National Energy Board

Office national de l'énergie

Canada's Oil Sands

OPPORTUNITIES AND CHALLENGES TO 2015: AN UPDATE

AN ENERGY MARKET ASSESSMENT JUNE 2006

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FIGURES

TABLES

AENV	Alberta Environment
AESO	Alberta Electric System Operator
ANS	Alaskan North Slope
CBM	coal bed methane
CEMA	Cumulative Environmental Management Association
CERI	Canadian Energy Research Institute
CHOPS	Cold Heavy Oil Production with Sand
CHP	Combined Heat and Power
CONRAD	Canadian Oilsands Network for Research and Development
CSS	Cyclic Steam Stimulation
EMA	Energy Market Assessment
EOR	enhanced oil recovery
EUB	Alberta Energy and Utilities Board
GDP	Gross Domestic Product
GHG	greenhouse gases
LLB	Lloydminster Blend
MSAR	Mulitphase Superfine Atomized Residue
MSW	Mixed Sweet (crude oil)
NEB	National Energy Board
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
PADD	Petroleum Administration for Defense District
RAS	Remedial Action Schemes
RIWG	Regional Issues Working Group
SAGD	Steam Assisted Gravity Drainage
SCO	synthetic crude oil
SGL	synthetic gas liquids
SOR	steam-to-oil ratio
THAI	Toe-to-Heel Air Injection
U.S.	United States
VAPEX	Vapour Extraction Process
VGO	vacuum gas oil
WBEA	Wood Buffalo Environmental Association
WCS	Western Canadian Select
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

Units

b	barrel(s)
b/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Btu	British thermal units
Btu/cf	British thermal unit per cubic feet
cf	cubic feet
GW	gigawatt
GW.h	gigawatt hour
m^3	cubic metres
m^3/d	cubic metres per day
Mcf	thousand cubic feet
Mb/d	thousand barrels per day
MMb	million barrels
MMb/d	million barrels per day
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MW	megawatt
scf	standard cubic feet

Foreword

The National Energy Board (the NEB or the Board) is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines as well as international and designated interprovincial power lines. The Board regulates pipeline tolls and tariffs for pipelines under its jurisdiction. In terms of specific energy commodities, the Board regulates the exports and imports of natural gas as well as exports of oil, natural gas liquids (NGLs) and electricity. Additionally, the Board regulates oil and gas exploration, development and production in Frontier lands and offshore areas not covered by provincial or federal management agreements. The Board's advisory function requires keeping under review matters over which Parliament has jurisdiction relating to all aspects of energy supply, transmission and disposal of energy in and outside Canada.

The NEB collects and analyzes information about Canadian energy markets through regulatory processes and market monitoring. From these efforts, the Board produces publications, statistical reports and speeches that address various market aspects of Canada's energy commodities. The Energy Market Assessment (EMA) reports published by the Board provide analyses of the major energy commodities. Through these EMAs, Canadians are informed about the outlook for energy supplies in order to develop an understanding of the issues underlying energy-related decisions. In addition, policy makers are informed of the regulatory and related energy issues. On this note, the Board has received feedback from a wide range of energy market participants across the country indicating that the NEB has an important role and is in a unique position to provide objective, unbiased information to federal and provincial policy makers.

This EMA is an update to a previous oil sands EMA released by the Board in May 2004, entitled *Canada's Oil Sands: Opportunities and Challenges to 2015*. Audiences requiring a detailed review of the background surrounding the oil sands resource and its development are encouraged to read the previous publication. The key objective of this report is to highlight the major changes to the supply and market analysis resulting from developments in the last two years.

In preparing this report, the NEB conducted a series of informal meetings and discussions with a cross-section of oil sands stakeholders including producers, refiners, marketers, pipeline companies, electricity and petrochemical officials, industry associations, consultants, government departments and agencies, and environmental groups. The NEB appreciates the information and comments provided and would like to thank all participants for their time and expertise.

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

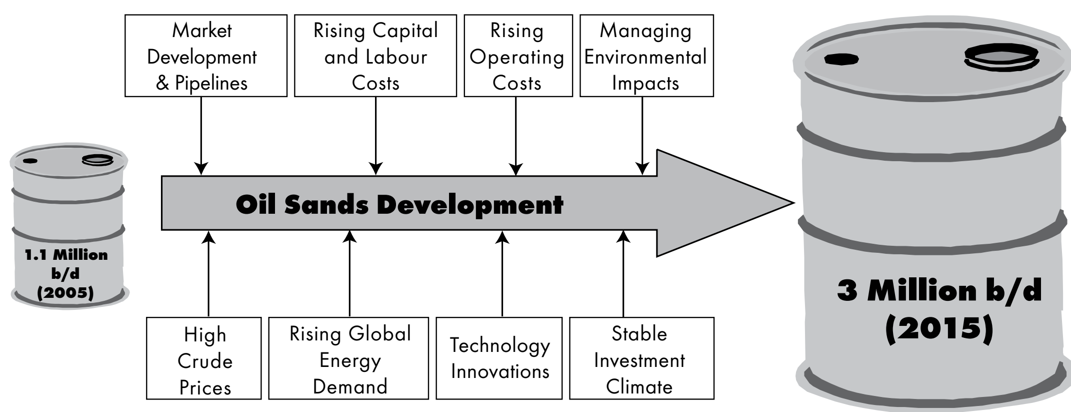
EXECUTIVE SUMMARY

Introduction

In May 2004, the Board released an Energy Market Assessment (EMA) entitled *Canada's Oil Sands: Opportunities and Challenges to 2015*, which contained detailed discussions on the major aspects of the oil sands industry and assessed the opportunities and challenges facing the development of the resource. Since then, the conditions surrounding oil sands development have changed significantly. As a result, the Board decided to provide an update to this report, highlighting major changes and developments.

The diagram below shows the major influences on oil sands development as production grows from 175 000 m^3/d (1.1 MMb/d) in 2005 to a projected 472 000 m^3/d (3.0 MMb/d) by 2015.

Influences on Oil Sands Development



A comparison of key assumptions between the current analysis (2005 dollars) and the 2004 report (2003 dollars) is as follows:

Assumptions	**June 2006 Report**	**May 2004 Report**
WTI crude oil price	US$50 per barrel	US$24 per barrel
NYMEX natural gas price	US$7.50 per MMBtu	US$4.00 per MMBtu
Light/heavy price differential	US$15 per barrel	US$7 per barrel
Canadian dollar exchange rate	US$0.85	US$0.75

Key Findings

Supply Costs

The table below provides estimates of operating and supply costs for various types of oil sands recovery methods.

Estimated Operating and Supply Costs by Recovery Type

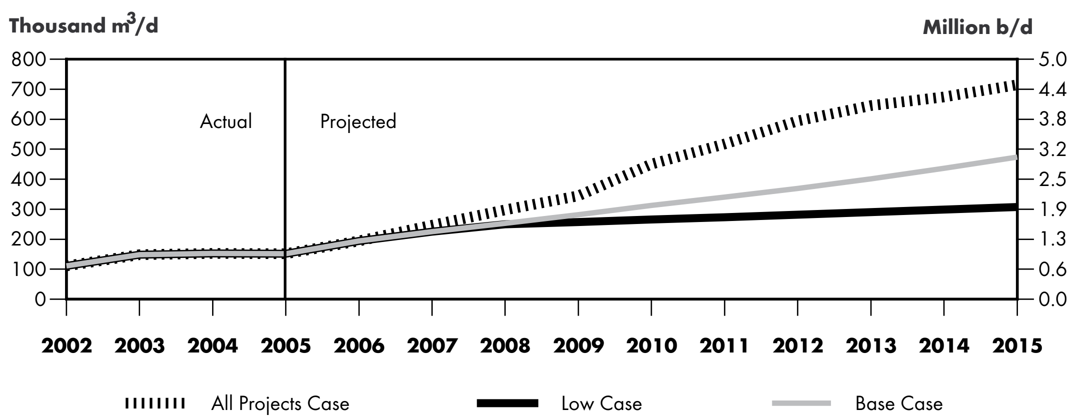
C$(2005) per barrel at the Plant Gate	Crude Type	Operating Cost	Supply Cost
Cold Production – Wabasca, Seal	Bitumen	6 to 9	14 to 18
Cold Heavy Oil Production with Sand (CHOPS) – Cold Lake	Bitumen	8 to 10	16 to 19
Cyclic Steam Stimulation (CSS)	Bitumen	10 to 14	20 to 24
Steam Assisted Gravity Drainage (SAGD)	Bitumen	10 to 14	18 to 22
Mining/Extraction	Bitumen	9 to 12	18 to 20
Integrated Mining/Upgrading	Synthetic	18 to 22	36 to 40

Integrated mining and SAGD operations are estimated to be economic at US$30 to $35 per barrel WTI. Continued escalation in material and labour costs pose a risk to this outlook. Higher natural gas prices and blending costs would also increase this estimate. On the other hand, advancement in recovery and upgrading technologies hold potential to reduce supply costs.

Crude Oil Supply

About C$125 billion in capital expenditures have been publicly announced for the period 2006 to 2015; however, it is unlikely that all publicly announced development plans will be completed in the declared timeframe. The Base Case projection, shown in the chart below, assumes capital expenditures of C$94 billion and indicates oil sands production will almost triple from 175 000 m^3/d (1.1 MMb/d) in 2005 to 472 000 m^3/d (3.0 MMb/d) by 2015.

Projected Total Bitumen Production



Markets and Pipelines

Based on industry consultations and the Board's internal analysis, potential scenarios for market expansion for the growing oil sands production could unfold as outlined in the following table.

Potential Markets for Oil Sands Production

Steps	Potential Markets
1	Existing core markets in Ontario, Western Canada, northern PADD II (see map in Introduction, page 1), PADD IV and Washington State
2	Southern PADD II, PADD III, new cokers and/or refinery expansions in PADDs II, IV and V
3	New markets in California and the Far East

With increasing production from the oil sands, total pipeline capacity out of the Western Canada Sedimentary Basin (WCSB) could be near full utilization starting in 2007. The pace of pipeline expansion will depend on decisions with respect to the markets to be served and the necessary regulatory approvals.

Environmental and Socio-economic Impacts

There is now a clearer understanding that large water withdrawals from the Athabasca River for mining operations during the winter could impact the ecological sustainability of the river. As well, it is uncertain if land reclamation methods currently employed will be successful. These issues have moved to the forefront of environmental concerns. Regions associated with oil sands development enjoy several economic benefits but at costs to the social well-being of the communities, including a shortage of available housing and stress on public infrastructure and services. There is currently a limited supply of skilled workers in Alberta, and this tight labour market is expected to continue in the near future.

Electricity and Petrochemical Opportunities

The potential for building cogeneration capacity has decreased somewhat since the 2004 report. The recent trend has been for oil sands producers to build for self-sufficiency with little excess electricity generated for sale to the grid. However, factors that could alter the trend include: advancement in gasification technology that could reduce the reliance on natural gas for fuel; access to a higher priced electricity market; and a premium payment for clean power.

Given the outlook for synthetic crude oil production, the Alberta petrochemical industry may have an opportunity to supplement declining ethane feedstock supply with synthetic gas liquids extracted from upgrader off-gas.

Outlook

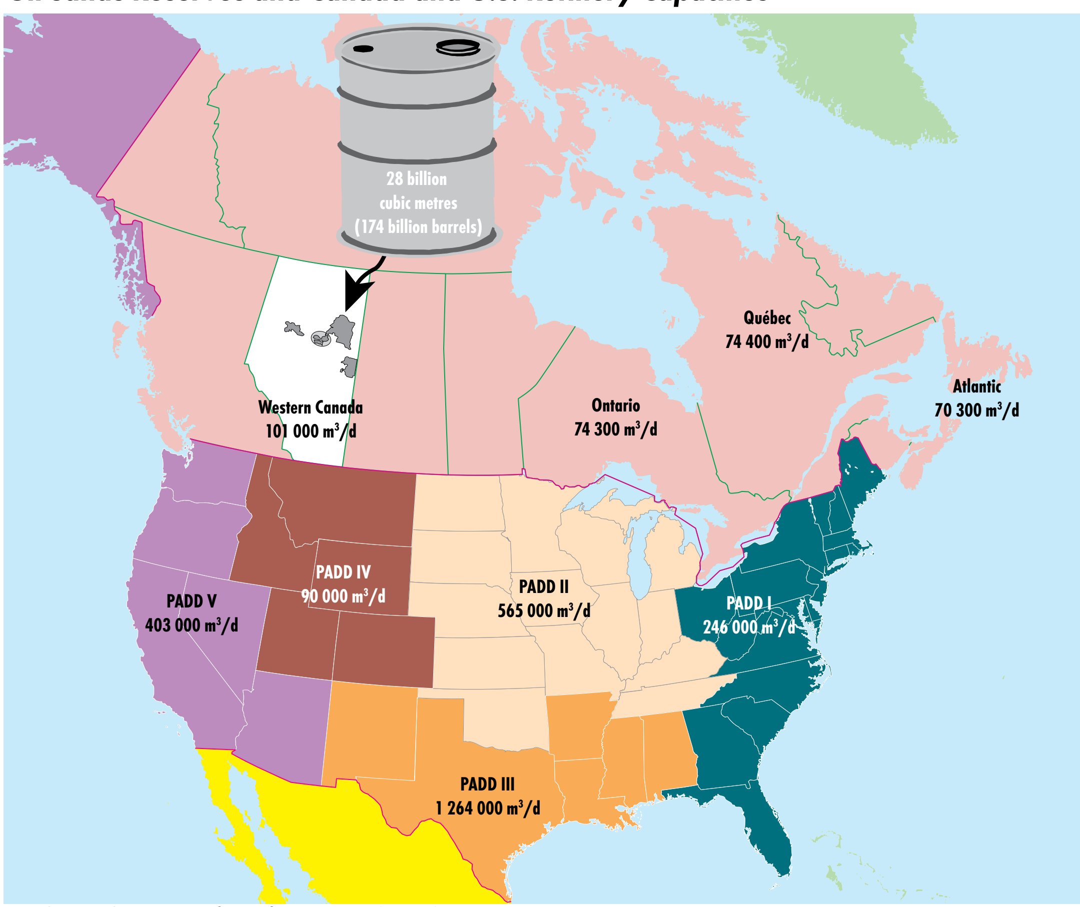
It is expected that there will continue to be rapid growth in the development of Canada's oil sands. There are, however, issues and uncertainties associated with the development of the resource. The rate of development will depend on the balance that is reached between the opposing forces that affect the oil sands. High oil prices, international recognition, geopolitical concerns, global growth in oil demand, size of the resource base and proximity to the large U.S. market, and potentially other markets, encourage development. On the other hand, natural gas costs, the high light/heavy oil price differential, management of air emissions and water usage, insufficient labour, infrastructure and services are concerns that could potentially inhibit the development of the resource.

Introduction

In May 2004, the Board released a comprehensive Energy Market Assessment (EMA) entitled *Canada's Oil Sands: Opportunities and Challenges to 2015*. It contained detailed discussions on major aspects of the oil sands industry and assessed the opportunities and issues facing development of the resource. Since then, there have been significant changes. In recognition of the need for current information, the Board decided to provide this update for stakeholders, which highlights the major changes and new developments. The main purpose of this report remains the same—to provide an objective assessment of the current state of the oil sands and the potential for growth. It is assumed that readers are familiar with the topic but those readers seeking additional background information are encouraged to refer to the previous report which is available on the Board's website at www.neb-one.gc.ca.

FIGURE 1.1

Oil Sands Reserves and Canada and U.S. Refinery Capacities



Petroleum Administration for Defense District (PADD)

Canada's oil sands are a substantial resource. According to the Alberta Energy and Utilities Board (EUB), Alberta's oil sands contain an ultimately recoverable crude bitumen resource of 50 billion cubic metres (315 billion barrels), with remaining established reserves of almost 28 billion cubic metres (174 billion barrels) at year-end 2004[i].

The rapid pace of development continues to be driven by several factors, including:

- higher oil prices;
- concerns surrounding the global supply of oil;
- market potential in the U.S. and Asia; and
- stable generic fiscal terms for producers.

Key assumptions that underlie the current analysis compared to the May 2004 report are as follows:

Assumptions	**June 2006 Report**	**May 2004 Report**
West Texas Intermediate (WTI) crude oil price	US$50 per barrel	US$24 per barrel
NYMEX natural gas price	US$7.50 per MMBtu	US$4 per MMBtu
Light/heavy crude oil price differential	US$15 per barrel	US$7 per barrel
Canadian dollar exchange rate	US$0.85	US$0.75

As in the previous report, sensitivities around the oil price, natural gas price, exchange rate and other cost components were used for the supply cost estimates.

This report can broadly be considered as having four key components:

- economic potential and development of the resource base;
- markets and pipelines;
- environmental and socio-economic impacts; and
- potential opportunities in the electricity and petrochemical industries.

The outline of the report is as follows:

- Chapter 1 is an introduction to the report;
- Chapter 2 analyzes supply costs;
- Chapter 3 discusses crude oil production and supply;
- Chapter 4 provides a synopsis of the potential markets for the rising oil sands supply;
- Chapter 5 describes the major crude oil pipeline network and expansion plans;
- Chapter 6 highlights the environmental concerns over water, air quality, by-product and waste production from oil sands activity and related socio-economic impacts;
- Chapter 7 assesses the opportunity for electricity generation; and
- Chapter 8 concludes with a discussion on the potential opportunities for the petrochemical industry.

Supply Costs

2.1 Introduction

Since the Board's May 2004 report, the economic environment, particularly with respect to energy, has changed significantly. For the oil sands sector, this has meant a substantial escalation in the costs to develop and operate projects, but also greater revenues with currently higher oil prices and a general view that higher prices will endure into the foreseeable future.

Capital costs have risen dramatically due to higher prices for steel, cement and equipment. The rising pace of development has also led to a shortage of skilled tradespersons and a reduction in the overall productivity of labour. These cost escalations and the challenge in attracting skilled labour are being felt all across the world, but are particularly severe in the oil sands region because of its relatively remote location, the high pace of development, and the scope and complexity of the projects being undertaken.

The rise in energy prices has been the most dominant factor influencing project economics and the oil sands development drive. Higher oil prices have boosted revenues; however, operating costs have also increased significantly with the rise in electricity and natural gas prices. The latter is of particular importance with an estimated 1 Mcf required to produce each barrel of bitumen. For in situ producers, the availability and price of diluent for blending has become a more pressing issue, as has the market value of heavy versus light crude oil (the differential) in traditional markets.

Table 2.1 provides a summary of current oil sands operating costs and supply costs for major recovery methods. Operating costs can generally be considered as reflecting the cash costs of operation while supply costs include all costs associated with production, including operating cost, capital cost, taxes, royalties and a rate of return on investment. Supply costs are stated as a range, reflecting variables such as: reservoir quality, depth of the producing formation, project size, recovery method and operating parameters.

TABLE 2.1

Estimated Operating and Supply Costs by Recovery Type

C$(2005) per barrel at the Plant Gate	**Crude Type**	**Operating Cost**	**Supply Cost**
Cold Production – Wabasca, Seal	Bitumen	6 to 9	14 to 18
Cold Heavy Oil Production with Sand (CHOPS) – Cold Lake	Bitumen	8 to 10	16 to 19
Cyclic Steam Stimulation (CSS)	Bitumen	10 to 14	20 to 24
Steam Assisted Gravity Drainage (SAGD)	Bitumen	10 to 14	18 to 22
Mining/Extraction	Bitumen	9 to 12	18 to 20
Integrated Mining/Upgrading	Synthetic	18 to 22	36 to 40

Compared with the last report, most of the costs in this table are significantly higher. The primary reasons for the changes are higher natural gas prices and increasing capital costs for project construction.

2.2 Project Economics

This section provides an update to the Board's project economic work that was completed as part of the 2004 report. The reader is encouraged to review the previous work for more information on methodology and for a greater understanding on how project economics have changed.

The Board decided to examine the economics of Steam Assisted Gravity Drainage (SAGD) and integrated mining as it is anticipated that these operations will form the bulk of supply growth through 2015. Although Cyclic Steam Stimulation (CSS) has been employed successfully in the Cold Lake oil sands region for over 20 years, it is not anticipated that its application will be expanded significantly over the timeframe of this report.

