 6 will offer several recommendations and conclusions on how to reconcile the environmental and economic challenges facing the development of the Athabasca oil sands.

In the short-term, however, the increasing use of natural gas as a result of rising production is an instructive case study of how intertwined the environmental and economic issues of the oil sands industry have become. As described in Chapter 2, oil sands operators require natural gas combustion as a heat source for bitumen extraction, plant utilities (ie. electricity), and upgrading. The volume of natural gas required by these facilities varies, with mining requiring 250 cubic feet per barrel of bitumen, SAGD requiring 1000 cubic feet per barrel of bitumen, and upgrading requiring 500 cubic feet per barrel of synthetic crude oil. These requirements and associated operating costs are so significant as to encourage firms to innovate new extraction technologies such as VAPEX or THAI (as examined in Chapter 2) or to avoid using natural gas as an energy source altogether through technologies such as asphaltene gasification (as examined in Chapter 3). The logic here, from the point of view of the firm, is that natural gas costs, as analyzed in Chapter 4, account for 28 percent of mining total operation costs and 69 percent of SAGD total operation costs, and therefore have a large effect on the revenue from a project's production. The impact of the usage of natural gas, however, is not limited to merely the firm's profit and loss statements. The consumption of natural gas for processing the oil sands directly influences the greenhouse gas intensity of the operations. Therefore, any future greenhouse gas regulation will have an effect on the amount of energy used in the oil sands industry. As discussed in Chapter 3, the Alberta government is concerned that the federal government, through greenhouse gas regulations, will attempt to influence the development of the Alberta oil sands, and it indeed may have this effect. Even if these environmental and economic challenges are overcome, larger issues with the oil sands demand for energy and the domestic supply of natural gas loom in the next decade.

Despite the large natural gas reserves in the Western Canadian Sedimentary Basin, it will be a challenge to supply enough natural gas to the oil sands operations (see Figure 42). Canada's natural gas production in 2005 was 17.1 billion cubic feet per day, enough to supply natural gas exports to the U.S. of 10.2 billion cubic feet per day and domestic consumption of 6.9 billion cubic feet per day.[1] As production matures in the Western Canadian Sedimentary Basin, the natural gas industry is entering a period of supply uncertainty.[2] While natural gas production is expected to remain level through 2015, this is dependent on several new projects, such as the Mackenzie Delta pipeline coming online by that time. The expected production capacity of the Mackenzie Delta in 2015 is a little over 1.4 billion cubic feet per day.[3] As a hypothetical exercise, assuming that the natural gas supply to the oil sands in 2015 consisted of the supply in 2005 in addition to the full capacity of the pipeline from the Mackenzie Delta, the oil sands would

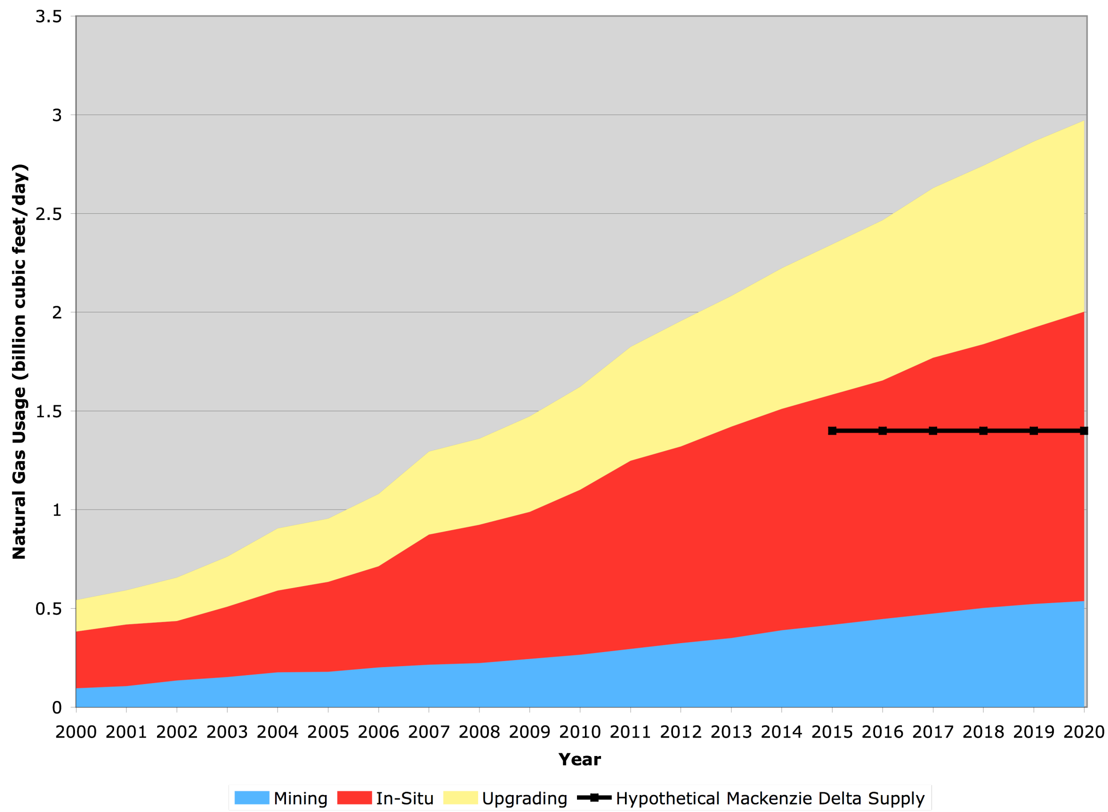


Figure 42. Projected Natural Gas Requirements for Oil Sands Operations. Natural gas usage will grow six-fold between 2000 and 2020. Based on CERI production data, assuming 250 cubic feet/barrel for mining, 1000 cubic feet/barrel for in-situ, and 500 cubic feet/barrel for upgrading. Line displays hypothetical Mackenzie Delta supply of natural gas.

still have a 30 percent supply shortfall in 2015. For perspective, this supply shortfall is equivalent to the total natural gas supply requirements of the oil sands in 2002. Therefore, with such dramatic growth of consumption in the oil sands and minimal growth in domestic supply, it looks likely that Canada will be unable to maintain today's level of exports to the United States. In turn, the oil sands' disruption of natural gas supply and demand in the North American market has heightened energy supply uncertainty and may end up increasing energy prices. Therefore, the increased usage of natural gas in the oil sands may disrupt the continental energy market and Alberta's energy export economy.