In this report, as in the previous one, the Board developed a discounted cash flow model to determine supply cost. This resulting supply cost is defined as the constant dollar crude oil price required over the life of the project to cover all costs, except land acquisition costs that can vary widely, and provide a 10 percent real rate of return (12 percent nominal) on investment.

Economic and market assumptions are available in Appendix 1 and major modelling assumptions are available in Appendices 2 and 3. The following are the key assumptions used in the analysis (2005 dollars):

- WTI at Cushing, Oklahoma is US$50 per barrel;
- NYMEX natural gas is US$7.50 per MMBtu;
- U.S./Canada exchange rate is 0.85; and,
- light/heavy crude oil differential (Par versus Lloydminster Blend) is US$15 per barrel (30 percent).

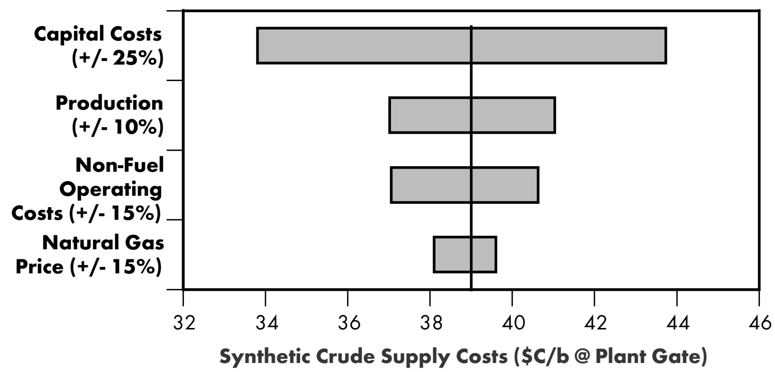
2.2.1 Integrated Mining/Extraction and Upgrading

An update to the economic evaluation for a 31 700 m^3/d (200 Mb/d) integrated mining/extraction and upgrading operation has been performed. This model is intended to emulate a greenfield project with construction beginning in 2006 and first production in 2010. The mining project evaluated is assumed to produce synthetic crude oil (SCO) of similar quality and value to conventional light oil.

Figure 2.1 shows a supply cost for SCO at the plant gate of about $39 per barrel. This compares to a supply cost of $26 in the 2004 report. The main reasons for the increase are higher capital costs (up 37 percent), higher natural gas prices (up 88 percent), and increased non-gas operating costs (up 20 percent). In addition, supply costs include royalties and taxes which increase under higher oil prices.

FIGURE 2.1

Supply Cost Sensitivities: 200 Mb/d Athabasca Mining/ Extraction and Upgrading Project



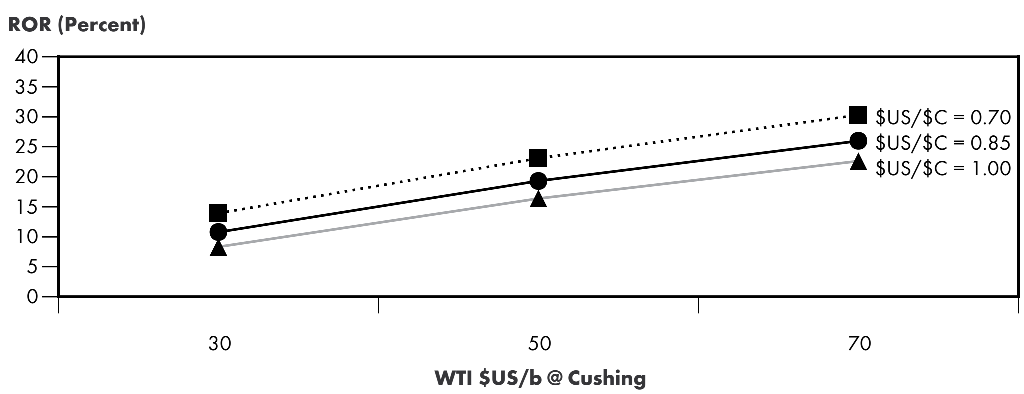
The supply cost continues to be most sensitive to changes in capital costs. A 25 percent increase or decrease in capital costs results in a nearly $5 per barrel change in supply cost. Also important to note is the sensitivity to overall production levels vis-à-vis design rates. Improving operational reliability and minimizing unplanned maintenance continues to be a major focus of integrated mining operations today.

Figure 2.2 illustrates the economic performance of the hypothetical integrated mining project for different combinations of the oil price and the exchange rate. At US$50 per barrel for WTI, the project is estimated to provide a rate of return of 16 to 23 percent.

It is estimated that US$30 to $35 per barrel for WTI is required to provide a 10 percent real rate of return to the producer. Continued escalation in material and labour costs pose a risk to this outlook. Each 10 percent increase in capital costs is estimated to increase the required WTI price by US$2 per barrel.

FIGURE 2.2

After-tax Nominal Rate of Return: 200 Mb/d Athabasca Mining/Extraction and Upgrading Project



2.2.2 SAGD

An update to the economic evaluation for a 19 000 m^3/d (120 Mb/d) Athabasca SAGD operation has been performed. The SAGD project is assumed to produce a condensate-bitumen blend (dilbit) of similar quality and value to Lloydminster Blend (LLB).

FIGURE 2.3

Supply Cost Sensitivities: 120 Mb/d Athabasca SAGD Project – High-Quality Reservoir

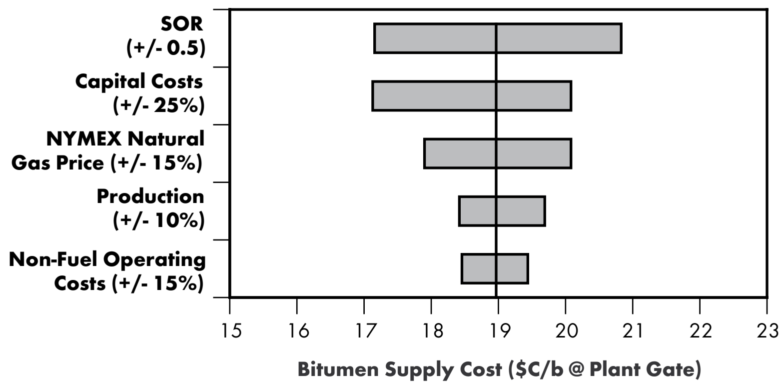


Figure 2.3 shows a supply cost for bitumen at the plant gate of about $19 per barrel. This compares with a supply cost of about $13 in the 2004 report. As with the integrated mining case, one of the main reasons for the increase is higher capital costs, which are up 45 percent. This increase is driven not only by the escalation of material and labour costs, but also by more conservative assumptions regarding reservoir performance resulting in more wells being drilled over the life of the project. Higher natural gas prices (up 88 percent) also contribute significantly to higher supply costs, since purchased natural gas requirements are estimated at approximately 1 Mcf per barrel. Non-gas operating costs have been reduced from $5.00 per barrel to $3.50 reflecting operator progress and estimates from the most recent project plans.

Over the past number of years, Western Canada Sedimentary Basin (WCSB) supply of the traditional blending agent, pentanes plus (C5+), has been flat to declining while, at the same time, demand from bitumen producers has been increasing. As a result of these market conditions, prices have been rising. Historically, C5+ in western Canada has had a market value of about five percent above Edmonton Par crude. In 2005 and in the first quarter of 2006, however, this premium has increased to an average of about 10 percent. At present, there exists no means of importing large quantities of blend stock into Alberta; therefore, it is not anticipated that this price premium will ease in the near term. For this reason, a 10 percent premium of C5+ over Edmonton Par crude has been incorporated into the SAGD project economics.

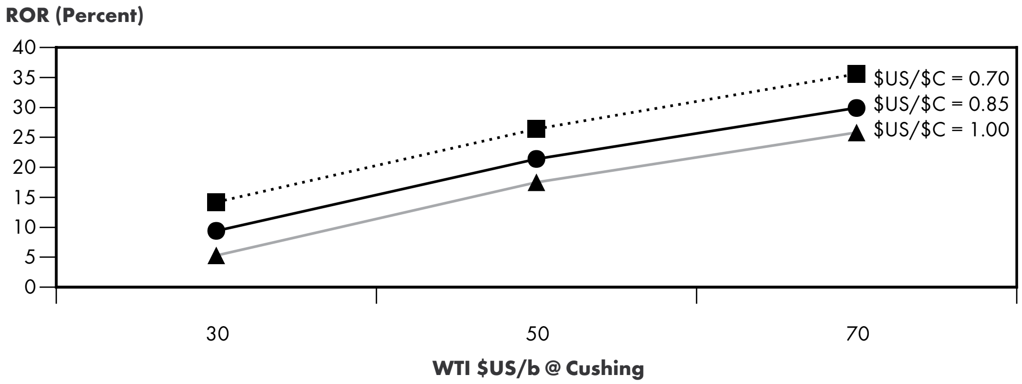
The supply cost is highly sensitive to the steam-to-oil ratio (SOR), a measure of how much energy must be applied to the reservoir to induce bitumen to flow into the well bore. For dry steam (100 percent), an increase of 0.5 in SOR translates into approximately 200 standard cubic feet (scf) in added natural gas consumption and increased water handling costs. Together, these amount to a nearly $2 per barrel increase in supply cost.

Figure 2.4 illustrates the economic performance of the hypothetical Athabasca SAGD project for different combinations of the oil price and the exchange rate. At US$50 per barrel for WTI, the project is estimated to provide a rate of return of 16 to 27 percent.

It is estimated that US$30 to $35 per barrel for WTI is required to provide a 10 percent real rate of return to the producer. As in the integrated mining case, continued escalation in material and labour costs pose a risk to this outlook. Each 10 percent increase in capital costs is estimated to increase the required WTI price by US$1.50 per barrel.

FIGURE 2.4

After-tax Nominal Rate of Return: 120 Mb/d Athabasca SAGD Project – High-Quality Reservoir (Canada–U.S. Exchange Rate Sensitivity)

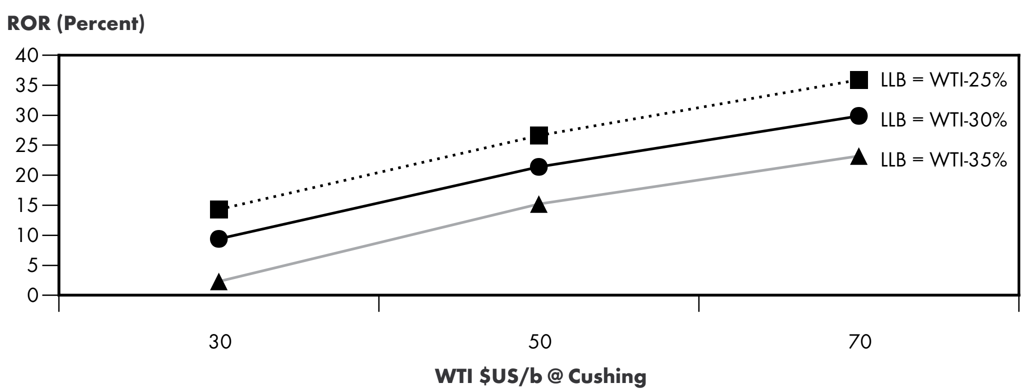


Recently, oil sands supply growth has outpaced demand in traditional markets for Canadian heavy oil. This situation has resulted in deep price discounting for heavy blends and substantially wider light/heavy oil differentials, both on a dollar and percentage basis. Figure 2.5 shows that a long-term widening (narrowing) of the differential has a significant negative (positive) impact on project economics.

Although there are likely to be periods where markets are unbalanced, resulting in a widening or narrowing of the differential, wide differentials provide refiners with an economic incentive to build heavy oil conversion capacity, while narrow differentials lessen the need to construct conversion capacity. For this reason, it is expected that the historical relationship of Lloydminster Blend at about a 30 percent discount to Edmonton Par crude will prevail over the longer term.

FIGURE 2.5

After-tax Nominal Rate of Return: 120 Mb/d Athabasca SAGD Project – High Quality Reservoir (Light/Heavy Differential Sensitivity)



2.3 Outlook: Issues and Uncertainties

Under today's market conditions, integrated mining and SAGD are estimated to be economic at US$30 to $35 per barrel for WTI. In recent years, higher oil prices have bolstered the economics of prospective projects. On the downside, however, higher energy costs, higher capital costs, a rising Canadian dollar relative to the U.S. dollar, and widening light/heavy differentials have proved to be significant challenges.

The supply cost projections and project economic analysis presented in this chapter are based on operational and market assumptions. Significant changes to these underlying assumptions may alter the results of the analysis materially. The following are the key risks and uncertainties to the outlook:

- **Crude oil prices:** Oil sands are relatively expensive to produce; a significant drop in oil prices may lead to poor economics for many existing and potential projects. The persistence of wider than average light/heavy differentials will negatively affect project economics for those producers marketing heavy blends.
- **Capital costs:** Oil sands projects, particularly those involving upgrading facilities, are very capital intensive and project economics are extremely sensitive to capital costs. Continued escalation in raw material and labour costs will have a material impact on supply costs and project economics.
- **Natural gas costs:** Both integrated mining and thermal in situ operations are intensive users of natural gas. Over the past several years, the price of natural gas has increased substantially. The future price of natural gas and the development of alternatives, including fuel substitutes and gasification, will have a material impact on supply costs and project economics.
- **Diluent availability:** With WCSB supply of the traditional blending agent, pentanes plus, flat to declining, and demand from bitumen producers increasing, prices for diluent are rising. There are pipeline proposals to import diluent into Alberta. The future cost of blend stock will affect project economics.
- **Technology:** In the past, technology has enabled step-wise reductions in supply costs. Technology currently under development such as mobile crushing equipment and "at-the-face" slurrying for mining projects, and solvent-aided production (SAP) and low-pressure SAGD for in-situ projects, have the potential to reduce operating costs significantly. In addition, improvements in upgrading costs are anticipated as new or modified upgrading technologies are employed.

Crude Oil Supply

3.1 Introduction

Since the Board's 2004 report, activity in the oil sands has ramped up sharply. This has been primarily due to:

- sustained higher oil prices since 2004, which have resulted in increased cash flows and profitability for oil sands operators;
- an outlook for sustained high oil prices in the future; and,
- increased recognition that the oil sands represent a very large, economically attractive accumulation of oil in a politically stable country.

Companies have been aggressively accelerating plans for expansion of existing projects and initiating new projects. Many new players have been attracted to the oil sands, with several of the world's multi-national oil companies now represented, as well as several subsidiaries of foreign national oil companies.

Relatively wide light/heavy oil price differentials over the past several years have made the prospect of adding local upgrading capacity more attractive. As a result, most plans for large-scale mining and in situ projects now include consideration of upgrading. As well, one "merchant" or third-party upgrader has been approved and two more are in early planning stages.

These aggressive expansion plans are countered by a number of significant constraints, including a shortage of skilled labour, lack of adequate infrastructure, rapidly escalating construction costs and uncertainty regarding the scope and cost of managing environmental impacts.

3.2 Crude Bitumen Reserves

According to the Alberta Energy and Utilities Board (EUB), Alberta's oil sands areas contain an ultimately recoverable crude bitumen resource of 50 billion cubic metres (315 billion barrels), with remaining established reserves of almost 28 billion cubic metres (174 billion barrels) at year-end 2004[ii].

In Saskatchewan, exploration efforts to define unconventional oil resources are ongoing in two areas. The first involves crude bitumen deposits located in northwest Saskatchewan, across the border from the Firebag area in Alberta. The second involves oil shale deposits in the Pasquia Hills region of east-central Saskatchewan. Official estimates of the size of these resources are not yet available.

3.3 Expansion Plans

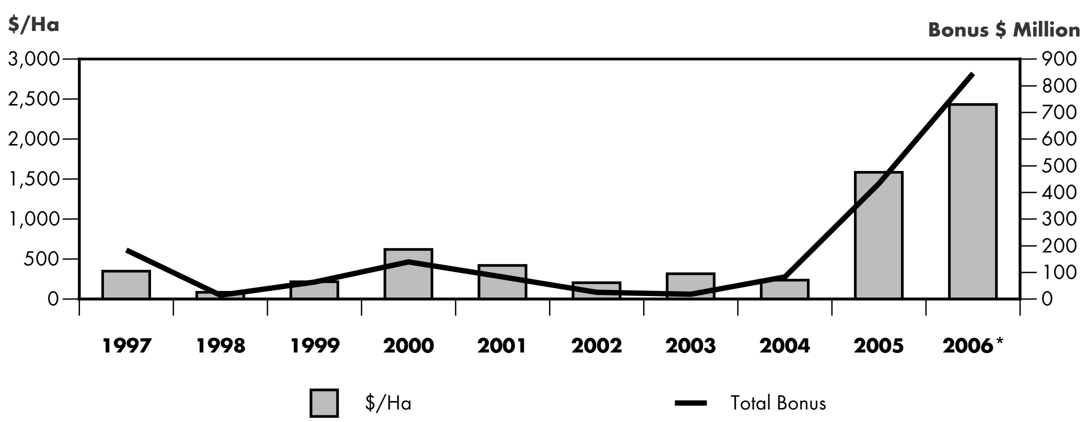
The fees paid to the Alberta government for the right to explore and develop oil sands leases provide a good indicator of the heightened interest in the oil sands over the last several years. Land sale "bonuses" reached record levels in 2005 and early 2006, with prices paid averaging $2,200 per hectare. In 2005, total bonuses reached $450 million, more than double any previous year (Figure 3.1).

Another indicator of the rising interest over the past two years is the plethora of announcements regarding new projects or expansion plans for existing projects. Major project plans include:

- Suncor Energy (Suncor) announced its Voyageur growth strategy, a multi-phased plan designed to increase the company's oil sands production capacity to a range of 79 500 m^3/d to 87 300 m^3/d (500 Mb/d to 550 Mb/d) by 2010 to 2012;
- EnCana Corporation (EnCana) will utilize SAGD technology to expand production from its leases to 79 500 m^3/d (500 Mb/d) by 2016;
- Canadian Natural Resources Limited (CNRL) announced additional phases to its Horizon Oil Sands mining project to expand production to 79 500 m^3/d (500 Mb/d) by 2018, plus plans to expand in situ production by 47 700 m^3/d (300 Mb/d);
- Imperial Oil Limited (Imperial) and Exxon Mobil Canada (ExxonMobil) filed a regulatory application for a three-phase 47 700 m^3/d (300 Mb/d) mining project at Kearl;
- Shell Canada Limited (Shell) announced expansion plans at both its Peace River and Jackpine Lake properties;
- Petro-Canada, partnered with UTS Energy Corporation (UTS) and Teck Cominco Ltd., received regulatory approval for the 16 000 m^3/d (100 Mb/d) Phase 1 of the Fort Hills mining project;
- Husky Energy (Husky) received regulatory approval for its Sunrise project, with capacity of 31 800 m^3/d (200 Mb/d) over four phases, and disclosed plans to expand its Lloydminster upgrader to 23 800 m^3/d (150 Mb/d) of synthetic crude oil (SCO) and diluent production capacity;

FIGURE 3.1

Oil Sands Land Sales



* January and February data only.

- BA Energy Inc. (BA) received approval for its three-phase 23 800 m^3/d (150 Mb/d) SCO production capacity Heartland Upgrader project, to be built in Strathcona County northeast of Edmonton, Alberta;
- North West Upgrading Inc. (North West) has disclosed plans for its North West Upgrader, a three-phase 31 800 m^3/d (200 Mb/d) merchant upgrader to be located in Sturgeon County, near Edmonton;
- Total E&P Canada has acquired Deer Creek Energy and its Joslyn oil sands operations and leases;
- Shell EP Americas, a subsidiary of Royal Dutch Shell Plc, recently purchased 10 properties in northern Alberta targeting bitumen deposits situated in carbonate formations and formed a new company, SURE Northern Energy Ltd., to develop its new holdings; and
- Chevron Corporation (Chevron) recently acquired five heavy oil leases in the Athabasca region and anticipates developing these leases using SAGD technology.