Ultimately, the scale of this disruption will depend on the long-term and short-term limits to oil sands growth. There are potentially several limiting factors to the long-term growth of the oil sands: increasing water withdrawals, rising natural gas usage, and escalating capital costs, all of which were diagrammed in Chapter 2, Figure 18 as key inputs of oil sands production. First, let us consider increasing water withdrawals as a limit to production. If we are to accept Alberta Environment's guideline of a maximum usage of 10 percent of the Athabasca River's winter-low flow volume as a development threshold, the river would be able to support the water withdrawals of up to 20 Syncrude mining and extraction facilities. This would in turn equate to a daily production of 5.2 million barrels of bitumen and an annual water requirement of 604 million cubic meters of water (assuming a water to oil ratio of two). This is equivalent to a six-fold increase in production of bitumen and consumption of water from current volumes. If mining operations were to grow to this size, the facilities would require 1.3 billion cubic feet of natural gas per day, or nearly the estimated capacity of the Mackenzie Valley Pipeline. If the oil sands industry grows proportionally from 2020 onwards and we assume constant natural gas intensity, the mining, in-situ, upgrading facilities will require 7.2 billion cubic feet per day of natural gas in order to produce a total of 8.7 million barrels per day of bitumen and 4.7 million barrels per day of synthetic crude oil. This volume of natural gas is greater than the current domestic consumption of all of Canada, and with no foreseeable significant supply growth, this would be an unlikely scenario. Therefore, natural gas will limit the long-term production of the oil sands. The implications of these limitations to growth are far-reaching. First, if habitat degradation is already being observed along the river, a six-fold increase in mining production surely would cause catastrophic damage to the aquatic ecosystem. It would appear that Alberta Environment has set its water usage limits much too high to ensure the safety of the river. These water withdrawal “limits,” therefore, referring to implausible development scenarios, are not effective policy tools, and therefore should be reconsidered. Second, if natural gas is to be the limiting factor in oil sands development, there are several options for the future: improving energy efficiency, switching energy inputs, reducing exports to the U.S., growing domestic supply, or importing natural gas. The first two alternatives are by far the most plausible, but will require significant investments in both research and the retrofitting of capital equipment.

Turning to the short-term, the main limit to growth will be the increasing capital costs of the oil sands industry and the associated labor shortage. In an August 2006 interview, the National Energy Board saw the primary challenges facing the oil sands as labor and commodity price increases, which in turn raise construction and capital costs.[4] The fact that oil sands companies have had to make such an effort to find skilled labor indicates a much larger challenge lies ahead. In an August 2006 interview, Alberta Energy conveyed serious concerns about how to recruit employees in Alberta, across Canada, and around the world in order to avoid a predicted shortage of 86,000 skilled laborers by 2016.[5] In order to entice more labor to enter the Alberta economy, firms will bid up wages, in turn raising the cost of capital construction. The additional investment to overcome these increasing costs will in turn add to inflationary pressures on the Alberta economy.

As the industry grows, its fate will be increasingly interlinked with the entire Alberta economy, and thus make regulations and reforms all the more challenging and complicated to achieve. Understanding the oil sands position in the Canadian and Albertan economies is therefore crucial for the formulation of any public policies that will mitigate the environmental and economic costs of development; change is clearly needed in the near future. The primary market instrument that the provincial government can use to control development is the oil sands production royalty, as an increase in it would effectively decrease the rate of return on oil sands projects. Though this course of action would be unpopular with industry for obvious reasons, the recent negative socioeconomic effects of oil sands development have been such that the Alberta government would be negligent of its constituents not to take *some* action to improve its management of the rate of industry growth. As will be described in Chapter 6, there is an increasing demand for change in environmental and economic policies in Alberta and across Canada. Now is the perfect opportunity for the Alberta government to establish firmer guidelines and alternative futures for the development of the Athabasca oil sands.

5.2 Position of the Oil Sands in the Canadian Economy

As the mining, oil, and gas industries represented 3.6 percent of Canada's GDP in 2006, the growth of the oil sands has important ramifications for the entire Canadian economy. [6] In 2006, Canada's oil and gas industry generated $96 billion in revenue, with payments of $23.8 billion to government coffers.[7] As an area of current and future investment and employment, the growth of the oil sands will not only propel the local and Alberta economies, but also the Canadian economy for several decades to come. The oil and gas industry currently employs 365,000 people directly, with an additional 500,000 jobs impacted by the industry activities, creating an impact on a little over 5 percent of

Canadian employment.[8] The oil sands, therefore, are a crucial component of both the Albertan and Canadian economies.

In 2005, the Canadian Energy Research Institute undertook a macroeconomic study of the impacts of the development of the oil sands. The report clearly demonstrates the complexity and magnitude of the economic effects. CERI predicted that with $83 billion of investment between 2000 and 2020, the oil sands would produce $438 billion of bitumen and synthetic crude oil, assuming $32 per barrel of oil. Assuming $40 per barrel of oil, which is closer to the current price of oil, CERI calculated that the economic impact of the oil sands on Canada's GDP could be $1.213 trillion.[9] Considering that investment will likely be greater than $83 billion and oil prices are likely to be around $50 per barrel, these projections seem relatively conservative, and most likely represent the lower limit of probable outcomes.

The three key categories of economic benefits from the oil sands are a) increases in GDP, b) increases in employment, and, c) increases in government tax revenue (see Figure 43). The distribution of oil sands-generated money across Canada varies significantly depending upon the category. For example, while Alberta enjoys 72 percent of the additional GDP, it will only enjoy 56 percent of the additional employment and 36 percent of the government tax revenues. While the positive economic effects, found throughout the provinces, have supported the notion that all Canadians enjoy the economic benefits of the oil sands, it should be noted that Ontario's economy will enjoy less additional employment as a result of the oil sands than will the economies of foreign countries.[10]

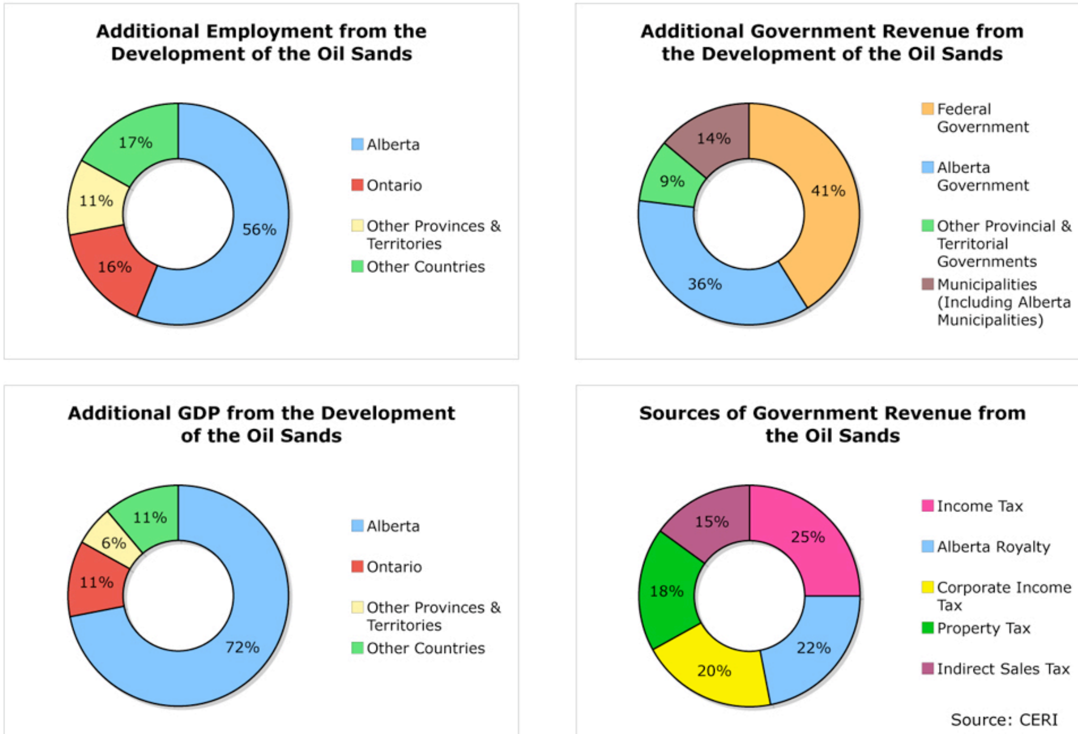


Figure 43. Distribution of Impacts from the Development of the Oil Sands. (Source: CERI)

With Alberta's rapid economic growth, some concern has emerged from the manufacturing sector, particularly in Ontario, that oil sands investment has distorted regional macroeconomics across Canada, particularly in capital investment and net exports. Sizable capital investment into an already robust economy tends to lead to an increase in local prices (inflationary pressures in Alberta). The Consumer Price Index, an inflation benchmark, increased 3.9 percent in Alberta from January 2006 to January 2007, as compared to 1.2 percent across Canada during the same period.[11] Higher employment and levels of commerce in turn fuel an increase in nominal provincial GDP, creating an increased demand for money. In order to compete with other business opportunities, the cost of capital investment increases, which leads to fewer investments with positive net present discounted value, in turn decreasing investment for all industries in Canada. The increase in net exports from Alberta is due to both expanded production and higher market prices for oil in recent years. Crude oil exports represented 8.4 percent of the total monetary value of Canadian exports in 2006, a rise from 6.7 percent of the total in 2005.[12] Like the increased level of investment, the increased net exports raise prices and nominal GDP, eventually leading to a rise in interest rates. This increases demand abroad for Canadian dollar assets, raising the exchange rate. As the United States is a major trading partner, a C$/US$ exchange rate appreciation adversely affects all other areas of the economy due to the increased foreign cost of Canadian exports. When this sequence of events is triggered by an increase in energy production, it is called Dutch Disease, named for the deindustrialization experienced by the Netherlands at the beginning of North Sea energy resource extraction. Don Drummond, senior vice president and chief economist of TD Bank, said in March 2006 that "There's no doubt we have a mild case of Dutch disease running in Canada."[13] Given my above analysis, I am inclined to agree with this diagnosis, but it should be mentioned that a 2006 International Monetary Fund working paper offered a contrary opinion – that there was no measurable effect of natural resource exports on manufacturing. Instead, the report concluded that manufacturing was largely dependent on the U.S. economy.[14] Although the effects of the oil sands on other industries across Canada may be debatable, it is certain that industries in Alberta are experiencing higher capital and labor costs because of increased development in the Fort McMurray region.

Recognizing the impact of the development of the oil sands, Former Prime Minster Jean Chrétien said in 2001, "we have to make sure that every person in every part of Canada benefits from the potential and the wealth that belongs to the people of Canada."[15] Pronouncements from the federal government such as these make Albertans worry about possible federal involvement in the oil sands. While Alberta has always been wary of the federal government encroaching upon its jurisdiction over resources, this issue has become increasingly prominent with the continued growth of the oil sands. Despite the 2006 election of Stephen Harper, a Conservative Party member from Alberta, as Prime Minister of Canada, Alberta has maintained its distance from the federal government, as the province has several unique economic advantages that it would wish to protect from federal intervention. Alberta has a flat and relatively low provincial income tax rate, no sales tax, low corporate taxes, a budget surplus, no provincial government debt, rapid population and economic growth, and a large trust fund to secure dividends for future generations of Albertans. With Canada's history of confederation and redistribution of wealth between the provinces, Alberta and the oil sands industry is suspicious of any changes in federal tax policy that would extract more revenue from the oil sands. Any future policies that attempt to address the consequences of oil sands growth must account for the inherent differences in economic structures between Alberta and Canada.

5.3 Provincial Royalties

The oil sands industry is equally wary of any changes to provincial royalties that would decrease profits from bitumen and synthetic crude oil production. The current royalty regime, established in 1996 in order to spur investment in the oil sands, has come under attack for being too generous to oil sands companies. Critics claim that Alberta is not collecting a efficient portion of economic rent, leading to the owners of the resource – the people, as represented by the Alberta government – being inadequately compensated for the development of the oil sands. The argument continues to say that not only has this encouraged overproduction and too much construction through excessive profits, but also that it has led to the Alberta and Canadian government capturing a suboptimal amount of revenue. [16] The current provincial royalty regime is:

> "…a minimum 1% royalty payable on all production (gross revenue), royalty on production equivalent to 25% of net project revenues after the developer has recovered all project costs (100% of capital, operating, and research and development, in the year incurred) and a return allowance, the regime applies to new projects and expansions to existing projects, and companies can choose whether to pay royalties on bitumen or on more refined synthetic crude oil."[17]

While it must be noted that the oil sands have significantly higher upfront fixed capital costs than conventional oil facilities and therefore are subject to higher economic risks than other oil-producing projects, these terms of royalty agreements are extremely generous, as compared to the U.S. (which has a royalty of approximately 40 percent) or other countries (approximately 65 percent average). [18] The advantage of the Alberta system is that it creates a stable platform for investment, which in turn reduces risk for oil sands companies. Both Alberta and the federal government allow oil sands investors to essentially pay off their capital investment before paying any taxes or royalties through the regime and the accelerated capital cost allowance, respectively. This is significantly different than conventional oil operations, which only receive tax breaks on a quarter of their capital investment.[19] Because of this structure, cost increases on projects delay royalty payments, and therefore it is in the best interest of the government to ensure an efficient rate of development that minimizes budget overruns.

Such a strong economic situation, coupled with royalties from resource production, happens to enable the provincial government to provide its citizens with some of the best public services in Canada.[20] Alberta was predicted to collect a record

$13.2 billion from oil and gas royalties in the 2005/2006 fiscal year, accounting for over 40 percent of total provincial government revenue.[21] In fact, "for the first time, every Albertan received a $353 check from the provincial government [early in 2006] from an unexpected fiscal surplus."[22] The extent to which these royalties enable the provincial government to maintain low tax regimes is readily apparent with CAPP calculating that "Alberta would need at least a 25 per cent provincial sales tax to replace the revenue generated by the oil and gas industry."[23]

Despite Alberta's prosperity, the province may not even be capturing an efficient share of revenue from the oil sands. Pembina succinctly phrases the argument as such:

> "Between 1996 and 2005, world oil prices more than doubled and production of the oil sands, spurred on by federal subsidies and low provincial royalty rates, increased by 123%. Between 1997 and 2005, capital expenditure on oil sands development increased by over 300%, oil sands production increased 88% and the price of bitumen increased by 132%. In 1996, the Province received [$2.45] for each barrel of oil from the oil sands. In 2005, that figure was [23%] less at $1.89."[24]

Similarly, in a 2006 CAPP report, federal income tax revenue from the oil and gas sector is expected to fall from $4.5 billion in 2005 to $2.1 billion in 2008, despite increased production and increased market prices.[25] Therefore, it would appear that there is an inconsistency between increased corporate revenue and an expected increase in provincial royalties (see Figure 44). Alberta Premier Stelmach, has promised to review the royalty regime, but has given no indications as to when or whether it might be revised.[26]

Given that Alberta is not capturing an efficient share of revenue from the oil sands, the federal government may decide to levy taxes on production. In fact, in mid-March 2007, the federal government announced that it would begin to phase-out the