Examples of participation by foreign national oil companies include:

- SinoCanada Petroleum (SinoCanada), a subsidiary of China-based Sinopec Group, has partnered with Synenco Energy Inc. (Synenco) to develop the proposed Northern Lights project, an integrated mining, extraction and upgrading project, with the upgrader to be located in Sturgeon County near Edmonton;
- China National Offshore Oil Corporation (CNOOC) bought a 17 percent stake in MEG Energy Corporation (MEG), the developer of the Christina Lake project, which is designed to produce 4 000 m^3/d (25 Mb/d); and
- Enbridge Inc. (Enbridge) has entered into a memorandum of understanding with PetroChina International Company Limited (PetroChina) to cooperate on the development of the Gateway Pipeline and supply crude oil from Canada to China.

The number of major mining, upgrading and thermal in situ projects has grown to include some 46 existing and proposed projects, encompassing 135 individual project expansion phases in various stages of execution, from those announced to those already under construction. A list of these projects is presented in Appendix 4. More detail on Alberta's oil sands projects can be found at the Alberta Economic Development website at: http://www.alberta-canada.com/oandg/oilsands.cfm. A comprehensive list of projects can also be found at: http://www.strategywest.com.

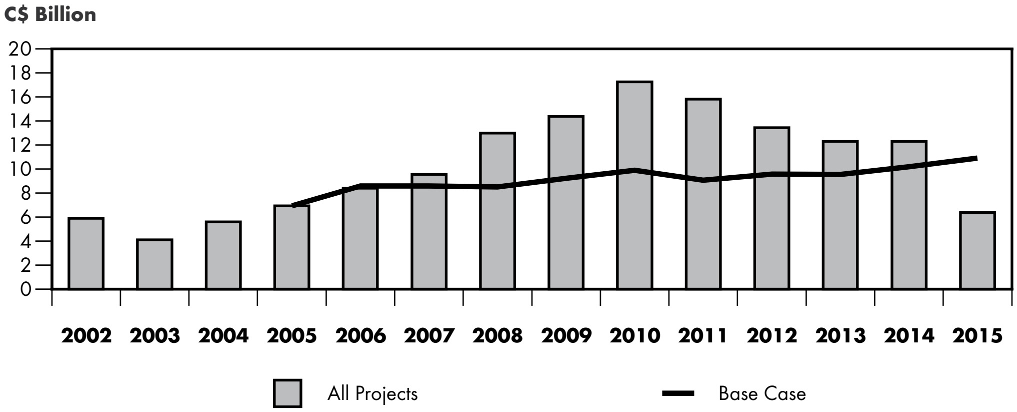
Primary, or non-thermal in situ production, is still an important component of the total oil sands picture, accounting for nearly 10 percent of total bitumen production in 2005. There are isolated regions within the oil sands areas, such as at Seal, near Peace River, and Brintnell and Pelican Lake in the Wabasca region, where primary production levels are growing significantly and where operators are reporting success with secondary recovery via waterflooding.

3.4 Capital Expenditures

Indicated total capital expenditures for oil sands projects have increased substantially since the 2004 report. Estimates of capital expenditures to construct all announced projects over the period 2006 to 2015 total C$(2005) 125 billion (Figure 3.2). This level of capital expenditure is roughly twice that indicated in the Board's previous report.

F I G U R E 3 . 2

Estimated Capital Expenditures



There is a logjam of announced projects in the 2008 to 2012 period. It is expected that not all projects will proceed as originally scheduled; some will be delayed and some may be cancelled. Figure 3.2 also illustrates an adjusted capital spending profile, which is based on the Board's "Base Case" projection of oil sands production discussed in the following section. A discounting of about 35 percent below the "All Projects" case is indicated, with expenditures over the period 2006 to 2015 estimated to be about C$95billion.

3.5 Oil Sands Production

Crude bitumen is produced by mining and extraction, in situ thermal recovery and in situ non-thermal recovery. Currently, about 60 percent of crude bitumen is transformed by upgrading into various grades of SCO or upgraded products. Figure 3.3 illustrates the projected oil sands supply in terms of upgraded and non-upgraded bitumen. The supply projections indicate a relatively aggressive ramp-up in capacity that extends to 2015. In the present high oil price environment, lease owners are keen to realize the value associated with typically large resource holdings. In general, the companies involved are large Canadian companies or multi-national companies with significant capital and considerable experience in developing heavy oil resources, both in Canada and abroad. However, many smaller companies are also able to take advantage of favourable capital markets to initiate project plans.

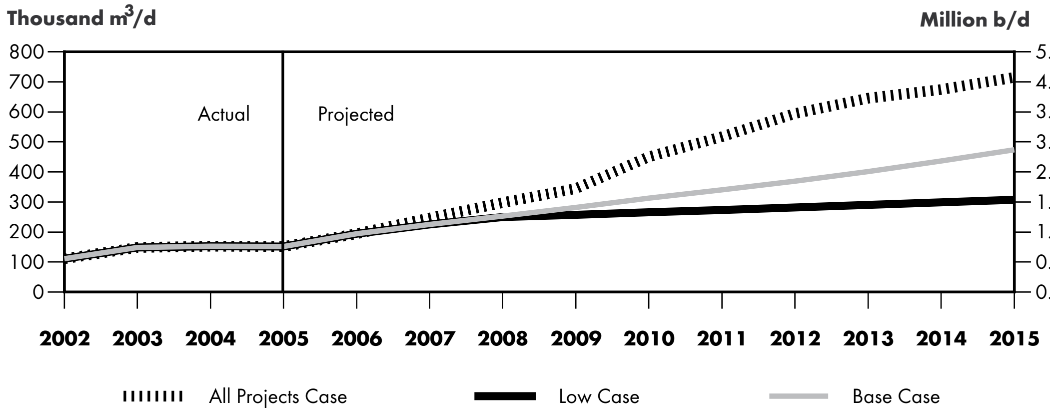
The All Projects case assumes that all projects publicly announced to date commence operation at their name-plate volume and start date. This would result in production of about 699 500 m^3/d (4.4 MMb/d) by 2015, which is considered to be beyond the limits of capacity growth that could be reasonably expected within that time period.

The lower bound or "Low Case" projection is shown to directionally illustrate what might happen if the economic viability of oil sands projects is compromised, perhaps by sharply lower prices. An outlook for sustained oil prices below US$35 per barrel would lead to marginal economics for many projects in the present business environment and would slow development. It is anticipated that production growth would decline to about four percent, or about half the growth rate of the "Base Case".

The development of the Base Case projections is based on a sustained high oil price and an economically attractive environment. Several companies have adopted a continuous construction philosophy; that is, to keep a workforce on hand dedicated to the construction of a series of company

FIGURE 3.3

Projected Oil Sands Production



projects or project expansions in succession. There is also a wealth of experience throughout the industry that bodes well for future development. While there may be constraints, such as labour shortages and lack of infrastructure, it is anticipated that the industry's ability to add capacity will gradually increase year-over-year.

A review of projects currently under construction and those in various stages of planning and execution reveals that there is a surplus of projects sponsored by experienced and credible proponents; the challenge becomes one of defining the limits of growth that can reasonably be expected. With the rapid escalation of construction and material costs over the last two years, and with industry's greater ability to finance large projects, defining a limit to growth based on capital expenditure seems a less appropriate approach.

Because of the long lead times associated with oil sands projects, the production outlook for the period 2006 to 2010 is already largely defined by projects currently under construction or substantially advanced in their project planning. On the assumption these projects will be built, a review of the resultant growth profile over the period 2000 to 2010 should provide a good indication of industry's ability to ramp up capacity.

Over the period 2006 to 2010, annual production additions will be in the order of 30 200 m^3/d (190 Mb/d). Beyond 2010, this rate of additions increases (plus one percent per year is assumed for the projection) and expands to 31 700 m^3/d (200 Mb/d) by 2015. Projects are assigned from the list of available projects and timelines adjusted to match this growth profile. The associated capital expenditure is in the order of C$8 billion per year over the course of the projection. This is based on estimates of the capital spending requirement, per unit of daily capacity, for each type of project as set out in Table 3.1.

TABLE 3.1

Capital Spending Requirement

Project Type	Capex per daily flowing barrel
CSS	$20,000
SAGD	$15,000
Mining & Extraction	$20,000
Upgrading	$32,000

In the Base Case projection, supply of upgraded and non-upgraded bitumen rises from about 175 000 m^3/d (1.1 MMb/d) in 2005 to 472 000 m^3/d (3.0 MMb/d) in 2015. Compared with the 2004 report, projections for upgraded bitumen are up 43 percent and are up 13 percent for non-upgraded bitumen. Non-thermal in situ production is up by five percent, as opposed to no growth in the last report.

3.5.1 Production by Type

Currently, about 60 percent of crude bitumen is upgraded into various grades of SCO or other upgraded products within the Fort McMurray and Edmonton regions. Note that there is generally some shrinkage of bitumen volumes through the upgrading process, depending on the type of process used. Overall, this loss is estimated to be about 11 percent.

There have been a number of recent announcements regarding new mining projects with associated upgraders and expansion of upgrading capacity at existing projects. As well, three third-party or merchant upgraders have been announced with one, the BA Heartland Upgrader, already under construction. The OPTI/Nexen Long Lake SAGD project is the first to feature the on-site upgrading of in situ production. These various projects have added a significant amount of potential upgrading capacity. Further discussion of upgrading projects can be found in *Chapter 4 - Markets*.

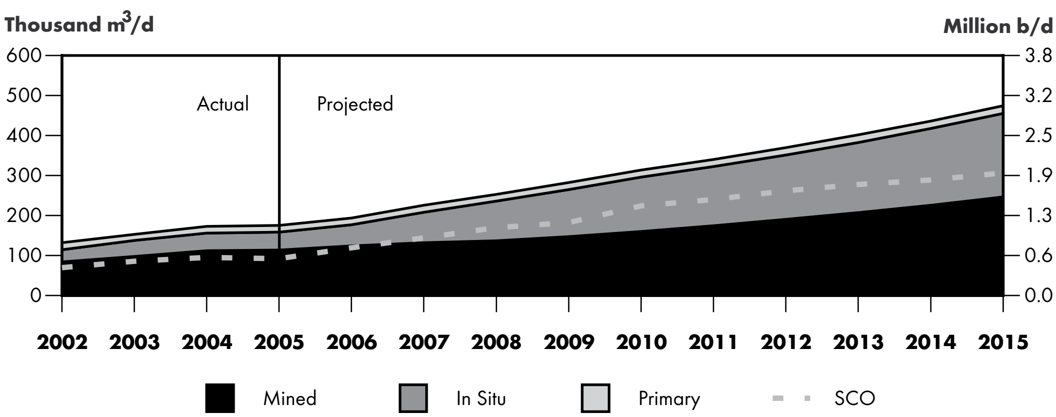
In the Base Case projection, the net bitumen volumes produced from mining operations, thermal in situ, and primary (non-thermal) in situ operations account for 52 percent, 44 percent and four percent, respectively, by 2015 (Figure 3.4). The bitumen feedstock for upgrading is sourced from both mining and in situ types of recovery operations. By 2015, upgraded crude oil (synthetic or SCO) production is projected to be 306 000 m^3/d (1.9 MMb/d), or about 65 percent of total oil sands production.

3.6 Western Canada Sedimentary Basin Crude Oil Supply

Figure 3.5 provides a projection of production of crude oil and equivalent in the WCSB to 2015. The oil sands components of this chart are based on the Base Case projections discussed earlier, while the conventional light oil, conventional heavy oil and condensate projections are based on the 2003 NEB Supply and Demand Report Techno-Vert scenario, and exhibit long-term decline trends. As a result of rapidly growing oil sands production, total WCSB production will rise from 365 000 m^3/d (2.4 MMb/d) in 2005 to 613 000 m^3/d (3.9 MMb/d) by 2015, an increase of 68 percent.

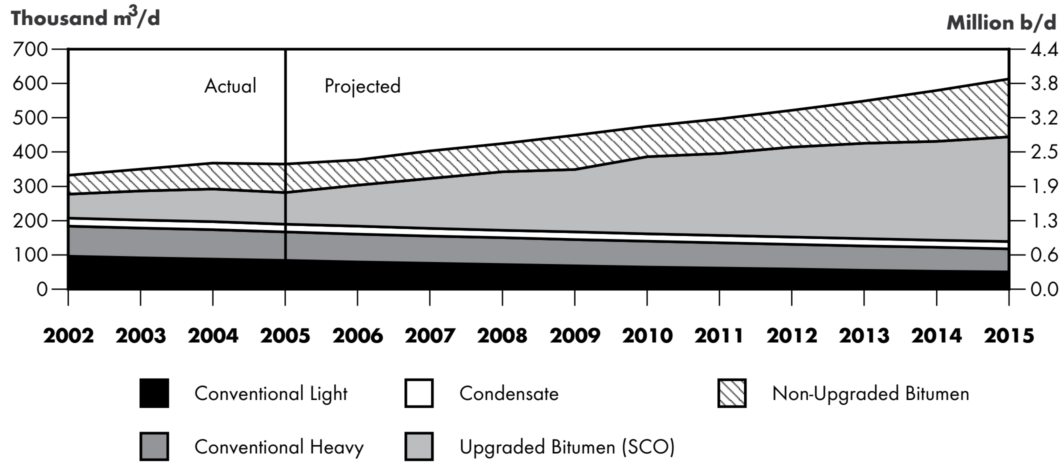
FIGURE 3.4

Oil Sands Production by Type – Base Case



F I G U R E 3 . 5

Projected Crude Oil Production – WCSB



3.6.1 Net Available Supply

Non-upgraded bitumen and heavy conventional crude oil need some degree of blending with a light hydrocarbon diluent to create a bitumen blend or heavy blend that is suitable for pipeline transportation. Gas condensate has been the traditional source of diluent for blending purposes, but increasing volumes of non-upgraded bitumen have outpaced available condensate supplies, putting upward pressure on prices and forcing producers to develop alternate strategies.

The projections of available supply take into account the diluent requirements for blending heavy oil and non-upgraded bitumen, recycled volumes of diluent, product losses during upgrading and volumes of condensate not available for blending. There are a number of potential solutions to deal with anticipated shortfalls of condensate for blending purposes, such as offshore imports, long-haul recycle by truck or rail, diluent-return pipelines from the U.S., specifically refined diluents, and blending with light crude oil or SCO. If the proposed Mackenzie Valley Gas Pipeline is built, another 2 850 m^3/d (18 Mb/d) of condensate could be available.

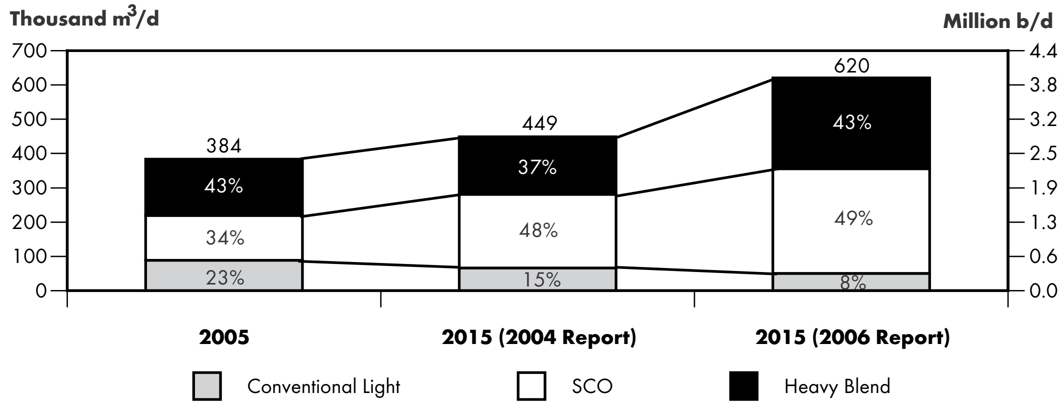
Figure 3.6 provides a view of the projected available supply by 2015, consistent with the Base Case projection. The relative volumes of conventional light crude oil, heavy blend and SCO are shown. The projections of available supply contained in this report total 620 000 m^3/d (3.9 MMb/d) in 2015, or about 38 percent higher than the 2004 report. The proportionate share of SCO increases slightly to 49 percent from 48 percent, while the share of blended heavy increases from 37 percent to 42 percent of total supply.

The volume of heavy blend indicated in the far right column, 260 000 m^3/d (1.6 MMb/d), would require approximately 40 000 m^3/d (250 Mb/d) of diluent beyond what is anticipated to be available from traditional domestic sources. The calculated demand for condensate is reduced if it is assumed that SCO or light crude are used as a diluent or additional upgrading capacity is built.

Further discussion of the issues facing oil sands producers regarding the types of crude oil produced, the degree and type of blending and other market choices can be found in *Chapter 4 - Markets*.

FIGURE 3.6

Net Available Supply – WCSB



3.7 Natural Gas Requirement

Oil sands projects are very energy intensive operations and require significant amounts of natural gas. The total oil sands related natural gas demand is determined by reviewing the projected production levels and gas usage factors for each of the major oil sands projects.

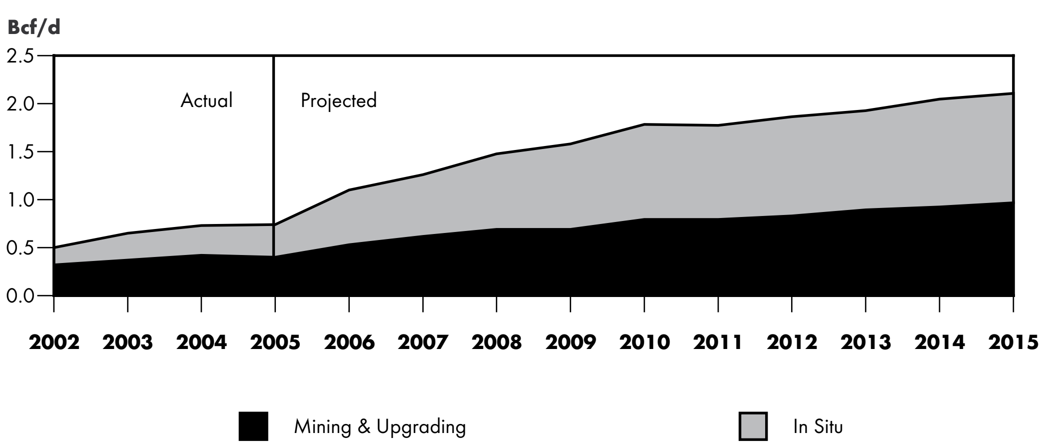
Figure 3.7 illustrates the total purchased gas requirement for the Base Case for in situ and for mining and upgrading projects. These values include purchased gas required to generate electricity on site. It does not include any requirements for stand-alone or merchant upgraders. By 2015, the total gas requirement is projected to be 2.1 Bcf/d.

Figure 3.8 illustrates the amount of purchased gas used per unit of bitumen recovery, or gas intensity, required for both oil sands mining and in situ projects, and includes gas used in on site cogeneration facilities to produce electricity for plant operations.

For in situ projects, the steam-to-oil ratio (SOR) is a measure of how efficiently energy is used in recovery of bitumen from the oil sands. An SOR of 2.5 equates to a gas intensity of 1.1 Mcf/b.

FIGURE 3.7

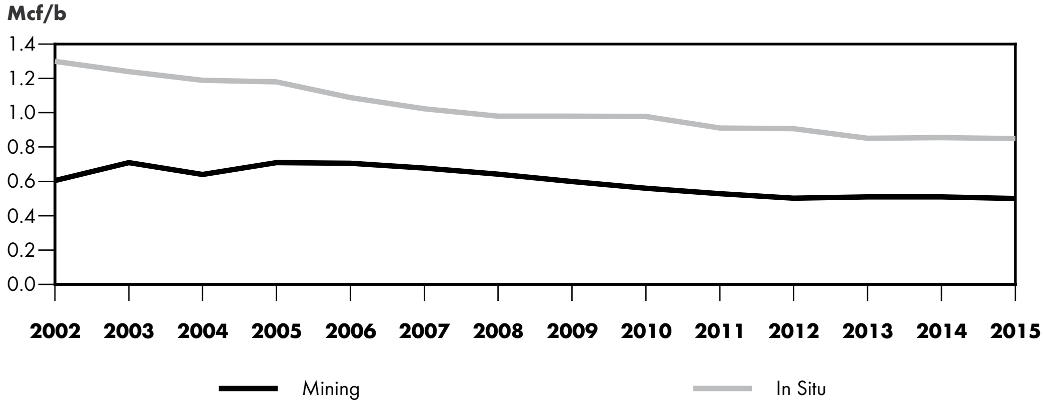
Total Purchased Gas Requirement



Source: EUB and NEB

FIGURE 3.8

Average Gas Intensity – Oil Sands Projects



A review of the performance of major steam-stimulation projects in operation reveals that very few have achieved that target, but this is expected to improve as operators make efficiency improvements. This applies especially to SAGD, still a relatively new technology. The Long Lake SAGD project, currently being constructed by Nexen and OPTI Canada, will be introducing a technology new to the oil sands—using bitumen gasification to create a synthetic gas (syngas) for process and fuel use, and thus reducing the need for external gas supply.

Another alternative to natural gas use for fuel is currently being pilot tested. Multiphase Superfine Atomized Residue (MSAR) features the clean and complete combustion of bitumen or refinery residue.

If these alternatives prove successful, it will lead to implementation in other projects, but probably not before the 2010–2012 timeframe. Efficiency improvements in SAGD and CSS operations are also anticipated through technological innovation, such as low-pressure SAGD or solvent aided production. However, going forward, as existing projects expand and new projects are initiated, it is likely that operators will be facing declining quality of bitumen reservoirs, with a resultant increase in energy required. The combination of these factors, including gas substitution, yields an overall improvement in average gas intensity to 0.9 Mcf/b by 2015.

For integrated mining projects, the natural gas intensity increases as the upgraders move to producing higher quality SCO, which requires more hydrogen. Some general improvements in energy efficiency are anticipated, and after about 2010–2012, it is predicted that newer technologies such as bitumen or coke gasification will be implemented, leading to significant improvement in average gas intensity. Some projects will use only natural gas, some will use gasification and others will use a combination of these. By 2015, the overall gas intensity for both in situ and mining/upgrading combined equates to an average of 0.7 Mcf/d.

3.8 Outlook: Issues and Uncertainties

The crude oil supply projections defined as the Base Case in this chapter are based on a "business as usual" outlook with oil and gas prices generally at or above the US$50 per barrel (WTI) and US$7.50 per MMBtu range, respectively. While the outlook is for a fairly quick ramp-up in oil sands production, there are issues that could impede the pace of capacity development. These include:

- **Crude oil prices:** It is believed that sustained lower oil prices below about US$35 per barrel would slow oil sands production growth and result in a material difference in projected volumes.
- **Natural gas usage:** High natural gas prices have encouraged oil sands operators to use gas more efficiently and to look for alternative fuels. The extent to which bitumen gasification or other alternatives to natural gas use prove successful and are adopted in additional operations will materially affect the purchased gas requirement in the oil sands.
- **Infrastructure:** The many projects proposed for the Fort McMurray area will put pressure on available infrastructure, such as housing, hospitals, schools and highways to transport the required materials, heavy equipment and modularized components. These issues could lead to delays in construction schedules.

MARKETS

4.1 Introduction

High oil prices coupled with robust global oil demand growth in the past several years have been key drivers in the expansion of the oil sands. In this regard, producers will be faced with a number of hurdles including choosing pipeline proposals to deliver these growing supplies to new and existing markets. In addition to market options, producers are assessing what they will be producing in the future. Will it be synthetic-bitumen blend (synbit), condensate-bitumen blend (dilbit), bitumen or synthetic crude oil (SCO)? As well, which markets can process those crude types and provide the best netback? These factors will determine which markets hold the greatest potential for oil sands producers.

The light/heavy differential is expected to remain wide for the next several years until sufficient upgrading capacity has been added. In addition to the large growth forecasted in oil sands bitumen production, international heavy crude oil output is also rising and, therefore, Canadian heavy crude oil may continue to be heavily discounted to ensure marketability. This is currently being exacerbated by increased crude oil production in the Rocky Mountain area and North Dakota.

The core market (i.e., Canada, upper PADD II, PADD IV and Washington State shown in Figure 5.1) can take increased volumes of crude oil, and pipeline expansions have taken place to facilitate this increase. In addition, expansion and extension into markets such as Wood River, Illinois; Cushing, Oklahoma; Washington State; the U.S. Gulf Coast; California and perhaps Asia are being considered through the various pipeline proposals.

Refiners in PADD II and PADD IV will continue to look to Canadian producers for their crude oil requirements, while producers will look for more options to market their supplies. This chapter reviews the Canadian and export markets for crude oil and examines the potential for market expansion to 2015.

4.2 Domestic Markets

Canada is a small refining market with nineteen refineries and a capacity of 320 000 m^3/d (2.0 MMb/d) (Table 4.1). In 2005, the refineries in Canada operated above 90 percent of capacity, primarily to meet the needs of the domestic market. Due to the age and lack of complexity of Canadian refineries, the domestic market does not hold tremendous growth opportunities for oil sands producers.

The refineries located in eastern Canada, including Ontario, import crude oil for their refining needs and process some eastern and western Canadian volumes. In 2005, less than 50 percent of Ontario's crude oil requirements were sourced from western Canada and of the total only 22 percent was SCO

TABLE 4.1

Receipts of Western Canadian Crude Oil – 2005 (m^3/d)

Market	Refining Capacity	Refining Runs	Conventional Light[1]	Conventional Heavy	Synthetic	Blended Bitumen	Total
W. Canada	100 529	91 526	37 232	18 082	31 868	3 787	90 969
E.Canada – Ontario	74 300	64 184	13 419	1 891	7 030	7 024	29 364
E. Canada – all	219 050	204 032	13 419	1 891	7 030	7 024	29 364
Total Canada	319 579	295 558	50 651	19 972	38 898	10 812	120 333

1 Includes condensates and pentanes plus.

FIGURE 4.1

Ontario Receipts of Western Canadian Crude Oil – 2005

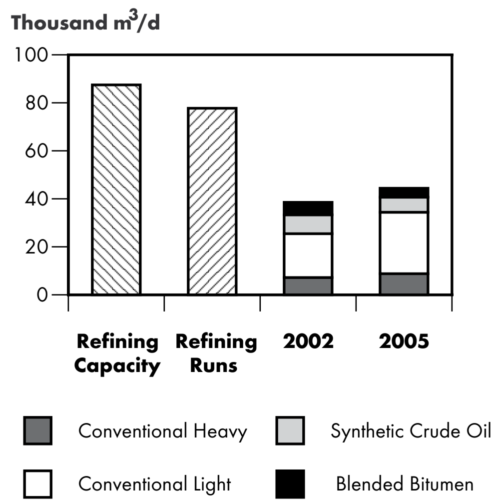
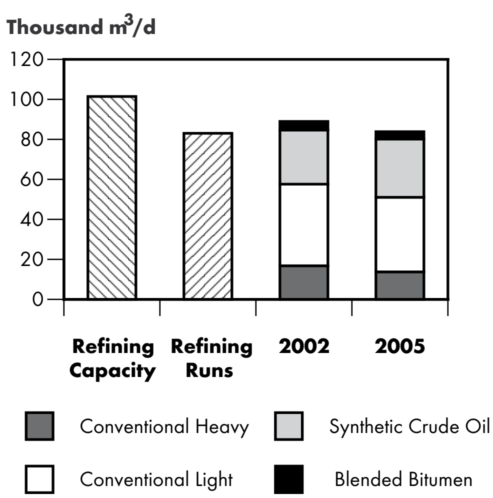


FIGURE 4.2

Western Canada Receipts of Western Canadian Crude Oil – 2005



and blended bitumen (Figure 4.1). Although there are few growth opportunities for western Canadian crude oil in Ontario and Québec, it has been suggested by some industry stakeholders that Enbridge could re-reverse Line 9. This would allow SCO to penetrate refineries located in Québec. It is expected that Imperial Oil Limited (Imperial), Suncor (Sunoco) and Shell Canada Limited (Shell) will look for opportunities to integrate their oil sands production with their downstream facilities located in Ontario.

The refineries located in western Canada process exclusively western Canadian production, including oil sands derived crude oil (Figure 4.2). In 2005, almost 40 percent of crude oil refined was SCO and blended bitumen. It is expected that the integrated companies such as Husky, Imperial, Petro-Canada and Shell who own refineries and have oil sands production will look for opportunities to integrate their upstream production with their downstream operations.

In 2003, Petro-Canada announced that it would convert its Edmonton refinery to refine exclusively oil sands feedstock. By 2008, the refinery will process 100 percent or 21 400 m^3/d (135 Mb/d) of oil sands feedstock. This will displace about 13 500 m^3/d (85 Mb/d) of conventional crude oil that Petro-Canada currently processes in its refinery. It will obtain these supplies through an agreement with Suncor who will process bitumen from Petro-Canada's MacKay River in situ facility into sour synthetic crude oil.

Recently, Husky announced that it is considering doubling the capacity of its upgrader at Lloydminster from its current 12 700 m^3/d (80 Mb/d) to 23 800 m^3/d (150 Mb/d) by 2009.

It would enable Husky to capture full value from increased production at its Cold Lake and Athabasca oil sands projects.

There are a number of proposals to upgrade bitumen, particularly with respect to mining projects with associated upgraders. As well, there have been three merchant upgrader proposals announced. The BA Heartland Upgrader project with a capital cost estimate of $900 million began site clearing and preparation for the first phase in September 2005. It will be located in Strathcona County, near Edmonton. Development will take place in three phases, with the start-up of the first phase scheduled for early 2008. The first phase will process 12 200 m^3/d (77 Mb/d) of bitumen blend. Once the project is fully expanded it will have a total processing capacity of 39 700 m^3/d (250 Mb/d).

North West Upgrading Inc. (North West) is planning to construct a heavy oil upgrader in Sturgeon County, near Edmonton. The first phase pending project approval in 2007 is expected to come on stream in early 2010 and will upgrade 8 000 m^3/d (50 Mb/d) of bitumen to SCO. Up to three additional phases are planned. The total processing capacity of the project when fully operational in 2015 would be 36 700 m^3/d (231 Mb/d) and would produce 28 600 m^3/d (180 Mb/d) of SCO and 6 700 m^3/d (42 Mb/d) of diluent.

Peace River Oil Upgrading Inc. has proposed a small scale upgrading facility to be located near McLennan, Alberta. Its proposal calls for an initial phase of 3 740 m^3/d (20 Mb/d) of bitumen processing capacity.

In addition to upgraders, there is a publicly announced proposal for a new refinery complex in Alberta. A C$7 to $8.5 billion integrated upgrader, petrochemical and electrical generation complex near Edmonton is being studied by Alberta Energy and 19 stakeholders. The refinery would initially be 47 700 m^3/d (300 Mb/d) and expandable to 71 500 m^3/d (450 Mb/d) and would include a petrochemical facility and a 500 megawatt coal-fired power generation plant. It could be completed as early as 2011. Some emerging concerns are that such a mega project could jeopardize other announced upgrading projects and expansions already underway.

4.3 Export Markets

In the Board's consultations with industry it was clear that refiners and producers have differing views on market expansion and extension. Not surprisingly, and consistent with the opinions expressed in the Board’s previous report, many believe that in the short-term the industry should maximize its volumes in its traditional markets of PADD II, PADD IV and Washington State, with further market expansions and extensions later in the decade into California, PADD III and the Far East.

4.3.1 United States

The United States with a refining capacity of almost 2.6 million m^3/d (16 MMb/d) is Canada’s largest market for crude oil exports and continues to possess the greatest potential for increased penetration of oil sands derived crude oil (Table 4.2). In 2005, exports declined 10 percent largely as a result of declining light conventional production and the outages at the three integrated oil sands facilities. Last year, Canada supplied almost 10 percent of U.S. crude oil refining needs, making it one of the largest crude oil exporters to that country. Continuing concerns about geopolitical events and security of supply are expected to be key drivers, as the U.S. looks to Canada as a secure source of supply.

TABLE 4.2

Export Receipts of Western Canadian Crude Oil – 2005 (m^3/d)

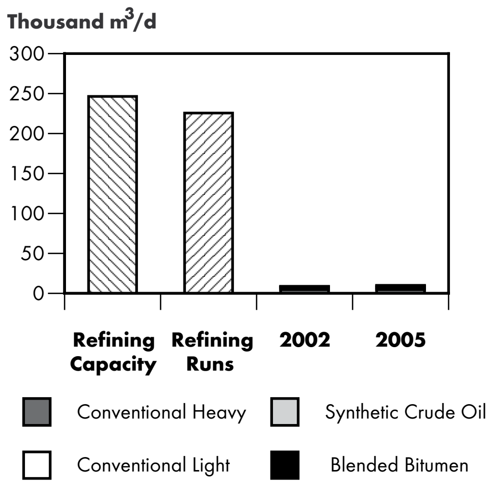
	Refining Capacity	Refining Runs	Conventional Light[1]	Conventional Heavy	Light Synthetic	Heavy Synthetic	Blended Bitumen	Total
PADD I	246 524	225 810	2 312	4 838	2 121	0	829	10 099
PADD II	564 740	525 714	11 345	88 737	16 849	15 730	30 416	163 078
PADD III	1 263 979	1 128 254	149	67	0	197	1 127	1 539
PADD IV	89 794	89 524	8 195	23 106	8 471	446	2 775	42 993
PADD V	403 317	459 841	8 744	750	2 308	1 631	972	14 406
Total U.S.	2 561 248	2 457 143	30 744	117 498	29 749	18 004	36 120	232 115
Other			0	0	0	315	70	385
Asia			0	0	0	0	0	0

1 Includes condensates and pentanes plus.

Source: NEB

FIGURE 4.3

PADD I Receipts of Western Canadian Crude Oil – 2005



4.3.1.1 PADD I

PADD I has a refining capacity of 246 500 m^3/d (1.6 MMb/d) and is not viewed as a large growth market for oil sands crude oil (Figure 4.3). Although not illustrated in Table 4.2, many of the refineries located in the U.S. northeast import crude oil from offshore eastern Canada.

The United refinery located in Warren, Pennsylvania is the exception and processes western Canadian crude oil. In 2005, it processed 21 percent SCO and eight percent blended bitumen. It is expected that United Refining will process an increasingly heavy crude slate as it moves ahead with the construction of a 2 200 m^3/d (14 Mb/d) coker. It is slated to be in service by 2009. As well, with the addition of the coker, refinery capacity is expected to increase by 790 m^3/d (5 Mb/d) to 11 000 m^3/d (70 Mb/d). Post-2009, United Refining will process 100 percent heavy crude oil.

United Refining receives western Canadian crude oil from Enbridge's Line 10 at Westover, Ontario, which has a capacity of 11 100 m^3/d (70 Mb/d). With future volumes expected to increase, there may be a requirement to expand that line.

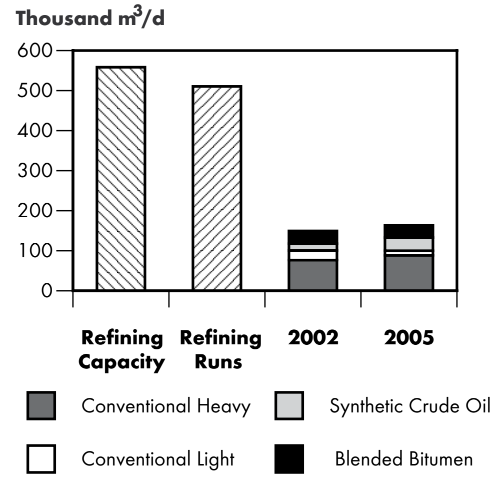
4.3.1.2 PADD II

PADD II is the largest market for western Canadian crude oil with a refining capacity of 567 000 m^3/d (3.6 MMb/d) (Figure 4.4). In 2005, 70 percent of western Canada's crude oil exports were delivered to PADD II. Twenty percent of those volumes were SCO and 19 percent were blended bitumen. PADD II continues to hold tremendous potential for western Canadian producers as deliveries represent only 31 percent of that region's total crude runs. As well, the core markets of northern

PADD II, including St. Paul and Chicago, are heavy and medium sour markets, which are a good fit for oil sands producers.

FIGURE 4.4

PADD II Receipts of Western Canadian Crude Oil – 2005



With the reversal of the Spearhead pipeline in March 2006, producers have the ability to deliver crude into southern PADD II. Deliveries into Cushing, Oklahoma open up several options to other locations that typically did not have access to Canadian crude oil in the past. By using existing underutilized pipelines and/or building new pipelines in southern PADD II, extension to other markets is possible. It is expected that this could result in better prices for western Canadian crude oil by extending the core market. Industry sees southern PADD II including Wood River, Cushing and Ponca City as good markets for synthetic and blended bitumen.

Western Canadian crude oil deliveries into Cushing have resulted in talks with the New York Mercantile Exchange (NYMEX) to create a futures contract for Western Canadian Select (WCS) at the Cushing hub. Introduced in 2004, WCS is a blend of 19 crude oil streams amounting to about 39 700 m^3/d (250 Mb/d) with an average of 19–21 API. The goal is to deliver 39 700 m^3/d to 79 500 m^3/d (250 Mb/d to 500 Mb/d) into Cushing, where Canadian crude oil could compete with foreign sour grades or U.S. Gulf Coast sour that would be delivered against it. A NYMEX contract is likely a year away as crude volumes need to increase.

Northern PADD II is well positioned to run increased volumes of bitumen blends and SCO because of the complexity of the refineries. Recently, heavy oil producers have been faced with an especially wide light/heavy differential. This reflects, in part, rising output from the oil sands and increased conventional production from North Dakota, Wyoming and Montana. This is further exacerbated by increased competition for limited pipeline space to deliver crude into the U.S. Midwest and limited facilities to process the heavier oil sands crude oil. This could be alleviated in the future as a number of companies identified an interest in constructing a coker or developing refinery expansion plans that would allow them to process heavier crude oil to take advantage of the wide light/heavy differential and the expected increase in oil sands production. Some U.S. companies, for example Marathon Oil, that have a number of refineries in PADD II, have publicly stated that they would like a stake in the oil sands to have an "integrated" arrangement between their refineries and production. The announced refinery projects are listed in Table 4.3.

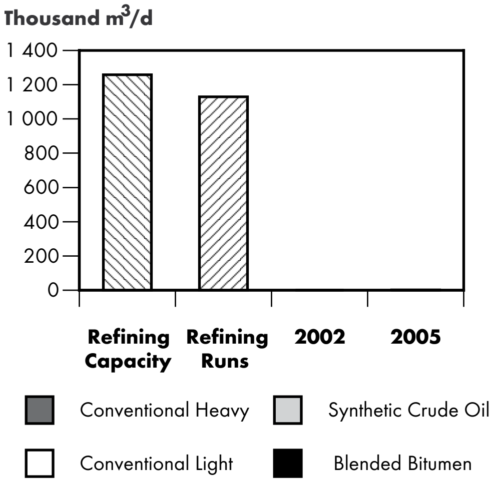
In May 2006, Enbridge announced its Southern Lights project, which includes a return diluent line from the Chicago area, as well as additional light crude oil capacity out of western Canada and a new light sour crude oil pipeline between Cromer, Manitoba and Clearbrook, Minnesota. For more information see *Chapter 5 - Major Crude Oil Pipelines*.

4.3.1.3 PADD III

PADD III has a refining capacity of 1 265 000 m^3/d (8.0 MMb/d) and approximately 475 000 m^3/d (3.0 MMb/d) is heavy crude refining capacity (Figure 4.5). At one time, this market was not seen as one that held potential for western Canadian crude oil producers. However, recent interest has been generated with the reversal of the Mobil pipeline that will transport western Canadian crude

FIGURE 4.5

PADD III Receipts of Western Canadian Crude Oil – 2005



oil from Patoka, Illinois to Corsicana, Texas. In the first quarter 2006, deliveries on the Mobil line are expected to be 7 900 m³/d (50 Mb/d) versus its 10 300 m³/d (65 Mb/d) capacity. In April, the line was operating at capacity. During our consultations, producers were of the view that 63 600 m³/d (400 Mb/d) of heavy crude could possibly move into this market in the longer-term, possibly later this decade or post 2010.