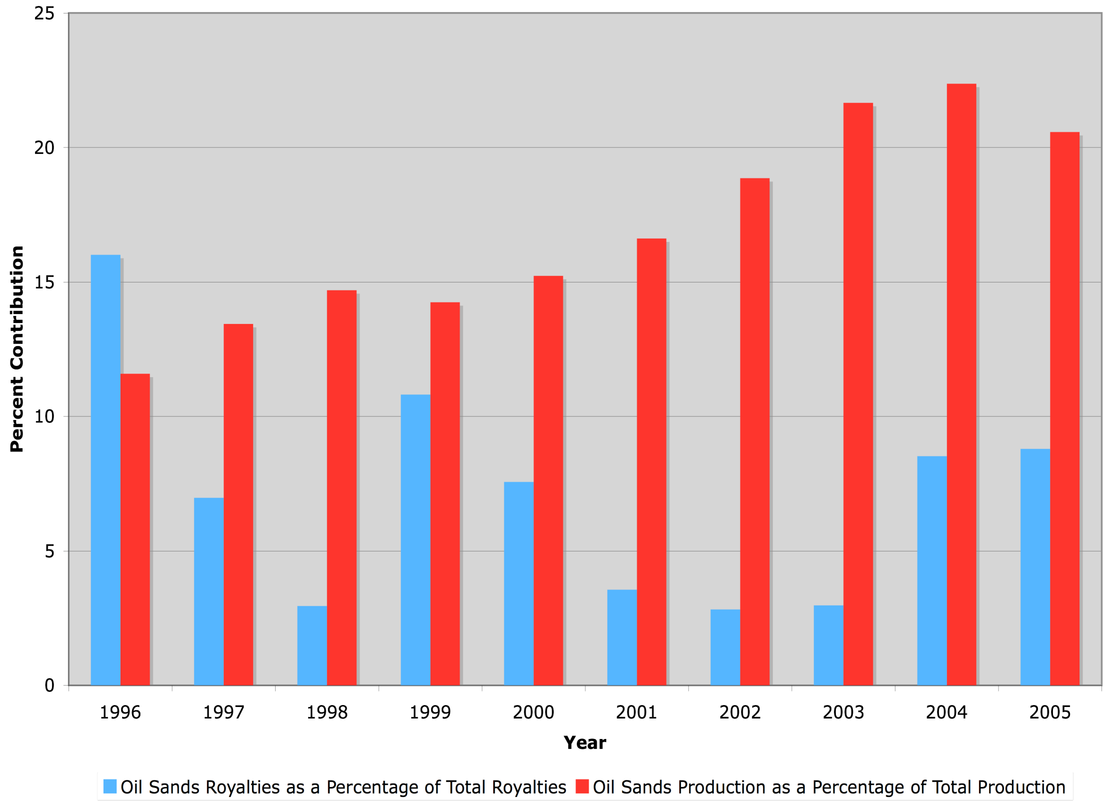


Figure 44. Contribution of Oil Sands to Alberta Oil and Gas Production and Royalties. Note production contribution increases and royalty contribution decreases. This is a result of a dilution effect caused by increases in natural gas royalties and oil sands expansion projects that have reduced royalty payments while their capital investment is written off. (Source: Pembina).

accelerated capital cost allowance tax, essentially a federal tax break on all capital expenditures before the beginning of production. While ending the tax break would have a minimal effect on operating costs, it compounds the uncertainty surrounding the policies of the provincial and federal governments towards the growth of the oil sands.[27] This increases the risk of reduced profits for new projects, which in turn decreases future investment and thereby potential growth.

5.4 Socioeconomic Issues

The oil sands boom has fueled rapid population and economic growth in Alberta for the past several years. For example, 5,000 of Alberta's 24,000 new jobs in January 2007 were associated with natural resource extraction. This is a sustained trend, with an employment growth rate of 14 percent per year in the natural resource extraction sector compared to a total province-wide employment growth rate of 6.5 percent per year (which in turn is over twice the Canadian average).[28] The result of this rapid employment growth is that one in seven Albertan jobs is linked to the oil and gas industry.[29] Therefore, a large percentage of Albertans directly feel the effects of oil sands growth, especially in Calgary and Fort McMurray.

Calgary, the commercial center of Alberta, is expected to grow 25 percent in the next decade, almost all of which is due to immigration. Adding sufficient housing and infrastructure for these 250,000 additional people in an already overheated economy will be a difficult task.[30] In 2005, approximately 70 people moved into Calgary each day, which greatly increased price pressures on the housing market. The resulting increase in real estate prices has ricocheted throughout the Calgary market, leaving Calgary with an office vacancy rate of approximately 0.5 percent, less than that of San Francisco during the internet boom. The cost of office space was $6-8 per square foot in 1994, $20 in 2004, and approximately $30 in 2005. Nevertheless, these real estate price increases are not unprecedented, as housing prices in Calgary during the 1970's energy-fueled economic growth shot up 400 percent during the 1970s energy-fueled economic growth spurt.[31] The rapid growth and associated price increases, however, have left many of Calgary's residents concerned about both the municipal infrastructure and the cost of living. The increase in real estate prices has contributed to negative socioeconomic impacts such as massive suburban sprawl and a 32 percent rise in homelessness from 2004 to 2006.[32] Despite the high land and construction costs, Calgary received a vote of confidence with EnCana announcing plans to build its new 59-storey office tower in downtown Calgary, which will be the tallest Canadian building west of Toronto.[33] These changes and growth pressures, however, pale in comparison to the challenges faced by Fort McMurray and the surrounding Municipality of Wood Buffalo.

As center of the Athabasca oil sands development, the population of Fort McMurray periodically experienced rapid growth in the past half century when there were waves of investment in the oil sands. Before Great Canadian Oil Sands began construction of the first commercial oil sands extraction plant in the 1960s, Fort McMurray's population stood at a mere 1,100.[34] By 1971, the town's population had risen to 6,000, and with the construction of Syncrude's operations, the population again rose, this time to 24,000 in 1978.[35] That same year, *Science* magazine reported that while both GCOS and Syncrude aided in building housing, there was abundant criticism for the dramatic increase in living expense, 'urban' sprawl, and lack of infrastructure – the same concerns voiced today.[36] The population of Fort McMurray was 35,200 before the present rapid rate of growth that began in 1996. The population, which currently stands at 61,000, is expected to increase to at least 70,000 by 2010.[37] Therefore, because of this growth, the provincial government should feel all the more obligated to mitigate the socioeconomic impacts of development and invest in the construction of municipal infrastructure.

Despite live-out allowances to workers who reside in rental homes in Fort McMurray and permanently live elsewhere, the oil sands boom has led to a drastic increase in housing costs. The average cost of a single family home has risen from approximately C$217,000 in 2004 to around C$414,000 in 2006.[38] The high housing costs have in turn led to a large shadow population of workers that numbered 11,779 in

2005, who are supported by Fort McMurray's infrastructure but do not have an official residence. [39] The growth of Fort McMurray has also had effects across Canada. As of 2006, approximately 11,000 Newfoundlanders live in Fort McMurray, having traveled almost 4,000 kilometers from their original homeland for higher paying jobs in the west. In Fort McMurray, Newfoundland flags are proudly displayed outside of many homes and are flown on the back of pickup trucks, as the Newfoundland community in Fort McMurray represents "the largest concentration outside of St. John's", the capital of Newfoundland. [40]

This rapid rate of growth has overtaxed Fort McMurray's infrastructure. The mayor of Fort McMurray, Melissa Blake, said in late 2006: "from the municipalities perspective, we are almost at the brink of financial incapacity. Basically our debt-borrowing is maxed out to the extent possible at this point [projected to be $232 million at the end of 2006], and we have an extensive amount of capital to deliver in the next five years."[41] In addition to physical infrastructure requirements, other essentials such as health services, have suffered from the rapid growth, as revealed by the fact that in 2006 the Municipality of Wood Buffalo had the lowest rate of patient satisfaction in the province, due to overstressed resources, according to the Health Quality Council of Alberta.[42] Given the revenue that the Albertan government receives from the oil sands royalties, it would seem appropriate for the province to return some of the money from its budget surplus to improve infrastructure in Fort McMurray. In late February 2007, the province announced $349 million worth of aid for infrastructure, which will be distributed to the town over the next three years. These funds, for health clinics, water treatment facilities, and affordable housing, are not nearly enough, as Fort McMurray believes it needs more than $880 million to match growing demand for municipal services.[43] Perhaps the announced provincial investment in Fort McMurray's infrastructure was in response to a November 2006 decision on planned oil sands expansion. In that decision, the Energy and Utilities Board wrote "that additional infrastructure investment in the Wood Buffalo region is needed, and it believes that there is a short window of opportunity to make these investments in parallel with continued oil sands development."[44]