PADD III is particularly attractive given the size and complexity of the refineries. Western Canadian crude oil, particularly bitumen blends, could compete in this market with imports from Venezuela and Mexico, particularly since it has recently been heavily discounted in the U.S. Midwest. Increased demand in this market would likely result in higher netbacks for Canadian heavy producers for two reasons: first, it would take volumes away from the Midwest market; and second, it could move the pricing parity point of heavy sour further south where Canadian heavy crudes would compete against other heavy oil imports.

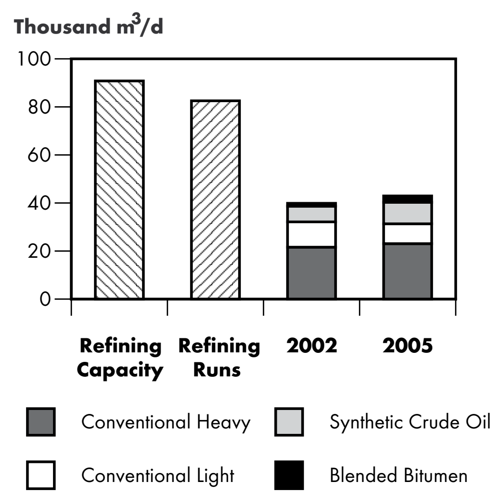
To ship the increased oil sands production to the U.S. Gulf Coast, Altex Energy Ltd. (Altex) announced in October 2005, the Altex Pipeline system, which would be a new direct-route, stand-alone oil pipeline that would deliver crude oil from northern Alberta to the U.S. Gulf Coast. This is discussed further in *Chapter 5 – Pipelines*.

4.3.1.4 PADD IV

PADD IV, with a refining capacity of 90 000 m³/d (567 Mb/d), has traditionally been a good market for western Canadian producers (Figure 4.6). Recently, however, the pricing dynamics in this market have changed. Refiners in this area have always been price takers because they have few supply alternatives. With the very high crude oil price, producers in PADD IV have been drilling at a record pace. As well, to extract additional oil, they are using CO_2 floods and horizontal drilling. This has resulted in an increase in crude production and pressure from domestic producers in PADD IV to process this production in local refineries. Subsequently, refiners in PADD IV are taking less western Canadian crude supplies in order to run the readily available and heavily discounted Wyoming sweet and sour crudes. The large discount is in reaction to aggressive Canadian crude pricing, shortage of refinery capacity and the lack of pipeline capacity to move the crude oil to other markets. Producers in this region will continue to be aggressive provided that crude oil prices remain above US$50 per barrel.

FIGURE 4.6

PADD IV Receipts of Western Canadian Crude Oil – 2005



In March 2006, Holly Corp. announced the sale of its Montana Refining Company, a partnership, to a subsidiary of Connacher Oil and Gas Limited. Montana Refining, located in Great Falls, Montana, operates a 1 300 m^3/d (8 Mb/d) refinery. It is anticipated that the refinery will provide Connacher with an outlet for the SAGD production from its Great Divide oil sands project, as well as, provide it with some protection against wide light/heavy differentials.

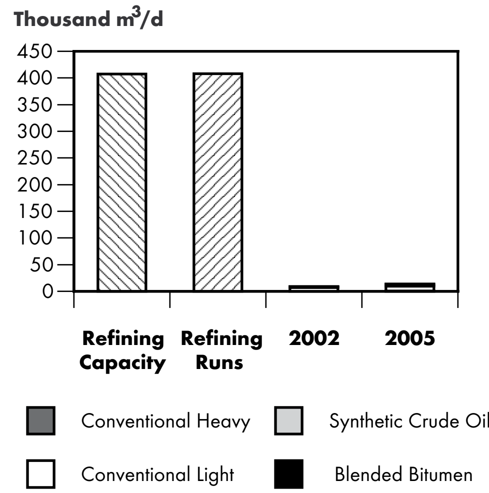
Due to its size and the complexity of the refineries, PADD IV will continue to be a marginal growth market for western Canadian crude oil, particularly SCO and blended bitumen.

4.3.1.5 PADD V

PADD V has a refining capacity of 403 000 m^3/d (2.5 MMb/d) and is a growth market for western Canadian crude oil. Consultations with industry indicated a strong consensus that this market, particularly Washington State, is eager for increased volumes of western Canadian crude oil. This is evident by the number of cokers and refinery conversions being contemplated in that market.

FIGURE 4.7

PADD V Receipts of Western Canadian Crude Oil – 2005



Refineries located in Puget Sound, such as ConocoPhillips, Tesoro and British Petroleum (BP) all have plans to run a heavier slate, which would include oil sands crude oil. Currently, Washington State processes only 11 percent of its crude oil requirements from Canada, and this is largely due to the availability of Alaskan North Slope (ANS) crude oil and capacity constraints on Kinder Morgan's Terasen Pipeline (Trans Mountain) Inc. (TPTM). A likely scenario in PADD V is that with the continuing decline in ANS crude oil production, western Canadian crude oil will push into the Puget Sound market, and ANS production will move farther south into California. The latest forecast of ANS is that production in 2006 is down almost seven percent from last year. The decline rate is higher this year as a result of the natural decline of maturing fields coupled with unanticipated field maintenance problems and unexpected delays in some development projects. Between 2008 and 2015, the production decline is expected to be 1.2 percent per year.

The California market could be an excellent market for heavier Canadian grades, but this would likely not occur until the end of the decade and would also depend on how the above scenario regarding the disposition of ANS production unfolds. This market could give Canadian producers another option and would also help to narrow the light/heavy differential by moving volumes away from northern PADD II.

4.3.2 *Other Export Markets*

In recent years, China's demand for oil has had a tremendous impact on global oil markets. It is now the world's second largest consumer of oil and the third largest importer. This is a result of strong growth in all sectors, but particularly transportation. In 2004, Chinese oil demand rose by 159 000 m^3/d (1.0 MMb/d), and this represents a 15 percent increase year-on-year. The reasons for this increase in oil demand include a strong GDP growth of around 10 percent; a strong industrial output estimated to be around 15 percent; an electricity shortage that supported domestic

T A B L E 4 . 3

Announced Refinery Expansions

Company	Location	Increase Crude	Coker or Expansion	Completion Date
Holly Corp.	Woods Cross, UT	10 Mb/d	Expansion	4Q2006
Coffeyville	Coffeyville, KS	15 Mb/d	Expansion	1Q2006
Tesoro	Anacortes, WA	15 Mb/d	Coker	2Q2007
Cenex	Laurel, MT	No increase	Coker (15 Mb/d)	1Q2008
Sunoco	Toledo, OH	50 Mb/d	Expansion	2008
Flint Hills Resources	St. Paul, MN	50 Mb/d	Expansion	1Q2008
Frontier Oil	El Dorado, KS	11 Mb/d	Expansion	2008
Frontier Oil	Cheyenne, WY	N/A	Coker	2008
Sinclair	Sinclair, WY	13 Mb/d	Coker	2008
United Refining	Warren, PA	5 Mb/d	Coker	2009
ConocoPhillips	Wood River, IL	55 Mb/d	Coker	2012–2015
ConocoPhillips	Borger, TX	25 Mb/d	Coker	2012–2015
ConocoPhillips	Ferndale, WA	25 Mb/d	Coker	2012–2015
ConocoPhillips	Billings, MO	N/A	Expansion	2012–2015

N/A – Not Available

oil use through increased utility use of fuel oil and off-grid/stand-alone generator use; increased petrochemical capacity; and strong growth in vehicle sales.

China will increasingly rely on oil imports because of its continued robust oil demand growth. Currently, about half of China's oil needs are met through imports of 556 400 m^3/d (3.5 MMb/d) and some analysts forecast this to rise to 1 589 800 m^3/d (10 MMb/d) by 2025. With the increased development of the oil sands, and the need for new markets, Canada would be in a position to export oil to China. Some analysts project that the light/heavy differential could narrow to the benefit of all Canadian producers, by moving crude oil to China. Enbridge's proposed Gateway pipeline which would deliver crude oil to the west coast of British Columbia, is trying to tap, amongst other markets, the Far East market, including China. Enbridge and state-controlled PetroChina have signed a memorandum of understanding to ship up to 31 800 m^3/d (200 Mb/d) on the Gateway pipeline, and it has been suggested that PetroChina could purchase a stake in the line. Industry is generally of the view, however, that filling up existing markets in the U.S. in the short-term makes sense and that the Far East has potential in the longer-term.

While much of the attention has been focused on China, a senior researcher at the Institute of Energy Economics in Japan estimated that Canada could export as much as 131 300 m^3/d (825 Mb/d) of sweet synthetic to Japan by 2015. Historically, Japanese refiners imported some bitumen, but found that it did not yield the lighter products they desired. It is likely that if Japanese refiners choose to import SCO it would have to be less expensive than the sour grades that they currently import from the Middle East.

Two state-run companies from India, Oil and Natural Gas Corp. and Indian Oil Corp. Ltd., have expressed an interest in spending one billion dollars on early-stage oil sands projects.

In addition, spot shipments of Canadian crude oil have been delivered to other markets. Most recently, there have been shipments to Italy. In the second quarter 2006, the Italian refiner, ENI, will begin construction on a 3 200 m^3/d (20 Mb/d) "Super Hydrocracker". It will have the ability to process residuals from heavy crude oil such as Russian Urals or Canadian heavy into high quality diesel. It should come on stream between 2007 and 2009 at ENI's largest mainland refinery at Sannazzaro, Italy. ENI has installed a smaller unit at its Taranto refinery that has tested Canadian oil sands crude oil.

4.4 Outlook: Issues and Uncertainties

It is expected that high oil prices, coupled with robust global oil demand, will continue to drive oil sands expansion. In this regard, producers will be faced with a number of hurdles including choosing among proposed pipelines to deliver the growing supplies to new and existing markets.

To penetrate new markets, there will likely be periods when substantial price discounts are required, particularly as new oil sands production comes on stream in large volumes and the market adjusts to the incremental supply.

Based on industry consultations and the Board's internal analysis, potential scenarios for market expansion for growing oil sands production could unfold in the following way:

Step One: Fill up existing markets, including Washington State, PADD II and PADD IV and some additional volumes in Canada.

Step Two: Further penetrate southern PADD II and PADD III and refinery expansions and conversions in northern PADD II, PADD IV and PADD V.

Southern PADD II could take an additional 6 400 m^3/d (40 Mb/d) with an expansion of the Spearhead pipeline and the U.S. Gulf Coast could take up to 63 600 m^3/d (400 Mb/d) of western Canadian crude if there were pipeline capacity to deliver those volumes. It is estimated that in the next 10 years, PADD II could take an additional 79 500 m^3/d (500 Mb/d). As well, in the near term, PADDs IV and V could take an incremental 6 400 and 7 900 m^3/d (40 and 50 Mb/d), respectively.

These increases to U.S. markets could take place in unison with expansions to offshore markets, as discussed in Step Three.

Step Three: The industry would have to branch out and develop new markets. In this connection, a new pipeline or a major pipeline expansion to the west coast would be required to deliver crude oil to California and the Far East.

With the expected increase in SCO production, there is also the opportunity of processing increased volumes in refineries in Ontario and reversing Enbridge Line 9 to supply Montreal refineries.

In addition to potential market opportunities, there are a number of issues and challenges through to 2015. They include:

- **Crude oil prices:** Very high crude oil prices have drawn a significant amount of attention to the oil sands, particularly from China, Japan, India and the U.S. Softening demand and falling prices could slow investment and hinder market development.
- **Bitumen blend versus synthetic:** The need for diluent to transport bitumen, and the uncertainty surrounding which market is best for producers continues to impact the pipeline selection process. There have been many announcements of upgrader projects which begs the question, when the North American refining industry appears to be moving toward processing heavier crudes, why is the industry moving to producing more light

synthetic crude oil? The uncertainty concerning the type of crude oil the industry will produce is causing delays in the decision-making process, leading to the likelihood that there will be extended periods of apportionment on the major pipelines. In other words, who should do the upgrading—the producer or the refiner?

- **Partnerships:** Those companies that are not integrated (i.e. upstream assets and downstream facilities) need to either enter into a supply contract or be in an ownership position in the corresponding asset. With the increased volumes that are expected to come on stream later in the decade, these arrangements are critical to market development to avoid large discounts.
- **Pipeline expansion:** Currently the major export pipelines are at or near capacity and at times in apportionment. The industry needs to decide which markets hold the greatest potential and move forward on pipeline expansions or new pipelines.
- **Light/heavy differential:** The light/heavy differential is expected to remain wide for the next several years until upgraders are built either upstream or at the refinery. Furthermore, growing international heavy crude oil production could have an affect on Canadian heavy crude oil prices.

MAJOR CRUDE OIL PIPELINES

5.1 Introduction

As discussed in *Chapter 3: Crude Oil Supply*, rapid expansion of the oil sands is expected to occur within the next decade while *Chapter 4: Markets* highlighted that markets will need to be determined. Pipeline infrastructure will need to be addressed to accommodate the increase in supply and market requirements. This chapter focuses on the major export pipelines and feeder pipelines, including announced expansions of existing pipelines and new greenfield projects.

In some instances, oil pipelines are embarking on a new era of contractual arrangements. Historically, oil pipelines, with the exception of Express, operated under common carriage. With the intense competition between announced pipeline proposals and refiners' need for security of supply, some pipeline companies are moving toward "take-or-pay" agreements with shippers to ensure there is support for these initiatives.

The number of proposed pipeline expansions and new proposals are causing delays within the industry's decision-making process. This coupled with environmental, Aboriginal and landowner concerns could delay pipeline development.

5.2 Crude Oil Pipelines

Canada delivers crude oil to the export market through three major Canadian trunklines (Figure 5.1):

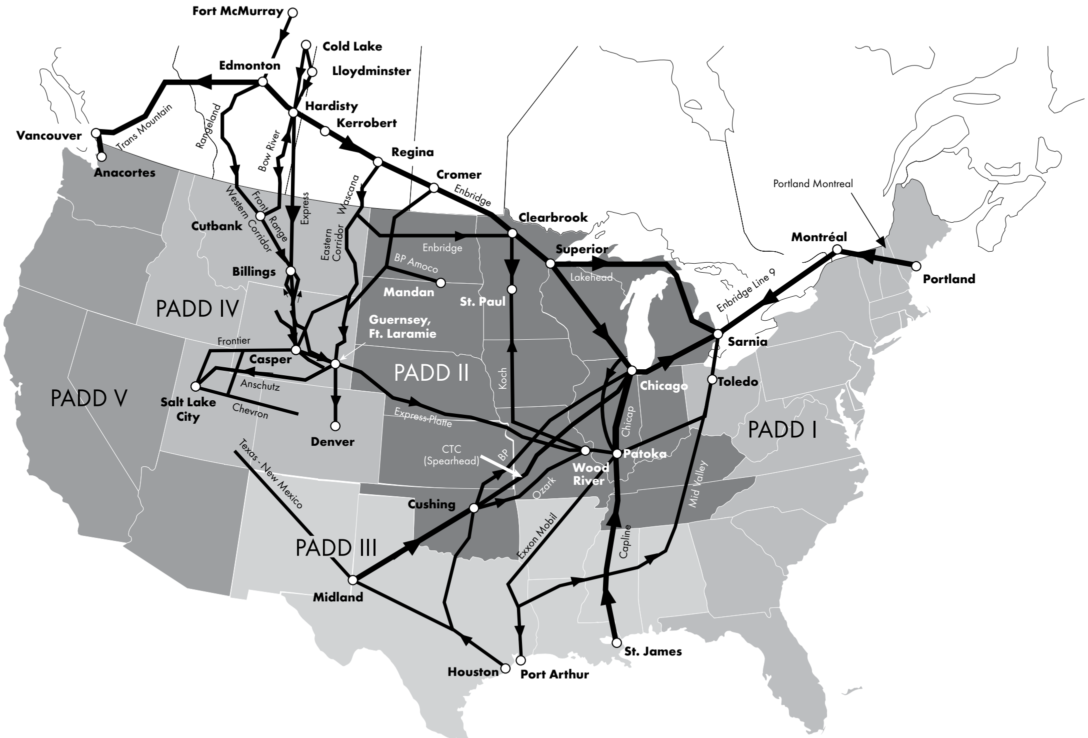
- Enbridge's mainline originates at Edmonton, Alberta and extends east across the Canadian prairies to the U.S. border near Gretna, Manitoba. At the U.S. border, it connects with the Lakehead system to deliver crude to the U.S. Midwest and north to Sarnia, Ontario.
- Kinder Morgan's Trans Mountain (formerly Terasen) pipeline originates at Edmonton, Alberta and extends west across British Columbia for delivery to Burnaby, British Columbia, the Westridge Dock and Washington State.
- Kinder Morgan's Express pipeline originates at Hardisty, Alberta and delivers crude to locations in PADD IV and connects to the Platte system in Casper, Wyoming for delivery to southern PADD II.

Enbridge Pipeline

The Enbridge system in Canada and the Lakehead system in the U.S. represent the largest crude oil pipeline in the world and the primary transporter of crude oil from western Canada to markets in eastern Canada and the U.S. Midwest. The system delivers approximately 333 000 m^3/d (2.1 MMb/d) of crude oil. In the third quarter 2005, to facilitate growth in heavy crude oil, Enbridge completed the Terrace Phase III expansion project. By converting Line 2 from heavy to light service, and Line 3

F I G U R E 5 . 1

Major Canadian and U.S. Crude Oil Pipelines and Markets



from light to heavy service, it increased its capacity to move heavy crude by 39 000 m³/d (245 Mb/d). In doing so, Enbridge reduced light capacity by 18 400 m³/d (116 Mb/d). Recently, Enbridge has been operating at or near capacity and in some instances certain lines have been under apportionment.

To accommodate growing oil sands production and the need for additional markets, Enbridge received approval for a non-routine adjustment for tolls to reverse two pipelines in the U.S. The Spearhead and Mobil 20-inch reversal projects will provide access to southern PADD II and the U.S. Gulf Coast, respectively. It is estimated that Spearhead will deliver 19 900 m³/d (125 Mb/d) versus signed commitments of 9 500 m³/d (60 Mb/d). Enbridge has indicated that it would respond to shipper requirements on Spearhead in the near-term to increase capacity to 30 200 m³/d (190 Mb/d), and in the longer-term, it has proposed a looping program with the first phase providing a further increase of 15 900 m³/d (100 Mb/d). The Mobil line made its first crude oil deliveries to the U.S. Gulf Coast in the first quarter 2006.

Kinder Morgan Express Pipeline

In April 2005, Express completed its expansion of 17 500 m³/d (110 Mb/d) to bring its capacity to 44 800 m³/d (282 Mb/d). Recently, the Express system has been operating at capacity and, at times, there has been apportionment on the Platte system. Kinder Morgan is assessing expansion plans to deal with capacity issues on the Platte system.

Kinder Morgan Canada Terasen Pipelines (Trans Mountain) Inc.

Trans Mountain pipeline transports crude oil and petroleum products from Edmonton to Vancouver, Washington State and offshore via the Westridge Dock. In November 2005, Kinder Morgan purchased Terasen Inc., making it a major oil pipeline player in Canada. Its current capacity is

35 700 m^3/d (225 Mb/d) and it has been operating at or near capacity for several years and, on many occasions, has been under apportionment. Kinder Morgan has carried forward Terasen's plans to expand the scale and the scope of the Trans Mountain system. The TMX project announced in 2004 comprises three phases, including an initial Anchor Loop expansion, followed by a southern or northern option. On 10 November 2005, part of TMX1, which included a capacity increase of 5 600 m^3/d (35 Mb/d), received approval from the NEB. This will increase the capacity from 35 700 m^3/d (225 Mb/d) to 41 300 m^3/d (260 Mb/d). On 17 February 2006, Kinder Morgan filed an application with the Board for the Anchor Loop project. The project involves twinning a 158 kilometre section of the existing line between Hinton, Alberta to a location near Rearguard, British Columbia. If approved, the Anchor Loop would add 6 400 m^3/d (40 Mb/d) of incremental capacity, bringing the Trans Mountain system to 47 700 m^3/d (300 Mb/d) by the end of 2008.

It is expected that Kinder Morgan could file the next phase of the TMX project in the first quarter 2007. TMX2 would involve the looping of the Trans Mountain pipeline from Edmonton to the Anchor Loop expansion (Hinton) and from the anchor loop (Rearguard) increasing capacity by 15 900 m^3/d (100 Mb/d) to 63 600 m^3/d (400 Mb/d). The in-service date is estimated to be January 2010.

The final phase of the project, TMX3, involves the completion of a south leg and/or a north leg. For both legs, capacity out of Edmonton would be 175 000 m^3/d (1.1 MMb/d). The south leg from Kamloops to Vancouver would add 47 600 m^3/d (300 Mb/d) and have a total capacity of 111 000 m^3/d (700 Mb/d). The north leg from Rearguard to Kitimat would have a capacity of 63 600 m^3/d (400 Mb/d). The in-service date for both legs is proposed for 2011.

Enbridge Southern Access

Enbridge has proposed the Southern Access program to expand and extend service on the mainline system. It would provide incremental capacity to Chicago, Wood River and Patoka and access to Cushing. In May 2006, Enbridge filed an application with the Board for Phase 1 of its Southern Access program to increase capacity by 19 000 m^3/d (120 Mb/d) with a scheduled in-service date of Fall 2006. The expansion would consist of debottlenecking and pump additions on Lines 3 and 4 from Edmonton and Hardisty, respectively. In the U.S., industry has decided to increase the pipe diameter from Superior to Flanagan/Chicago to 42 inches from the original proposal of 30 inches to reduce power costs and allow for future expansion. The initial capacity on the U.S. system would be 63 600 m^3/d (400 Mb/d) by early 2010 and expandable to 127 000 m^3/d (800 Mb/d). Enbridge continues to look at extending Southern Access to either or both Wood River or Patoka. Patoka offers more storage and better access to other pipelines and refineries.

Enbridge is assessing several other pipeline options from the Patoka area. They include expanding existing lines, such as Spearhead as well as reversing lines which could include, Seaway pipeline (Cushing to Houston); Ozark pipeline (Cushing to Wood River); and Mid Valley (Longview to Toledo).

Enbridge Southern Lights

The industry has been looking at alternatives to increase its diluent supply in Alberta. One initiative that Enbridge has been studying is the potential for diluent return service from the Midwest. Supply sources from this area could come from refineries, the U.S. Gulf Coast/Midcontinent, Rocky Mountain volumes and imports. In addition, the Southern Lights project would include an expansion of light crude oil capacity on the Enbridge mainline.

The Southern Lights Pipeline (diluent line) would include the reversal of Line 13 from Clearbrook, Minnesota to Edmonton, Alberta and new pipeline construction between Clearbrook and Manhattan, Illinois (near Chicago). The pipeline would have a total capacity of 28 600 m^3/d (180 Mb/d).

The expansion of light crude oil capacity on the Enbridge mainline would occur in parallel with the diluent return line. It would include an expansion of Line 2 between Edmonton and Superior, Wisconsin to 70 300 m^3/d (440 Mb/d) and construction of a light sour line from Cromer to Clearbrook of 29 500 m^3/d (185 Mb/d). This would eliminate the need for breakout storage tanks at Cromer.

Enbridge plans to synergize this project with the Southern Access Program. The project if approved could be in-service by the first quarter of 2009.

TransCanada Keystone Pipeline

In February 2005, TransCanada announced its Keystone Pipeline project. This is a 2 800 kilometre, 69 200 m^3/d (435 Mb/d) crude oil pipeline that would extend from Hardisty, Alberta to markets in the U.S. Midwest. TransCanada intends to convert one gas line in Canada to oil service and construct a new pipeline from the Canada/United States border to Wood River/Patoka, Illinois. On 31 January 2006, TransCanada announced that it had received long-term contractual commitments of 54 000 m^3/d (340 Mb/d). ConocoPhillips Pipe Line Company has signed a memorandum of understanding with TransCanada to acquire up to a 50 percent participating interest in the project, and ConocoPhillips has committed to ship crude oil on the pipeline. The proposal includes an expansion to 93 800 m^3/d (590 Mb/d) with the addition of pump stations.

Enbridge Alberta Clipper Pipeline

In February 2006, Enbridge unveiled its newest pipeline initiative, the Alberta Clipper. The proposal is for a 36-inch contract carrier crude oil pipeline that would have an initial capacity of 63 600 m^3/d (400 Mb/d), expandable to 127 200 m^3/d (800 Mb/d). The Alberta Clipper would run alongside Enbridge's mainline right-of-way from Hardisty, Alberta to Superior, Wisconsin and connect into existing infrastructure delivering crude oil into the Chicago area. The proposed in-service date would be 2010 or 2011.

Altex

Altex Energy is proposing to construct an oil pipeline from northeastern Alberta to the U.S. Gulf Coast by the fourth quarter 2010. It would have a minimum capacity of 39 700 m^3/d (250 Mb/d) with significant expansion potential. Altex has said that utilizing proprietary pipeline technology it could eliminate the need for condensate thereby greatly reducing the cost of transporting bitumen.

Enbridge Gateway Pipeline

Enbridge's proposed Gateway Pipeline would consist of two elements, a 63 600 m^3/d (400 Mb/d) crude oil pipeline and a 23 800 m^3/d (150 Mb/d) return condensate line. The crude oil line would originate in Edmonton for delivery to Kitimat and the condensate line would operate in the reverse direction, providing transportation for imported condensate. The crude oil and condensate lines could have ultimate capacities of 87 400 m^3/d and 39 800 m^3/d (550 Mb/d and 250 Mb/d), respectively. Both lines have a target in-service date of first half 2010.

Following the successful open seasons of both pipelines, Enbridge announced plans to increase the diameter of the condensate line to 20 inches and the crude oil line to 36 inches. Non-binding interest in excess of 63 600 m³/d (400 Mb/d) was received for the crude oil line. Enbridge has signed a memorandum of understanding with PetroChina to supply 31 800 m³/d (200 Mb/d) of crude oil to China. There have also been discussions that PetroChina may purchase a stake in the line.

Pembina Spirit Pipeline

In October 2005, Pembina Pipeline Income Fund (Pembina) and Terasen Pipelines Inc. announced a proposal to import 15 900 m³/d (100 Mb/d) of condensate into Kitimat and deliver it by pipeline to Edmonton. The proposal would utilize existing infrastructure and some new pipeline construction would be required. The proposed in-service date would be April 2009.

In February 2006, Pembina announced that it would pursue the Spirit Pipeline on its own, without the support of Kinder Morgan Canada (formerly Terasen Pipelines Inc.). Pembina announced in April 2006 that it has entered into a development support agreement with a group of shippers.

Conclusion

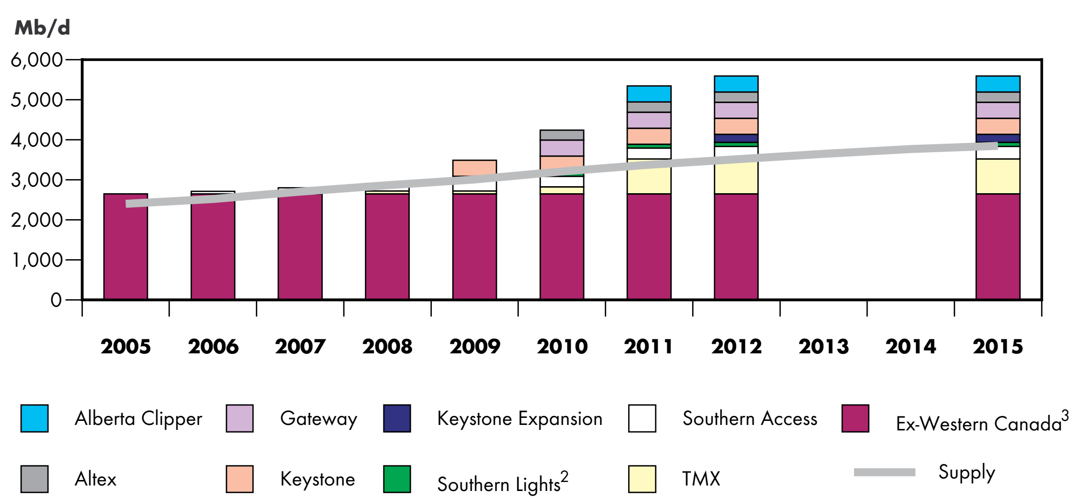
Figure 5.2 illustrates the production forecast for the Western Canada Sedimentary Basin (WCSB), the proposed pipeline projects, and the proponents estimated completion date. Based on the number of pipeline projects being proposed and the production that is forecast to come out of the WCSB, it is apparent that not all projects will move forward. However, as mentioned in *Chapter 4 – Markets* and as evident in the chart, pipeline capacity is expected to be tight starting in 2007.

5.3 Feeder Pipelines

In addition to the proposed expansions and greenfield projects announced by the major export lines, feeder pipelines within Alberta are expanding to transport growing oil sands volumes to the major hubs of Edmonton and Hardisty. These proposed expansions are described below.

FIGURE 5.2

NEB Supply Forecast and Proposed Pipeline Projects and Timing[1]



1 The pipeline projects are listed alphabetically.
2 Edmonton to Cromer.
3 Total pipeline capacity out of the WCSB.

Enbridge Waupisoo Oil Sands Pipeline

Enbridge announced in September 2005 that it will proceed with its proposed Waupisoo oil pipeline. The line would originate at Enbridge's Cheecham terminal on the Athabasca system and terminate adjacent to Enbridge's mainline Edmonton terminal. Initial capacity would be 55 600 m^3/d (350 Mb/d) with a maximum capacity of 95 400 m^3/d (600 Mb/d). It would also include a 16-inch return diluent line from Edmonton to the Fort McMurray area. If approved, the expected in-service date would be mid-2008.

The Waupisoo pipeline would be operated by Enbridge and shippers include, ConocoPhillips Canada, Petro-Canada, Suncor Energy and Total E&P Canada Ltd.

Kinder Morgan Corridor Pipeline

In August 2005, Terasen Pipelines (now Kinder Morgan Canada) announced plans to expand the Corridor pipeline. Currently, the Corridor pipeline system includes a 24-inch bitumen blend line and a 12-inch diluent return line. The proposed expansion includes building a new 42-inch bitumen line and upgrading pump stations along the existing system from the Muskeg River Mine north of Fort McMurray to Shell's Scotford upgrader near Edmonton. It would increase dilbit capacity to 79 500 m^3/d (500 Mb/d) by 2009 and would be designed to further support expansions in the future. It is estimated that future expansions of this system could lead to a capacity of 174 900 m^3/d (1.1 MMb/d).

Pembina Horizon Pipeline

In August 2005, Pembina Pipeline Corporation (Pembina) announced that it would twin the existing Alberta Oil Sands Pipeline resulting in two parallel, commercially segregated lines. One would be dedicated to Canadian Natural Resources (CNRL) and would transport synthetic crude oil from CNRL's Horizon project. The new line would connect with the existing infrastructure. It could be in-service by July 2008 and have a capacity of 39 700 m^3/d (250 Mb/d).

Pembina Cheecham Pipeline

In January 2006, Pembina announced that it had reached an agreement with ConocoPhillips Surmont Partnership, Total E&P Canada Ltd., Nexen Inc. and OPTI Long Lake L.P. for the construction of the Cheecham lateral pipeline. Pembina has entered into transportation agreements with shippers for up to 21 600 m^3/d (136 Mb/d). Construction is underway and the line is expected to be in-service by November 2006. It will transport synthetic crude oil for delivery to a terminal facility located near Cheecham, Alberta.

5.4 Outlook: Issues and Uncertainties

It is clear that increasing western Canadian production, driven largely by the oil sands has resulted in several proposed pipeline expansions or greenfield pipeline projects. The industry has some challenging times ahead with the increase in production and the resulting lack of capacity on the major export pipelines. The pace of pipeline expansion will largely depend on market conditions and the necessary regulatory approvals. In this regard, pipelines may be looking to shippers for financial support in the form of take-or-pay agreements.

It is expected that, if high prices continue and the market remains strong, apportionment on export pipelines will be an issue. In the short-term, the industry will add smaller incremental capacity expansions in an attempt to alleviate some of these capacity issues. Table 5.1 illustrates current expansion proposals that are either before the Board, have been publicly announced or are being considered by industry.

The next decade will be a critical period in terms of pipeline development. There are a number of issues and uncertainties that will impact the pace of expansion to 2015 including:

- **Crude oil prices:** See Chapters 3 and 4.
- **Bitumen blend, bitumen or synthetic:** Pipelines will need to be developed based on the type of oil sands crude oil that is produced and required by the market.
- **Cost of projects:** With the cost of labour and materials rising to unprecedented levels, project costs are rising at alarming rates. It is estimated that the costs of some pipeline projects have risen 25 percent since they have been announced.
- **Type of carriage:** Historically, oil pipelines have generally been common carriers, but there may be a desire by the project proponents to seek take-or-pay commitments.

TABLE 5.1

Announced and Potential Expansions by Canadian Pipelines

Pipeline	Potential Filing Date	Capacity Increase (Mb/d)	Proponents' Estimated Completion Date	Market
Terasen (TMPL)		75		PADD V
(Phase One TMX1)	Filed July 2005	35	April 2007	Offshore/Far East
(Phase Two TMX1)	Filed February 2006	40	Nov 2008	
Southern Option		700		PADD V
(TMPL TMX2)	01Q2007	100	Jan 2010	Offshore/Far East
(TMPL TMX3)	N/A	300	2011	
Northern Option (TMX)	N/A	400	2011	PADD V Offshore/Far East
Enbridge Gateway (oil/diluent)	June 2006	400/150	Mid 2010	PADD V Offshore/Far East Alberta (diluent line)
Pembina Spirit (diluent)	N/A	100	April 2009	Alberta
Enbridge Southern Lights				
Southern Lights (diluent)		180		Alberta
Line 2 Expansion (oil)	N/A		2009	
Edmonton to Cromer		103		PADD II
Cromer to Clearbrook		33		PADD II
Clearbrook to Superior		33		PADD II
New sour line Cromer to Clearbrook		185		PADD II
TCPL (Keystone)	June 2006	400	2009	Southern PADD II/ PADD III
Alberta Clipper	N/A	400	2010/11	Southern PADD II
Altex Energy	N/A	250	4Q2010	PADD III
Enbridge (Southern Access)		315		Midwest/Southern PADD II
Phase I	May 2006	120	Oct 2006 and Feb 2007	
Phase II	N/A	148	2008/09	
Phase III	N/A	47	N/A	

N/A – Not Available

ENVIRONMENT AND SOCIO-ECONOMIC

6.1 Introduction

The economic potential of Canada's oil sands is undisputed, but the fast pace and large scale of its development has considerable environmental and social impacts. This chapter provides an update on the major challenges oil sands operators must confront, including: water conservation, greenhouse gas (GHG) emissions, land disturbance and waste management. From a socio-economic perspective, one major issue of concern is an overwhelming demand on a limited population of skilled labourers. Regions associated with oil sands development enjoy several economic benefits but these benefits are accompanied by costs to the social well-being of the communities.

A variety of regional multi-stakeholder groups have been established to address the socio-economic and environmental impacts related to oil sands development. Table 6.1 shows a representation of these major groups. Many subcommittees have also been formed to address issues under their jurisdictions. These groups include industry, government and local community partnerships that work to create policies and programs for the best management of the resource.

6.2 Environment

The concern around the management of environmental impacts related to developing the oil sands has reached new highs. In March 2006, the Parkland Institute released a report calling for a moratorium on oil sands development for five years, citing the need for Canadians to discuss and understand all the implications.

TABLE 6.1

Multi-Stakeholder Summary

Stakeholder	Focus
Wood Buffalo Environmental Association (WBEA)	• Air quality monitoring in the Wood Buffalo Region • Ecological and health effects monitoring
Cumulative Environmental Management Association (CEMA)	• Addresses cumulative effects of regional development in northern Alberta
Canadian Oilsands Network for Research and Development (CONRAD)	• Research and development in responsible environmental activities and emission reduction opportunities for mining and in situ projects
Athabasca Regional Issues Working Group (RIWG)	• Provide a proactive process that promotes the responsible, sustainable development of resources within the Regional Municipality of Wood Buffalo for the benefit of all stakeholders

6.2.1 Water Use and Conservation

Both mining and in situ operations use large volumes of water for extracting bitumen from the oil sands. Between 2 to 4.5 barrels of water[iii] are withdrawn, primarily from the Athabasca River, to produce each barrel of synthetic crude oil (SCO) in a mining operation. Currently, approved oil sands mining projects are licensed to divert 370 million cubic metres (2.3 billion barrels) of freshwater per year from the Athabasca River[iv]. Planned oil sands mines would push the cumulative withdrawal to 529 million cubic metres (3.3 billion barrels) per year[v]. Despite some recycling, almost all of the water withdrawn for oil sands operations ends up in tailings ponds.

Stakeholders agree that the Athabasca River does not have sufficient flows to support the needs of all planned oil sands mining operations. Adequate river flows are necessary to ensure the ecological sustainability of the Athabasca River. In winter, river flows are naturally lower[vi] with low rates of precipitation, and therefore, water withdrawal during this period is of particular concern.

In January 2006, Alberta Environment (AENV) issued *An Interim Framework: Instream Flow Needs and Water Management System for Specific Reaches of the Lower Athabasca River* to address this issue. This document describes certain actions to be taken under various flow conditions. Under conditions where there could be potential short-term impacts on the ecosystem, project owners are asked to target their diversion rate to less than 10 percent of available flow. Recent and new licenses may include conditions with mandatory incremental reductions. In cases where flows are so low that withdrawal would have expected impacts on the aquatic ecosystem, water use reductions and the use of water storage would be mandatory.

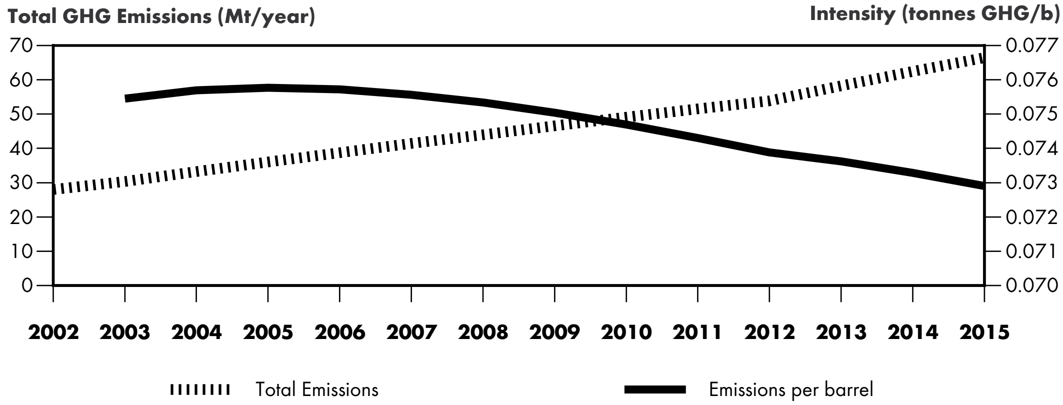
Oil sands mining operations have direct impacts on groundwater levels. Once the mine pit is excavated, it is essential to reduce groundwater levels in the area to prevent flooding of the pit. Withdrawal of groundwater from large areas of the landscape can lower the groundwater level in adjacent areas, which can result in reduced groundwater flows to peatlands, wetlands and other surface waterbodies.