Chapter 6 – Recommendations and Conclusion

6.1 Demand for Action

As illustrated in Chapter 1, the Energy and Utilities Board is correct to recognize this "short window of opportunity" for addressing the challenges generated by the growth of the oil sands. Public policy has the ability to change the course of oil sands development, but it needs the support of Albertans. In a study conducted in April 2006, the Pembina Institute interviewed a random and representative sample of 500 Albertan adults (with 95 percent confidence in a margin of error of ±4.4 percentage points) on a variety of environmental and economic issues about the oil sands. When asked if "the Government of Alberta should conduct a public review of oil sands royalties to ensure Albertans are getting the maximum possible benefit", 84 percent of the surveyed individuals agreed either "strongly" or "moderately".[1] From the response to this question, it is clear that Alberta must reevaluate the economic impact of the oil sands.

Albertans have similar concerns about the negative environmental impacts of oil sands development. In the same Pembina survey, when asked whether "oil sands companies can afford to be doing more to protect the environment," 87 percent of those surveyed responded in the affirmative. Even more (91 percent) individuals believed that "protecting the environment is important, even if it means oil sands development occurs more slowly." A similar percentage of the respondents (86 percent) believed that "in each of their oil sands plants, companies should be required to reduce greenhouse gas emissions that are responsible for climate change.[2] From these survey results, we can deduce that Albertans desire to see alternative environmental policies considered for the future.

It is important to note that Albertans are not alone in thinking that the environment is a serious issue that requires action. In January 2007, the *Globe and Mail* and CTV News, two of Canada's major nationwide media outlets, conducted a poll assessing Canadians' perceptions of climate change by surveying 1,000 Canadians (with 95 percent confidence in a margin of error of ±3 percentage points). The environment was seen by a plurality of Canadians as being "the most critical issue facing the country." When asked if "consumers or industry [are] to blame for most carbon emissions," 64 percent of poll respondents believed that "businesses and industries are more to blame."[3] The oil sands are not only one of the largest industrial emitters of greenhouse gases in Canada, but also one of the fastest growing sectors. Therefore, if policies affecting the oil sands were to be considered, it would seem that both Albertans and Canadians would support increased environmental regulation.

With similar sentiments existing both locally in Alberta and in Canada more generally, it is clear that there is a demand for action. In order to formulate efficient and effective policy, however, the intersection of the demand for action must be met with the supply of change from the government and industry.[4] First, as Chapters 1 and 2 illustrate, the oil sands are a unique resource that require complex technologies and large amounts of capital investment to extract bitumen and produce synthetic crude oil. The public, therefore, must understand that oil sands firms will necessarily have greater environmental impacts, as seen in Chapter 3, and high operating costs, as seen in Chapter 4, than conventional oil producers. Therefore, oil sands operators may need their exposure to environmental and economic risk reduced in order to make the resource profitable to develop. Second, the government and industry must recognize that the oil sands should not be shielded from policies intended to promote sustainable development. These policies, such as increased royalty rates or reduced tax breaks, may have the consequence of reducing investment or increasing climate change regulation. Third, both Canadians and interested individuals from the international community should be mindful of the fact that Alberta's political climate is unique in Canada, with a long-standing stable, conservative, and pro-business government. Finally, Alberta has long viewed its natural resources commodities that should be developed fully in order to promote economic growth. The high environmental and socioeconomic costs of oil sands development, however, may counteract some of these economic benefits.

6.2 Policy Directions

With increasing interest in the oil sands due to continued production growth, it is imperative for the public to decide how government and industry should approach the future of the oil sands. First, as seen in Chapters 2 and 4, the oil sands operators have vastly different extraction and production technologies and costs. Questions therefore arise whether policies can be implemented most effectively when focused on the firm (small vs. large plants), process (mining vs. in-situ facilities), or industry (existing vs. new firms). Second, Alberta and Canada generally use a consultative process for policy decisions. As a result, any environmental regulation would necessitate having both industry and other interested parties at the table. Third, oil sands operators are exposed to large economic risks and because of this, the oil sands industry prefers long-term regulation coupled with market rewards.[5] Therefore, effective oil sands public policy action must reconcile disparate agendas, encourage compliance while mitigating economic risks, and function at all operation levels. Two economists, Michael Porter and

Claas van der Linde, suggested in a controversial 1995 article about environmental regulation compliance and firm competition that "properly designed environmental standards can trigger innovation that may partially or more than fully offset the costs of complying with them…. By stimulating innovation, strict environmental regulations can actually enhance competitiveness…."[6] While Porter and van der Linde's hypothesis runs contrary to the economic tenet that there are no regulatory "free lunches," the hypothesis may hold in Alberta. The possibility exists as greenhouse gas emissions regulation could encourage oil sands operators to innovate technologies that reduce energy usage and consequently, reduce operating costs.[7] If this were to be case, the government would act as a trendsetter and regulatory coordinator. This would entail setting clear goals with flexible approaches, thereby actively seeding and spreading innovation via market and profit incentives.[8]

By introducing market mechanisms for more stringent environmental regulations, Alberta may be able to begin to reduce some of the growing environmental risks associated with the development of the oil sands. These risks, such as the expansive tailings ponds, large land disturbances, lack of reclamation, and increased greenhouse gas emissions can be considered "megahazards" that will affect everyone in the province.[9] Peter Lougheed, a former Alberta Premier during the 1970s energy boom and a respected Albertan statesman, recommended in October 2006 that the government should undertake a "new policy direction" and a "more measured approach" in order to reduce the environmental and economic risks associated with the growth of the oil sands.[10] Former Premier Lougheed's comments suggest that future oil sands development should proceed with precaution. Alberta Environment has largely adopted a wait-and-see approach to oil sands regulation on the basis that there is not enough conclusive research to formulate appropriate risk-based environmental policies. In contrast, it is my view that policies should be set in place now, as the environmental risks of continued growth may be so large that the full impact may not be known for some time, possibly until after it is too late to avert the environmental degradation.[11] This concept is embodied in the precautionary principle, which is based on the belief that the state should strive to avoid environmental damage. In order to deal effectively with the new, large-scale issues of oil sands development, Alberta will need a paradigm shift from the mitigation to the prevention of the negative consequences of growth.[12]

The reduction of environmental risks associated with oil sands production serves the best interests of the government, industry, and public. In order to resolve these long-term uncertainties, more research should be conducted on water, land, and air impacts, more funding ought to be allocated for oversight bodies, and stakeholder groups should be strengthened so as to better represent concerns with development. In the short-term, perhaps it is best to proceed according to the precautionary principle. The Pembina Institute, in its paper on the consequences of in-situ development, *Death By a Thousand Cuts,* essentially encouraged a precautionary approach to addressing cumulative environmental impacts. The recommendations included: developing a regional protection plan for the boreal forest, formulating limits on cumulative industrial disturbances, facilitating integrated land management, and establishing industrial best practices. While the Pembina study was generally very perceptive, the Institute's suggestion to include protecting areas of the boreal forest that are devoid of oil sands is an ineffective conservation strategy, as these tracts of land would be undisturbed due to the industry's lack of an incentive to develop on these leases.[13] Instead, I suggest that the province reconsider its oil sands lease tenure system, which provides a financial incentive for companies to develop their marginal leases rather than leave them fallow.[14] This policy encourages increased production, which may run contrary to Alberta's interests, as examined in Chapters 4 and 5. Encouraging the oil sands industry to take a measured and sequential approach to lease development will reduce pecuniary costs for the oil sands industry and reduce overall capital and operating costs for all oil sands firms.