About 82 percent[vii] of Alberta's remaining established oil sands reserves can only be accessed using in situ extraction technologies, and there is also a growing demand for freshwater for these projects. The demand for fresh water for in situ oil sands projects is projected to more than double between 2004 and 2015 from 5 million (31.5 million barrels) to 13 million cubic metres (82 million barrels) per year[viii]. In SAGD operations, 90 to 95 percent of the water used for steam to recover bitumen is reused, but for every cubic metre (6.3 barrels) of bitumen produced, about 0.2 cubic metres (1.3 barrels) of additional groundwater must be used[ix]. SAGD projects minimize the use of freshwater aquifers by using some freshwater mixed with saline groundwater. However, treating saline groundwater for the steam generators produces large volumes of solid waste. The disposal of this waste to landfills is another long-term concern because it could impact nearby soil and groundwater. This waste has a high concentration of acids, hydrocarbon residues, trace metals and other contaminants.

AENV is currently developing a new Water Conservation and Allocation Policy to reduce or eliminate the use of freshwater for in situ projects. Water allocation licenses will be issued for a two-year period with subsequent licenses issued for a five-year term, if the renewal is allowed. This is a reduction from the previous 10-year renewal period. License holders must apply for renewal under section 59 of the *Water Act*. AENV will approach the holders of permanent licenses to undertake a voluntary review of their licence.

FIGURE 6.1

Projected GHG Emission from Oil Sands to 2015



Source: Pembina Institute. *Oil Sands Fever – The Environmental Implications of Canada's Oil Sands Rush*

6.2.2 Air Emissions

While there remains a controversy over our ability to manage global climate impacts of greenhouse gas (GHG) emissions, many Canadians are concerned about GHG emissions. The production of bitumen and SCO emits higher GHG emissions than the production of conventional crude oil and has been identified as the largest contributor to GHG emissions growth in Canada.

Although significant progress has been made toward decreasing the intensity of GHG emissions produced by oil sands operators, additional production offsets these gains and total emissions are expected to rise. Figure 6.1 shows projected emissions, with total emissions estimated to be 67 megatonnes (Mt) per year by 2015 under Pembina Institute's second best scenario[x].

Carbon Dioxide

Innovative technology applied to increasing energy production has the potential to both reduce GHG emissions and create an economic opportunity. Research is being conducted to determine the feasibility of CO_2 capture and storage in Canada. According to the Alberta Geological Survey, the cumulative capacity of oil and gas reservoirs located in western Canada with an estimated CO_2 sequestration capacity greater than 1.0 Mt each is 3.2 gigatonnes CO_2 for gas reservoirs and 560 Mt for oil reservoirs[xi].

Carbon dioxide flooding in mature oil reservoirs for enhanced oil recovery (EOR) could increase production from mature Canadian oil reserves by between 8 and 25 percent, which means increasing potential recovery by between 0.5 and 1.4 billion cubic metres (3 and 9 billion barrels) of oil[xii]. At current oil prices, there is renewed interest in EOR projects but the economics are still marginal. Carbon dioxide injection for enhancing coal bed methane (CBM) recovery has also generated much interest but is currently much less economic than for EOR.

The oil sands projects are a major source of CO_2, but a dedicated CO_2 pipeline from Fort McMurray to the large light oil or CBM pools in central Alberta will be needed to encourage the capture, storage and use of large volumes of CO_2. A number of provincial and federal government incentives are in place to promote the development of CO_2 capture and storage, but the uncertainty of policy regarding long-term storage is an obstacle.

6.2.3 Land Disturbance and Reclamation

The Athabasca oil sands deposit is situated wholly within Canada's boreal forest. Individual mine sizes range from 150 to 200 square kilometers (58 to 77 square miles). The proposed future reclaimed landscape will be significantly different—with 10 percent less wetlands, more lakes, and no peatlands. There are currently divergent views regarding the ultimate the success of reclamation methods. The in situ process requires no excavation and less surface area for operation but is associated with fragmentation of the forest from the construction of new roads in the area, seismic lines and exploration well sites. As well, there is still some debate about whether the tailings ponds can become biologically productive ecosystems.

6.2.4 Sulphur By-product

Elemental sulphur is a major by-product of the oil sands. There have been notable efforts focused on the management of sulphur. The stockpiling of sulphur is a physical problem. By 2015, sulphur recovery could generate as much as five million tonnes of sulphur per year. To address this issue, China and India have been identified as potential markets since sulphur can be used to make fertilizer. Shell Canada has made investments to market Canadian sulphur as a replacement for the process of burning pyrite to extract sulphur. Since 1996, 40 of China's 600 fertilizer plants have been converted to use Canadian sulphur, as opposed to burning pyrite to extract sulphur, thereby releasing 250,000 fewer tonnes of CO_2 to the atmosphere each year[xiii]. Sulphur is also currently used in road asphalt and potentially in concrete or other construction materials.

6.3 Socio-Economic

The Athabasca deposit is the largest of the three oil sands deposits in northern Alberta and has undergone the most intensive oil sands development. Development in the Cold Lake and Peace River regions has been less extensive to date; however, this is starting to change. These regions will likely face socio-economic impacts similar to the Athabasca region in the future. It will require a concerted effort from all of the stakeholders to effectively address socio-economic concerns as the oil sands enter into a period of unprecedented growth.

Industry, government and local organizations are working to improve the social well-being of Aboriginal and non-Aboriginal communities in the region. These efforts must continue in order to keep pace with the increasing demands that will be placed on the existing social infrastructure. This should be supplemented with careful planning to ensure that no irreparable damage is done to people or the environment and that natural resources are developed in a responsible manner taking into account the needs of future generations.

6.3.1 Socio-Economic Setting

The 2005 Municipal Census results indicate that the Regional Municipality of Wood Buffalo[xiv] has a population of 73,176. This figure represents an increase of 6,071 residents or nine percent since the municipal census in 2004. The Sustainability Community Indicators Summary Report indicated that the population of Fort McMurray and the Regional Municipality of Wood Buffalo has a higher growth rate, a higher net migration rate, a higher proportion of males, and is generally younger than the selected comparator communities/regions of Alberta. This steady population growth has the potential to exacerbate socio-economic impacts.

According to NEB estimates, $41 billion has already been invested in Canada's oil sands, $7 billion is projected to be spent on construction in 2006, and another $85 billion worth of projects are forecasted for completion by 2015. Presently, oil companies and developers are engaged in or have proposed 46 oil sands related projects with 135 project expansion phases. This magnitude of growth and expansion of the oil sands is not possible without a corresponding increase in the number of workers.

Labour

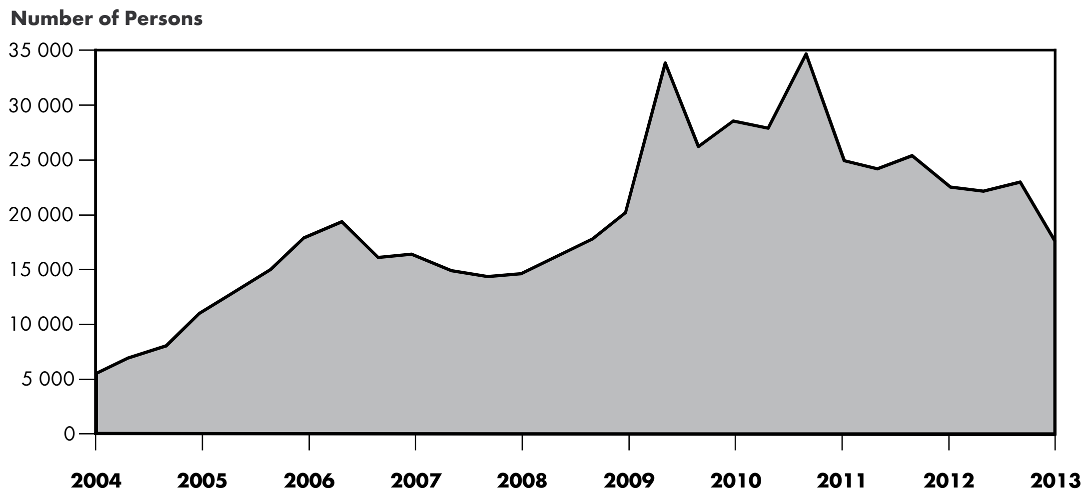
There is currently a limited supply of skilled workers in Alberta, and this tight labour market is expected to continue in the near future. The Construction Owners Association of Alberta states that labour supply and demand forecasts show increased construction activity in Alberta, especially in the oil sands, which will cause severe shortages of construction labour in the years ahead[xv]. Figure 6.2 illustrates the expected increase in the number of construction personnel that will be required for Alberta industrial projects with a planned capital expenditure greater than $100 million. Major industrial projects in Alberta will be competing for labour, and this competition has the potential to drive up construction costs and pull workers from other parts of Canada.

A labour shortage occurs when the demand for workers exceeds the supply of those qualified, available and willing to do the job at existing market conditions, including prevailing wages and locations. The challenge for the oil sands sector is not only one of finding the right skills—process operators, heavy equipment operators, mechanics and plant maintenance personnel—but also attracting these people to the Wood Buffalo region[xvi].

To address the current pressure on labour supply from several industries in Alberta, the Government of Alberta released a preliminary strategy in January 2006, *Building and Educating Tomorrow's Workforce: A Framework to enhance Alberta's People Capacity*. This 10-year strategy is currently in the consultation phase but outlines various proposed actions to address Alberta's labour force challenges. The strategic framework is built around four themes—inform (education, career, workplace and labour market information), attract (immigrants and inter-provincial migrants), develop (education and training investment) and retain (community and work attractiveness)[xvii]. Addressing the labour force shortages faced by the oil sands industries is a priority for the Government of Alberta, and as a result, the

FIGURE 6.2

Construction Personnel Required for Alberta Industrial Projects Costing Over $100 Million



Source: Construction Owners Association of Alberta (COAA)

10-year strategy includes an Oil Sands Industry Sub-Strategy. The Alberta Government has also signed an agreement with the federal government that will allow for the targeted entry of temporary foreign workers to meet the urgent skilled labour needs of oil sands employers for key projects in Fort McMurray[xviii].

6.3.2 *Positive Socio-Economic Impacts*

There are numerous positive socio-economic impacts on the communities and regions associated with oil sands development, including employment, economic benefits, economic stability, government revenue, and investment in research and development. This update will highlight employment, and government revenue and national economic benefits.

Employment

In addition to the 33,000 direct, indirect and induced jobs already created by oil sands development, it is expected that there will be a total of 240,000 new jobs created across Canada by 2008[xix]. Roughly 60 percent of these jobs will be in Alberta, with the majority in the manufacturing sector.

Oil sands companies in the Wood Buffalo region have projected that they will be hiring approximately 6,000 new permanent positions from 2005 to 2014. An additional 9,000 will be required to replace workers lost due to attrition. In 2004, over 1,300 Aboriginal people were directly employed by oil sands developers or have been engaged by contractors, and more than $250 million was spent on contracts to source goods and services from businesses owned by Aboriginal people.

Government Revenue and National Economic Benefits

Oil sands industry expansion is a major driver of economic activity in Alberta, which in turn generates economic benefits for the regional, provincial and national economies. Oil sands royalties and taxes generated for the Alberta government between 1996 and 2005 totalled $6 billion. The Athabasca Regional Issues Working Group[xx] forecasts the following:

- by 2015, the Alberta government is expected to receive $2.4 billion annually in royalties, Alberta corporate tax and personal income tax from existing and new oil sands projects; and
- by 2015, the federal corporate and personal tax revenue associated with the oil sands industry is estimated to be $3.5 billion per year.

6.3.3 *Negative Socio-Economic Impacts*

There are also negative socio-economic effects associated with this rapid growth. These negative effects include a shortage of affordable housing, increased regional traffic, increased pressures on government services such as health care and education systems, alteration to the traditional way of life, impacts on traditional lands, municipal infrastructure that lags behind population growth, drug and alcohol abuse, and increased dependence on non-profit social service providers. The following highlights housing, and infrastructure and services issues:

Housing

The growing population of Fort McMurray creates a demand for housing, resulting in high accommodation costs, low availability and a lack of subsidized housing. A key finding in the Sustainable Community Indicators Summary report[xxi] regarding the availability of housing is that housing is generally less available in Fort McMurray than the communities of Grande Prairie, Medicine Hat, Calgary and Edmonton. The report also found that the housing situation is worsening (i.e., the availability of housing in Fort McMurray is decreasing).

In the Wood Buffalo region, and especially in Fort McMurray, this affordability and availability issue is acute because:

- housing prices are high relative to Edmonton and elsewhere, with the average price of a single family dwelling costing $430,000 for the month of March 2006[xxii] compared to $256,000 in Edmonton[xxiii] and $363,000 in Calgary[xxvi]; and
- rents are high with a two-bedroom apartment costing on average $1,400 per month[xxv] in February 2006. In addition, vacancies are extremely low, and recent new project announcements have resulted in notices of further rental increases.

The affordability and availability of housing in Fort McMurray is detrimental to recruitment for oil sands companies. In order to address these issues, several companies have applied for fly-in and fly-out permission for their projects, which would allow workers to live in larger centres (e.g., Edmonton, Calgary and other centres in Canada) and commute to the worksite via airplane. This approach has the potential to assist companies with recruitment and reduce stress on accommodation, infrastructure and services; however, in the long-term this approach may compromise the sustainability of communities (i.e., Fort McMurray and other centres in Canada).

Infrastructure and Services

The Wood Buffalo Business Case 2005 offers a comprehensive overview of the urgent public infrastructure needs of the region as determined by industry, the municipality and public service providers. A capital investment of $1.2 billion is required to address the full range of public sector infrastructure needs in the region over the next five years[xxvi]. The $1.2 billion includes:

- $353 million in municipal projects, including water, waste water, road and recreation facilities;
- $236 million in primary, secondary and post-secondary education facilities;
- $500 million in highway projects; and
- $136 million in health facilities and affordable (low income) housing.

6.4 Outlook: Issues and Uncertainties

The original goal of producing one million barrels per day of oil from the oil sands by 2020 was surpassed in 2004. In light of such rapid growth, the question arises as to whether the balance between resource development and environmental protection and social interests can be maintained. The following are the key environmental and socio-economic challenges to be addressed.

- **Water policies:** The amount of water used in oil sands mining operations is significant and the limited available supply from the Athabasca River could be a constraint on future expansion plans. Continued development of water policies beyond AENV's Interim Framework can be expected. Some newer approved oil sands mines have up to 30 days of on-site water storage incorporated into their project designs to limit withdrawals during periods of low river flows. Building water storage[xxvii] upstream of the oil sands mine operations to help supplement periods of low river flows is another option.
- **Labour requirements:** Both short-term and long-term solutions have been proposed to help meet the labour needs of oil sands industry employers. It remains uncertain if the

short-term solutions will be able to increase the supply of skilled workers in order to match the demand created by the rapid expansion of the oil sands industry. A limited supply of skilled labour has the potential to restrict the pace of development.

- **Infrastructure and services:** As a result of rapid population growth, the Wood Buffalo region has experienced deficiencies in community service delivery and infrastructure development. This jeopardizes the ability of the Regional Municipality of Wood Buffalo to maintain a reasonable quality of life standard, which is essential for all employers in the region that seek to attract and retain employees.
- **Air emissions:** GHG emissions are a major concern for Canadians. Oil sands operators have taken steps to significantly reduce the emissions intensity of their operations but total emissions have still increased due to higher production levels. The use of CO_2 for enhanced oil recovery could potentially reduce GHG emissions and create an economic opportunity.
- **Cumulative environmental impacts:** The accumulation of changes to the air, land and water, which results from oil sands development, is a major area of concern. Environmental groups contend that there is currently inadequate scientific information to understand how the ecosystem will react to the impacts of development and that stricter environmental performance targets are needed. Industry continues to look at technological innovation that could be used to reduce environmental impacts.
- **Technology:** With continued high oil prices, the oil sands industry could be motivated to focus their innovative capacity on technological breakthroughs for the environment. In terms of waste management, gasification could potentially turn petroleum coke into fuel gas and a source of hydrogen. CO_2 sequestration (injecting CO_2 from oil sands into conventional oil fields) promises to both capture emissions and add new crude production. There are many areas for companies to devote their capital, depending on the incentives.

ELECTRICITY OPPORTUNITIES

7.1 Introduction

Cogeneration plants, also known as a combined heat and power (CHP) facilities, are the primary source of power for most oil sands operations. CHP facilities typically use natural gas as fuel to run a combustion turbine that turns a generator to produce electricity. A heat recovery steam generator then captures the heat that would normally be wasted and uses it to produce steam, hot water or a mixture of the two for use in an industrial process such as bitumen production. This combined process is more cost and fuel efficient than generating equivalent amounts of electricity and steam separately.

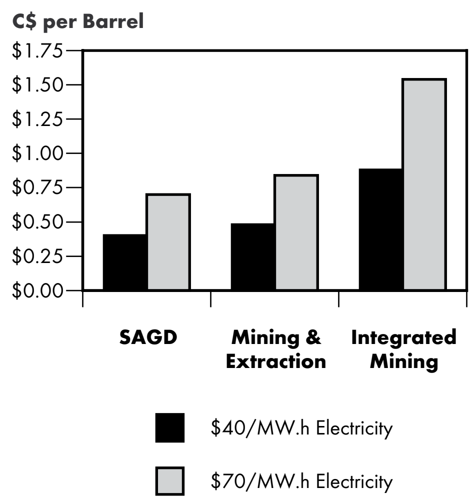
Developments in the oil sands industry since 2004 have led the majority of oil sands producers to continue to install cogeneration plants at their facilities to:

- increase the reliability of steam and power in order to maximize oil production;
- capture environmental and economic efficiencies, and;
- potentially increase revenues with the sale of excess power.

However, the current trend has shifted to building only sufficient cogeneration to ensure the facility can meet its own energy needs, but with little surplus available for sale to the grid.

F I G U R E 7 . 1

Estimated Electricity Costs by Recovery Type



Source: CERI and AESO

7.2 Electricity Requirements

Increased prices for natural gas have raised the Alberta average electricity pool price in 2005 to $70/MW.h from the $40/MW.h used in the Board's 2004 report, as shown in Figure 7.1. While this represents a 75 percent increase in electricity costs, the resulting increase to production costs is small in comparison to the increase in oil prices. Consequently, more weight is placed on maximizing production than in generating revenue from excess electricity sales or reducing electricity costs.

7.3 Cogeneration Opportunities

Total Alberta generating capacity, as of March 2006, is about 11 400 MW, while the peak demand, set in December 2005, was 9 580 MW[xxviii].

Installed total cogeneration capacity increased by about 150 MW in 2005, of which about 25 MW is available for sale to the grid. The latest Athabasca Regional Issues Working Group cogeneration forecast (mid-range) is illustrated in Figure 7.2. The capacity forecast in 2015 lies in a range between 2 900 MW and 3 000 MW.

This forecast is significantly lower (projected total generation capacity in 2015 is 22 percent lower) than in the Board's 2004 report because of higher natural gas prices and concerns about the uncertainty surrounding the amount of energy the Alberta electricity market can absorb. These factors have led to a trend for oil sands producers to build cogeneration for self-sufficiency, not for grid sales. Specifically, instead of building cogeneration to the steam requirements of a project, facilities are sized based on the project's electricity requirements with the addition of less capital-intensive steam boilers for additional steam needs.

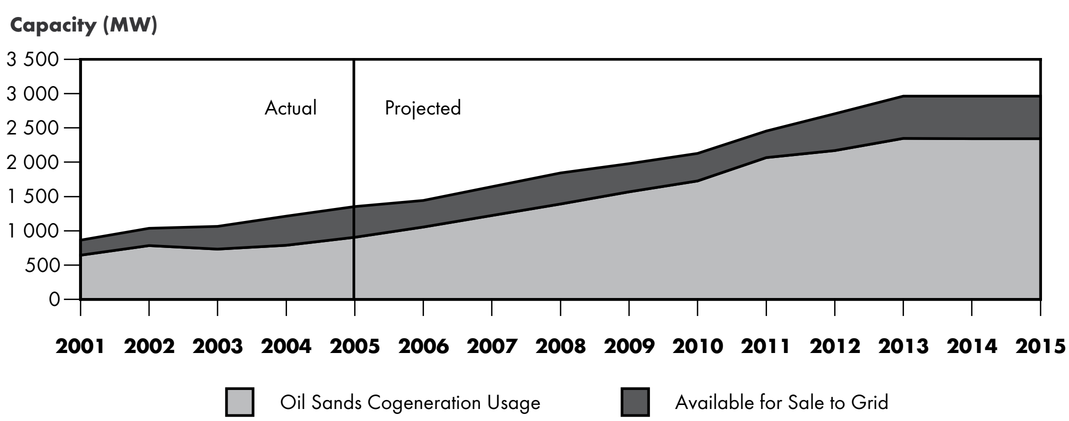
Higher natural gas prices have led to a heightened interest in coal-fired generation in southern Alberta as well as increased interest in alternative fuels such as coal and bitumen. The direct combustion of coal and bitumen can be used to fuel boilers but is not suitable for cogeneration. Recent developments in in situ recovery technologies such as low pressure SAGD or solvent assisted production, or new recovery methods such as VAPEX or THAI, could also reduce the need for steam generation. Any technology that reduces the need for steam will decrease the potential for cogeneration, as cogeneration is only economic when there is a need for the steam produced.