Shifting the focus to recommendations for the long-term, the organizations that represent the interests of Albertans in the oil sands interact neither efficiently nor effectively. Current issues within the oil sands academic and policy communities can be broken down into three groups: the role of research, the role of environmental NGOs, and the role of the government. With Alberta's stable, conservative government, any changes to the current pattern of development will most likely originate from stakeholder discussion, which will increase the probability of shared ownership in policy changes.

First, the opportunity to do academic research on the oil sands is severely limited by the lack of available data. Much of the data are confidential, protected by the oil sands firms, and what statistics are available are frequently limited in scope.[15] Even those resources that should be available are not readily accessible. Industry points to the existence of the Oil Sands Environmental Research Network (OSERN) and the Canadian Oil Sands Network for Research and Development (CONRAD), which were supposed to promote data sharing amongst the academic community. While these organizations may have been active in the past, OSERN's website appears to have ceased functioning.[16] Despite claiming to have updated its website on November 10, 2006, CONRAD's newsletter has not been updated since 2002.[17] It is impossible not to look at the fate of these organizations as emblematic of the condition of collaborative academic research on the oil sands.

Second, environmental NGOs and independent consultants are attempting both to conduct research and to advocate certain policy actions. This creates confusion about their agendas. The Pembina Institute described the importance of coupling with industry as fulfilling a "need for utility." This comment suggests that research on the environmental impacts of the oil sands must answer a specific policy question that has been conceived by industry, an opinion seconded by the Canadian Energy Research Institute.[18] This belief may be due to the fact that a portion of Pembina's funding comes from the industry sources, as Pembina receives revenue from fee-for-service contracts with oil sands firms. In addition, the top four sponsors of Pembina's Annual Earth Celebration Gala were Petro-Canada, EnCana, Shell Canada, and Suncor Energy, all of which are oil sands operators.[19] Similarly, CERI has evolved from an independent research institute into an industry and government consultant, hired for its research abilities.[20] While one cannot conclude that the industry controls the agendas of these organizations, its significant financial contributions may influence how the issues are presented to the public.

Third, despite unprecedented government revenues, Alberta Environment appears to be under-resourced, especially when compared to the environmental challenges facing the province.[21] According to the *Edmonton Journal*, "the budget of Alberta Environment has not kept pace with the booming development it's supposed to monitor in northern Alberta. That budget is smaller…than that of the environment department in

Saskatchewan, a smaller province [with less than half the population of Alberta and] facing fewer environmental challenges."[22] Further highlighting Alberta Environment's difficult task to formulate effective policy, until recently, the ministry did not have precise statistics on the breakdown of oil sands water usage. The Energy and Utilities Board audits all purchases and sales of oil, gas, and water in the oil sands facilities, but because of its proprietary data format, these statistics cannot be easily shared with Alberta Environment.[23] The data-sharing problem is compounded by the fact that Alberta Environment collects all its oil sands data once a year in a paper format, rather than more frequently through an electronic system. There are plans to convert to a quarterly digital reporting method, but this move will not be complete for some time. Alberta Environment hopes that the new system will enhance monitoring that will enable the formulation of new policies such as seasonal and adaptive water management. [24] While one may think that the federal government may be able to aid in coordination between ministries, the Alberta government and oil sands industry are deeply concerned about, if not outright hostile to, the federal government's increasing level of interest in the oil sands.[25] As greenhouse gas emissions are linked to the production of synthetic crude oil from the oil sands, some believe that federal regulations may lead to backdoor control of provincial resources by the federal government.[26] Despite Alberta's fears, I would recommend that greenhouse gas emissions policy be coordinated at the federal level. Currently, Alberta and Canada are formulating different regulations and market incentives to reduce greenhouse gas emissions. These policies should be harmonious to avoid market niches that complicate industry compliance and targets should be carefully considered and not set in response to political pressure. On the other hand, for other environmental issues, such as managing water, land, and air impacts, I would agree with Alberta Environment that the province is best equipped to face these local and regional environmental challenges associated with the oil sands. This is because these environmental impacts directly affect the provincial government's constituents. Therefore, in order formulate effective policy, Alberta Environment should canvass Albertans views of current and future development in an attempt to scientifically and economically evaluate the environmental impacts of the oil sands.

6.3 Evaluating Impacts

Many of the challenges facing the oil sands are simply a result of too much development in too short a time, with neither the environment nor the economy able to keep pace. Currently, there is no regional landscape plan to ensure sustainable development, nor is there a body that is capable of slowing the pace of development to reduce the socioeconomic impacts. The body that does have regulatory control over the approval of oil sands projects, the Energy and Utilities Board, wrote in its fall 2006 approval of the Athabasca Oil Sands Project that "the [panel] does not believe that the EUB has the mandate to resolve the socioeconomic issues raised in this proceeding; rather it believes that responsibility rests with appropriate government bodies that are in a position to provide direct assistance in these matters."[27] It seems that provincial ministries are equally unwilling to decide how the development of oil sands should proceed. Alberta Energy equates good management with reaching 4 million barrels per day by 2020; the consequences of growth are not a major part of the ministry's calculus.[28] In comparison, Alberta Environment is still in the process of determining what goals it should pursue for oil sands development.[29]

Although several studies have looked at the benefits of increased oil sands production, no studies have analyzed the aggregate environmental costs of this production. Measuring the cost of the environmental changes related to the growth of the oil sands is particularly challenging, as the resident population in the oil sands region is relatively small, but the indirectly affected population across Alberta is, by comparison, quite large. Perhaps the best way to approach an alternative future for the oil sands would be to estimate the benefits of increased environmental regulation. In order to assess these benefits, an economist would need to employ a non-use valuation study such as contingent valuation. Contingent valuation is an accepted method for this purpose in several United States federal regulatory departments and has been used in a number of high profile cases, such as after the *Exxon Valdez* oil spill in Prince William Sound, Alaska. There is still significant debate in the economics literature as to whether contingent valuation actually measures an individual's willingness to pay for an improvement in environmental quality, or whether the survey method merely generates an artificial quantity based on the individual's biases.[30] Nevertheless, Alberta's environmental NGOs, industry, and government may be particularly receptive to a contingent valuation study, given the province's openness to the market system for decision-making. A survey of the oil sands would include initial questions about perceptions of public goods like the environment and general knowledge of the oil sands, a description of the oil sands region including photographs and development maps, a description of the impacted ecosystem, an explanation of a possible policy solution, and finally valuation questions.[31] In order to evaluate an individual's willingness to pay for increased environmental regulation, the survey must define a payment mechanism, such as a one-time tax payment. With Alberta reconsidering its royalty regime, this is an ideal moment for the public to consider how it would support more stringent environmental regulations. Survey participants might be asked whether they would agree to pay a certain amount of money to the province if the oil sands industry's royalty rates increased by a certain percentage, albeit with a full description of potential economic impacts. Prospective policies could recommend additional reclamation funds, additional tailings ponds remediation efforts, new pollution regulations and monitoring, or a provincial program to mitigate greenhouse gas emissions. The opportunity to evaluate the social and environmental costs of the oil sands will allow for informed, economically efficient policy decisions that will help chart a new course of development in the oil sands.

6.4 Alternative Greenhouse Gas Emissions Futures

As discussed earlier, both the provincial and the federal governments are currently setting greenhouse gas emissions targets, which may affect the growth of the oil sands. As demonstrated in Chapter 5, the oil sands are a significant economic force in Alberta and Canada, and as such, policymakers should not consider absolute emissions reductions or emission intensity reductions without understanding how the oil sands industry may be able to meet these targets. Taking inspiration from a 2004 *Science* article by Princeton University Professors Stephen Pacala and Robert Socolow entitled "Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Current Technologies", I have undertaken a similar hypothetical exercise to illustrate an alternative future for the oil sands industry. Pacala and Socolow's 2004 article was based on attempts to mitigate 50 years of business-as-usual greenhouse gas emissions from global energy production via a number of scaled-up proven technologies. Thus, an increase in emissions from

2004 to 2054 of 7 billion tons of carbon per year to 14 billion tons of carbon per year would be stabilized by seven wedges, each representing 125 billion tons of total carbon emission reduction in the 50 year span.[32]

I believe Pacala and Socolow's analytical process can be scaled down and applied to the oil sands (see Figure 45). I have chosen to give the industry a three-year preparatory period before establishing a base-line of greenhouse gas emissions in 2010. From 2010 to 2020, ten wedges represent options to reduce greenhouse gas emissions by ten percent each. According to CERI's projection, which will be considered business-as-

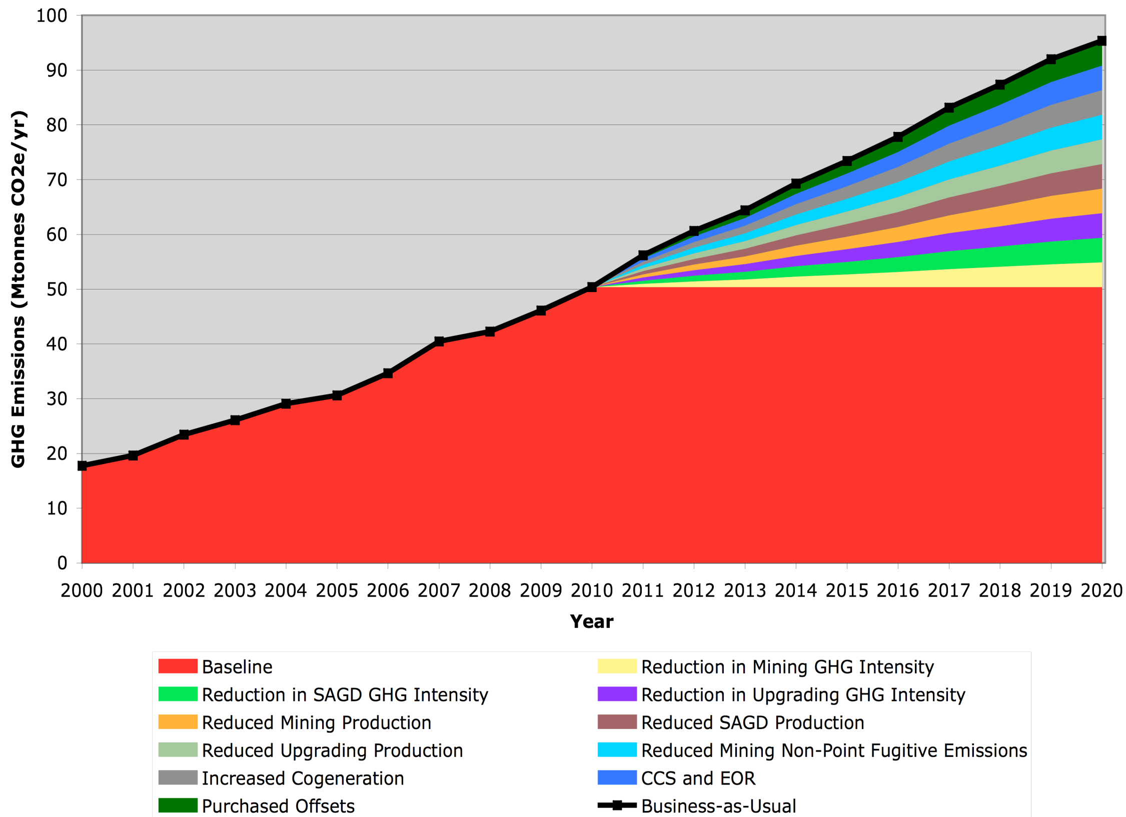


Figure 45. Scenarios for Greenhouse Gas Emission Reduction from Business-As-Usual. Each wedge represents a possible 10 percent reduction in business-as-usual emissions in 2020 from a baseline of emissions in 2010. The resulting wedge amounts to a total reduction of 22.5 million tons of carbon dioxide equivalent over the 10 year period. Note that when some of these wedges are combined there are interactions that may decrease the amount of the reduction.
(Source: CERI, Pembina, worldenergy.org, NEB)

Table for Scenarios for Greenhouse Gas Emission Reduction from Business-As-Usual		
Option/Scenario	**Description**	**Comments**
Reduction in Mining GHG Intensity	Reduce to approx. 29kgCO2e/bbl bitumen	Approx. 17 percent reduction in Mining GHG intensity
Reduction in SAGD GHG Intensity	Reduce to approx. 47kgCO2e/bbl bitumen	Approx. 15 percent reduction in SAGD GHG intensity
Reduction in Upgrading GHG Intensity	Reduce to approx. 40kgCO2e/bbl SCO	Approx. 11 percent reduction in Upgrading GHG intensity
Reduced Mining Production	Reduce to 1.8 million barrels/day of bitumen in 2020	Approx. 17 percent decrease in expected production
Reduced SAGD Production	Reduce to 1.2 million barrels/day of bitumen in 2020	Approx. 15 percent decrease in expected production
Reduced Upgrading Production	Reduce to 2.1 million barrels/day of SCO in 2020	Approx. 12 percent decrease in expected production
Reduced Mining Non-Point Fugitive Emissions	Reduce to approx. 7.5kgCO2e/bbl bitumen	Approx. 45 percent reduction in Mining Non-Point Fugitive Emissions
Increased Cogeneration	1060MW Cogeneration Capacity Producing 7900 GWh per year by 2020 (85 percent peak capacity)	Approx. 33 percent of expected total capacity, approx. 70 percent increase in expected sales to grid
Carbon Capture, Enhanced Oil Recovery, and Sequestration (CCS and EOR)	Up to 4.5 million tons carbon dioxide per year by 2020	See following paragraphs about Integrated Carbon Dioxide Network
Purchased Offsets	Cost $67.5 million per year by 2020 ($338 million cumulative)	Assuming $15/ton CO2e offset as under Kyoto (Price used by industry to calculate credit costs in early 2000s)

usual, greenhouse gas emissions are predicted to increase from 50.4 million tons of carbon dioxide equivalent to 95.3 million tons of carbon dioxide equivalent. Therefore, both the Pacala and Socolow calculation and my scenario involve a doubling of greenhouse gas emissions, but the oil sands emissions growth will occur in only one-fifth the time. Despite the much shorter time period, I believe that the rapid technological change in the oil sands and frequent investments that retrofit old capital equipment will make some or most stabilization wedges able to be accomplished with only slight innovations in current technology. Oil sands firms have a significant financial incentive to reduce energy consumption, and thereby reduce greenhouse gas emissions. As demonstrated in this example, there are several viable methods for the oil sands industry to alter the business-as-usual greenhouse gas emissions curve.

My strategies for greenhouse gas emissions reduction include decreased greenhouse gas intensities; reduced production due to high capital costs; reduced fugitive non-point emissions (from sources such as tailings ponds); increased cogeneration; carbon capture, enhanced oil recovery, and sequestration; and purchased offsets (see Table for Figure 45). While some of these scenarios are more probable or conducive to industry participation than other options, all are feasible areas of greenhouse gas emissions reductions in a decade. For example, as described in Chapter 2, Shell Canada recently announced a new technology for froth treatment that reduces energy requirements, and therefore greenhouse gas emissions, by 10 percent.[33] If another, similar, technological innovation was able reduce greenhouse gas emissions intensity by 7 percent, overall emissions from the oil sands would fall by 10 percent. Therefore, while dependent on minor technological improvements, some of these scenarios would be realistic goals for the near future. In contrast, Pembina explored a vastly more hypothetical alternative future, undertaking a report that investigated the cost of making the oil sands carbon neutral by 2020 (thus eliminating all ten wedges and the baseline 2010 emissions from the Figure 45). Using a combination of purchased offsets (ranging in price from \$22 to \$66 per ton of carbon dioxide equivalent, CO_2e) and carbon capture and sequestration (ranging in cost from \$34 to \$100 per ton of CO_2e), the report indicated that the cost of making the oil sands carbon neutral could range from \$1.76 to \$13.65 per barrel.[34] Although this is an enormous range of prices, especially compared to existing operating costs, it is nonetheless an interesting investigation of potential opportunities for sustainable development.

The challenges ahead are considerable, but environmental NGOs, government agencies, and oil sands firms have recognized the need to articulate alternative futures. In a August 2006 interview, Dr. Soheil Asgarpour, oil sands Business Leader for Alberta Energy, emphasized that his ministry is currently transforming its focus from directing oil production to capturing more of the energy and petrochemical value chain in Alberta by building world-class upgrading and refining projects.[35] Although the opportunities and challenges associated with this hydrocarbon upgrading initiative were discussed in Chapter 4, a visionary aspect of the plan deserves special attention.

The Integrated Carbon Dioxide Network (ICO_2N) is a joint proposal between government and industry to capture CO_2 from industrial facilities in the oil sands and around Edmonton. The gas would then be transported via pipeline to a distribution facility outside of Edmonton, and then used in aging central Alberta oilfields for enhanced oil recovery projects. Firms that are interested in the project span much of the oil and petrochemical industry, including Enbridge (a large pipeline operating firm), Suncor, Air Products Canada, Nexen, Shell Canada, Canadian Natural Resources, ConocoPhillips, Syncrude, TransAlta (an energy utility), and Imperial Oil. This project would be expensive and would face inflated labor and construction costs. While costs for pipeline construction are estimated to be \$1.76 billion and the expense for capture and injection facilities twice that amount, some project costs would be recouped from revenue generated via enhanced oil recovery.[36] Sustaining production in these aging oilfields would require up to 11,500 tons of CO_2 daily, which is roughly equivalent to the amount of 98 percent pure CO_2 effluent produced by the oil industry today.[37] These CO_2 injections would boost oilfield recovery rates by up to 40 percent, with eventually 200 to 300 million tons of carbon dioxide sequestered into the Western Canadian Sedimentary Basin.[38]

While still undergoing research, sequestration is a field-tested technology. According to *IPCC Special Report: Carbon Dioxide Capture and Storage*, there are three sequestration projects processing approximately 2,700 tons of CO_2 daily – Sleipner (Norway), Weyburn (Saskatchewan, Canada), and In Salah (Algeria). In their lifetimes, they will be storing 20 million tons of CO_2, 20 million tons of CO_2, and 17 million tons of CO_2 respectively. In comparison, Alberta's ICO_2N project is of an unprecedented scale, with five times the sequestration rate and over ten times the final reservoir size as in the Sleipner, Weyburn, and In Salah projects. Therefore, both engineering and financing the project will be extremely challenging. The benefits of ICO_2N, however, go far beyond the revenue associated with additional oil recovery. Oil companies may benefit by earning offset credits or reduced provincial royalties through supplying the project with CO_2, and the Alberta energy industry will pioneer sequestration technologies, potentially gaining a first mover advantage in the global climate change mitigation marketplace.[39]

6.5 Conclusion

The development of the Athabasca oil sands is an unprecedented challenge, opportunity, and experiment. EnCana's executive vice-chairman aptly stated in March 2006 "we're a big laboratory in how to absorb so much investment. None of us could have dreamed this would happen this quickly."[40] The risks and challenges facing development are significant, especially with regards to water, capital expenditure, and greenhouse gas emissions. The outgoing chairman of the Energy and Utilities Board said in January 2007 that he

> "was amazed at the depth and the extent of the [oil sands] development going on. The question in [his] mind is, are [Albertans] in the same position regarding the oilsands today as regulators were in the early 1930s when the board was formed to look at [the development in the] Turner Valley [the first major conventional oil field in Alberta]? We've got a whole new energy development that I'm sure wasn't anticipated even five years ago."[41]

Despite the vast scale of the oil sands, the reader must remember that this is just one small part of the energy equation. While conducting an interview at Pembina, there was great interest as to whether the oil sands would be a viable project in the U.S. or whether there was something unique about the Alberta resource investment and development climate.[42] I would argue that there is nothing unique about Alberta, and that is precisely why we should be concerned for the future of both non-conventional and hydrocarbon resource extraction in general. Energy-based mining is taking place in the U.S., whether as strip mining in Wyoming or mountaintop-removal mining in West Virginia. These two locations along with the oil sands will share similarly difficult legacies. Wyoming alone is projected to have 103,600 square kilometers of reclaimed coal mines by 2020.[43] This scale of reclamation, however, may pale in comparison to potential future developments of oil shale in Colorado. On the other hand, in-situ development's disruption of the boreal forest ecosystem may be an unfortunate precedent to oil development in the Arctic National Wildlife Refuge. The oil sands may be a harbinger of the environmental effects of these ongoing and future energy projects.

Time will be the arbiter of whether environmental NGOs, industry, and government succeeded in solving the challenges facing the development of the Athabasca oil sands. Witnessing the power of time, I hiked through Syncrude's twenty-year-old forested reclamation project in August 2006. Arriving at an observation platform that emerged above the treetops, I looked out on the devastation to the landscape caused by the mining of bitumen from the oil sands (see Figure 46). Industrial activity had replaced hundreds of square kilometers of boreal forest with a wasteland dotted with sand piles, tailing ponds, refineries, and earth-moving equipment. The stench of sulfur-laden bitumen hung in the air, and likewise, the uncertain prospects of reclamation hang over the oil sands. Nonetheless, with ingenuity, perseverance, and a focus on sustainable development, Alberta will be able to take full advantage of the opportunities presented by the Athabasca oil sands.

Figure 46. Syncrude Reclamation, Tailings Ponds, and Plant Site from reclamation site observation platform. Reproduced from Chapter 3. (MTW, 20 August 2006)

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