However, renewed interest in cogeneration could result if:

- the potential market in power attributes[xxix] became more favorable—specifically if the market was willing to pay a premium for clean power;
- an alternative fuel to natural gas, such as syngas[xxx] (produced from the gasification of coal, bitumen or petroleum coke) can be used since it would remove the uncertainty associated

FIGURE 7.2

Oil Sands Based Cogeneration



Source: Athabasca Regional Issues Working Group. *2006 Oil Sands Co-generation Report.*

with high natural gas prices; and

- Alberta electricity could gain access to larger, higher priced markets, such as California.

Farther out on the horizon is the possibility of using nuclear energy in the oil sands. Higher natural gas prices would favour the development of this technology; however, certain issues will have to be addressed before nuclear energy could be part of the oil sands industry. These include the large size of a typical nuclear generator compared with a typical oil sands plant, the oil sands producers' lack of experience with the technology, and public concerns about safety and the disposal of nuclear waste.

Research continues and, while it is unlikely to see commercial development in the time frame of this report, it may be possible to develop smaller, low maintenance modular nuclear reactors that would address some of these concerns.

7.4 Transmission

The Alberta Transmission Development Policy, announced in December 2003, has generally been seen as successful in addressing many of the concerns regarding the development of new transmission in a timely manner.

The addition of a third 240 kV transmission line in the Fort McMurray region has raised transmission capacity to 610 MW and has enabled the removal of Remedial Action Schemes (RAS), which were previously required to deal with the possibility of a line fault. Oil sands producers have welcomed this addition since it reduces the risk of service interruption, which could result in lost production, and it has allowed access to the Alberta market for cogeneration surpluses. If more cogeneration surplus becomes available in the future, further transmission expansion will be required in order to reach the market.

Work continues on the development of the proposed Northern Lights project to connect Fort McMurray cogeneration to markets in California. The consensus remains that while the project has great potential there are also a number of questions that must be answered, such as:

- How big is the potential market? Will nuclear and coal plants in California and the Pacific Northwest be retired or refurbished? Will there be competition from coal-fired generation in the U.S. states east of the Rockies?
- Who will take the risk of being the first company to commit to the project? Will it be the transmission provider or a producer?

7.5 Outlook: Issues and Uncertainties

There are many factors that will affect the future of oil sands related cogeneration. Some of the most important are:

- **Natural gas costs:** Rising natural gas prices have caused increased interest in coal-fired generation in southern Alberta, which can present serious competition for natural gas-fired cogeneration.
- **Technology:** Natural gas prices have given impetus to the development of new technologies for oil sands production. Alternate fuels such as syngas, that can be used to produce electricity and steam, will favour cogeneration. However, fuels that can be used in

a boiler but not in a combustion turbine, such as bitumen and coal, or oil sands production technologies that reduce the demand for steam such as THAI or the use of solvents, will reduce the potential for cogeneration.

- **Availability of markets:** The Alberta electricity market has relatively low cost generation and is small compared to the potential for cogeneration in the Fort McMurray region. Access to larger, higher priced markets in California would make a major difference in how much cogeneration is built.
- **Power attributes:** If consumers are willing to pay a premium for clean power, this would favour development of cogeneration. Natural gas-fired cogeneration uses a clean fuel very efficiently. The production of syngas has more environmental costs but is still cleaner than coal fired generation and (due to higher efficiencies) almost as clean as combined cycle natural gas generation.

Petrochemical Feedstock Opportunities

8.1 Introduction

Alberta's petrochemical industry is based on ethane (which is produced from processing natural gas) as feedstock for the production of ethylene. In response to flattening natural gas production from the WCSB and rising demand, natural gas prices, and therefore ethane prices, have increased significantly since the late 1990s. Since feedstock costs account for over two-thirds of the total cost of producing ethylene, they have a strong influence on operating profitability. Going forward, with natural gas prices expected to remain high and volatile (over US$7 per MMBtu), natural gas-based feedstock costs are also expected to remain high.

The Alberta petrochemical industry has suggested that current ethane feedstock supply falls short of ethane cracker capacity by about 4 800 m^3/d (30 Mb/d). Given the expected outlook for conventional natural gas supply, the ethane supply shortfall could intensify if WCSB conventional natural gas production declines or if domestic gas demand in the province increases. In addition, North American ethylene derivative demand is forecast to grow to the point where new ethylene capacity will likely be required within five to ten years. In order for the Alberta ethylene sector to expand, additional, secure and cost-competitive feedstock supply will be required. These feedstock challenges have highlighted the need to consider future ethane supply and feedstock flexibility.

Over the past few years, market signals have indicated that Alberta's oil sands resource could provide a secure, substantial and stable-priced feedstock for the petrochemical industry. Currently, most of this potential feedstock is not recovered but is used as fuel in upgrading and refinery operations.

8.2 Synthetic Gas Liquids (SGL) from Upgrader Off-gas

When bitumen is upgraded to produce SCO, the upgrading processes produce a by-product off-gas, which is a mixture of hydrogen and light hydrocarbon gases (including paraffins ethane, propane and butanes; and, using the coking process, olefins ethylene, propylene and butylenes). The paraffinic light hydrocarbon components of off-gas, ethane in particular, could be a potential source of feedstock for the Alberta ethylene plants. The olefin portion could be feed for petrochemical derivative plants. This mix of paraffinic and olefinic hydrocarbons is referred to as "synthetic gas liquids" or "SGL". They currently remain, for the most part, in the off-gas and are consumed as fuel.

Upgrading bitumen also represents potential petrochemical feedstock in the form of heavier intermediary products recovered from upgrader and refinery processes. The intermediary products include naphtha, aromatics and vacuum gas oil (VGO). Access to oil sands intermediary hydrocarbon feedstock would likely require association with an integrated upgrader/refinery/petrochemical complex. Development of such a complex is expected to be beyond the timeframe of this report. Consequently, intermediary feedstocks will not be discussed in this report.

8.2.1 Ethane and Ethylene ($C_2/C_{2=}$)

Based on production from existing and currently proposed upgrading expansions, it is estimated that by 2012, up to at least 16 000 m^3/d (100 Mb/d) of SGL mix could be entrained in upgrader off-gas. About 50 percent of this stream would be ethane. Existing and proposed upgrading expansions (for the purpose of determining this supply) would include Syncrude Canada Ltd., Shell Canada Ltd. and Suncor Energy Inc. (Suncor), as well as two other upgraders in operation by 2012. Tying in SGL streams from refinery processes could further increase the potential.

Alberta currently has upgrader off-gas C_{3+} extraction facilities near Fort McMurray, as well as a propane/propylene splitter facility located at Redwater, Alberta. A portion of the province's currently available olefinic C_{3+} mix is extracted from Suncor's upgrader off-gas. The Suncor off-gas stream could also provide about 1 900 m^3/d (12 Mb/d) of $C_2/C_{2=}$ mix; however, it is not economic to recover at this time. As a result, $C_2/C_{2=}$ mix is left in the off-gas stream to be burned as fuel.

Large-scale SGL recovery would require new infrastructure, particularly to access off-gas from the Fort McMurray region and deliver it to the Heartland region near Edmonton, Alberta. For example, additional extraction and $C_2/C_{2=}$ fractionation capacity as well as separate product pipelines would be required. On the other hand, given the outlook for SCO production by 2012, it is expected that upgrader capacity will increase to the point where upgraders may produce up to 600 MMcfd of off-gas. Consequently by 2010 to 2012, off-gas volumes could reach a level where upgraders should be considering the value-added synergies of recovering available SGL. Cokers will reach this point faster than hydrogen addition upgraders, as the coking process produces greater volumes of SGL.

Merchant upgraders may be more open to taking advantage of SGL recovery opportunities compared with integrated oil companies. For example, BA Energy Inc. (BA) is in the process of constructing a merchant upgrader in Fort Saskatchewan, Alberta. Phase 1 of its project will have a capacity to upgrade 12 200 m^3/d (77 Mb/d) of bitumen blend; upon completion of Phase 3, the capacity would triple to about 39 700 m^3/d (250 Mb/d). BA is also evaluating access to long-term off-gas extraction and fractionation service (to produce $C_2/C_{2=}$ and C_{3+} cuts) from a proposed third-party facility on a fee-for-service basis. Both prospective partners would be located in the Heartland region and would have access to various nearby infrastructure.

8.2.2 Propane/Propylene ($C_3/C_{3=}$)

About 682 000 tonnes (1.5 billion pounds) per year of propylene has been identified in Alberta as available from upgrader/refinery off-gas and ethylene cracker processes—enough feedstock to supply a worldscale poly-propylene plant. Propylene is the main driver behind the Redwater $C_3/C_{3=}$ fractionation facility as propylene is a high value component. These facilities commenced operation in 2002 with the expectation of accessing propylene from several sources in Alberta. The Redwater splitter is currently not fully utilized and could accommodate additional olefinic feedstocks. Presently, olefinic C_{3+} mix from Suncor's upgrader is the only feed to the $C_3/C_{3=}$ splitter.

Over the past few years many factors have changed such as improved economic growth leading to increased propylene and propylene derivative product prices. With North American propylene demand growth increasing at a rate of three to four percent per annum and a future shortfall expected, there is an opportunity to utilize propylene in Alberta. The question of how to capture this opportunity remains. With this in mind, the Alberta Government, along with other industry parties, is presently examining the cost competitiveness of a propylene derivative plant in Alberta.

8.3 Outlook: Issues and Uncertainties

While not currently feasible, there may be an opportunity to recover ethane (up to about 9 500 m^3/d or 60 Mb/d, depending on upgrader configuration) and other SGL from off-gas within the 2010 to 2012 time frame. There are several uncertainties that could impact the development of this supply. These include:

- The building of SGL infrastructure will compete with oil sands infrastructure requirements.
- A capital incentive or credit against royalty payments on enhanced ethane production being considered by the Alberta Government, if approved, may apply to incremental, conventional gas liquids sources only. That is, it may not apply to SGL available from upgrader or refinery off-gas. This would suggest that incremental ethane derived from taking a deeper cut from conventional natural gas would be the most likely next tranche of ethane supply. However, with a similar royalty credit, ethane from bitumen upgrader off-gas may be cost competitive with incremental conventional ethane.
- In order for the Alberta ethylene sector to expand, substantial additional, secure long-term and cost-competitive feedstock supply will be required.
- The natural gas make-up requirement (i.e., to replace removed gas liquids content) currently used by the midstream sector has been a deterrent to ethane production from off-gas. The natural gas replacement requirement is, in effect, tying SGL recovery costs to natural gas. Consequently, a replacement requirement of somewhat less than 100 percent of natural gas content, a percent of proceeds arrangement, or tying the replacement of heat content cost to a lower-valued bitumen product could be suitable alternatives.
- Aggregation of all propylene identified as available in Alberta would be capital intensive, requiring construction of new infrastructure and may require a financial incentive.

In conclusion, some questions need to be addressed. If SCO production reaches the level projected in this report, will associated off-gas volumes reach a point where recovering SGL would be economic? On the other hand, is there an alternative use for off-gas in addition to process fuel?

Glossary

Apportionment	The method of allocating the difference between the total nominated volume and the available pipeline operating capacity, where the latter is smaller.
Aquifer	An underground geological formation, or group of formations, that contain water.
Aromatics	A term referring to compounds containing one or more six-carbon rings, with alternating (or resonating) carbon-hydrogen double bonds. Benzene, toluene and xylene are examples of common aromatic hydrocarbons.
Barrel	One barrel is approximately equal to 0.159 cubic metres or 158.99 litres or approximately 35 Imperial gallons.
Bitumen or crude bitumen	A highly viscous mixture, mainly of hydrocarbons heavier than pentanes. In its natural state, it is not usually recoverable at a commercial rate through a well because it is too thick to flow.
Blended bitumen	Bitumen to which light oil fractions have been added in order to reduce its viscosity and density to meet pipeline specifications.
Brackish water	Water with a total dissolved solids concentration greater than 4,000 milligrams per litre. It is not suitable for consumption or agricultural use. Also known as saline water.
C_2	Ethane.
$C_{2=}$	Ethylene.
$C_2/\ C_{2=}$	Ethane/Ethylene Stream.
C_{2+}	Ethane plus refers to a mixture of natural gas liquids consisting of ethane and heavier hydrocarbons.
C_3	Propane.
C_{3+}	Propane plus refers to a mixture of natural gas liquids consisting of propane and heavier hydrocarbons.
$C_3/\ C_{3=}$	Propane/propylene stream.

Cogeneration	A facility that produces process heat and electricity. Also known as combined heat and power (CHP) facility.
CO_2	Carbon dioxide.
Coke	A solid black carbon residue remaining after valuable hydrocarbons are extracted from bitumen.
Coker	A vessel in which bitumen is cracked into lighter fractions and withdrawn to start the conversion of bitumen into upgraded crude oil. The lighter fractions, primarily naphtha and gas oils, become the main ingredients of the final blend.
Condensate	A mixture comprised mainly of pentanes and heavier hydrocarbons recovered as a liquid from field separators, scrubbers or other gathering facilities or at the inlet of a natural gas processing plant before the gas is processed.
Conventional crude oil	Crude oil, which at a particular point in time, can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil.
Cracking	The process of breaking down larger, heavier more complex hydrocarbon molecules into smaller, lighter molecules.
Cyclic Steam Stimulation (CSS)	A method of recovering bitumen from a reservoir using steam injection to heat the reservoir to reduce the viscosity of the oil and provide pressure support for production. Oil production occurs in cycles, each of which begins with a period of steam injection followed by the same well being used as a producer.
Deep-cut plant	Refers to a plant that extracts ethane and heavier hydrocarbons from natural gas streams.
DilBit	Bitumen that has been reduced in viscosity through addition of a diluent (or solvent) such as condensate or naphtha.
Diluent	Any lighter hydrocarbon, usually pentanes plus, added to heavy crude oil or bitumen in order to facilitate its transport on crude oil pipelines.
Distillate	Fraction of crude oil; a term generally used for naphthas, diesel, kerosene and fuel oils.
DilSynBit	A blend of bitumen, condensate and synthetic crude oil that has similar properties to medium sour crude.
Ecosystem	A biological community of interacting organisms and their physical environment.

Ethane	The simplest straight-chain hydrocarbon structure with two carbon atoms.
Extraction	A process unique to the oil sands industry, in which bitumen is separated from the oil sands.
Groundwater	Water beneath the earth's surface, often between saturated soil and rock, that supplies wells and springs.
Heat rate	The amount of input energy used to generate electricity, commonly expressed in gigajoules per gigawatt hour (GJ/GW.h).
Heavy crude oil	Generally, a crude oil having a density greater than 900 kg/m^3.
Horizontal well	A well that deviates from the vertical and is drilled horizontally along the pay zone. In a horizontal well, the horizontal extension is that part of the wellbore beyond the point where it first deviates by 80 degrees or more from vertical.
Hydrocarbons	Organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products. Hydrocarbons may be liquid, gaseous or solid.
Hydrocracking	The breaking of hydrocarbon chains into smaller molecules in the presence of hydrogen and a catalyst such as platinum. The end result is a high quality gasoline and other light hydrocarbons.
Hydrotreating	A process used to saturate olefins and improve hydrocarbon stream quality by removing unwanted materials such as nitrogen, sulphur, and metals utilizing a selected catalyst in a hydrogen environment.
Integrated mining plant	A combined mining and upgrading operation where oil sands are mined from open pits. The bitumen is then separated from the sand and upgraded by a refining process.
In situ recovery	The process of recovering crude bitumen from oil sands other than by surface mining.
Light crude oil	Generally, crude oil having a density less than 900 kg/m^3. Also a collective term used to refer to conventional light crude oil, upgraded heavy crude oil and pentanes plus.
Lloyminster Blend	LLB is a heavy crude oil, produced in Canada, which is the benchmark grade of crude oil for Canadian price quotations.
Merchant upgrader	Processing facilities that are linked not to any specific extraction project, but designed to accept raw bitumen on a contract basis from producers.

Natural gas liquids	Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes and pentanes plus.
Off-gas	A mixture of hydrogen and light hydrocarbon gases (including paraffins ethane, propane and butanes; and olefins ethylene, propylene and butylenes) produced when bitumen is upgraded to synthetic crude oil.
Oil sands	Sand and other rock material that contains bitumen. Each particle of oil sand is coated with a layer of water and a thin film of bitumen.
Olefins	Refers to any open-chain hydrocarbon such as ethylene, propylene and butylenes, having the general formula C_nH_{2n} with a carbon-to-carbon double bond.
PADD	Petroleum Administration for Defense District that defines a market area for crude oil in the U.S.
Paraffin	A straight-chain hydrocarbon without double bonds; also called an alkane.
Pentanes plus	A mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil.
Real price	The price of a commodity after adjusting for inflation. In this report most real energy prices are expressed in 2005 dollars.
Reclamation	Returning disturbed land to a stable, biologically-productive state.
Recovery - Primary	The extraction of crude oil from reservoirs utilizing the natural energy available in the reservoirs and pumping techniques.
Remedial action scheme	A system to prevent a cascading blackout of a power system by taking generation out of service if part of the transmission system fails.
Reserves - Established	The sum of the proven reserves and half probable reserves.
Reserves - Initial established	Established reserves prior to deduction of any production.
Reserves - Proven	Reserves recoverable under current technology and present and anticipated economic conditions, specifically demonstrated by drilling, testing or production.
Reserves - Remaining	Initial reserves less cumulative production at a given time.
Reservoir	A reservoir (or pool) is a porous and permeable underground rock formation containing a natural accumulation of crude oil that is confined by impermeable rock or water barriers.

Resources - Recoverable	That portion of the ultimate resources potential recoverable under expected economic and technical conditions.
SAGD	Steam Assisted Gravity Drainage is a steam stimulation technique using horizontal wells in which the bitumen drains, by gravity, into the producing wellbore. In contrast to cyclic steam stimulation, steam injection and oil production are continuous and simultaneous.
Straddle plant	A reprocessing plant located on a gas pipeline. It extracts natural gas liquids from previously processed gas before the gas leaves or is consumed within the province.
Supply cost	Expresses all costs associated with resource exploitation as an average cost per unit of production over the project life. It includes capital costs associated with exploration, development, production, operating costs, taxes, royalties and producer rate of return.
Surface water	Lakes and rivers.
SynBit	A blend of bitumen and synthetic crude oil that has similar properties to medium sour crude.
Synthetic gas liquids	Refers to the liquids (ethane, ethylene and propylene in particular) produced from upgrading bitumen to synthetic crude oil.
Synthetic crude oil	Synthetic crude oil is a mixture of hydrocarbons generally similar to light sweet crude oil, derived by upgrading crude bitumen or heavy crude oil.
Unconventional crude oil	Crude oil that is not classified as conventional crude oil (e.g., bitumen).
Upgraded crude oil	Generally refers to crude bitumen and heavy crude oil that have undergone some degree of upgrading, but is commonly synonymous with synthetic crude oil.
Upgrading	The process of converting bitumen or heavy crude oil into a higher quality crude oil either by the removal of carbon (coking) or the addition of hydrogen (hydroprocessing).
VAPEX™	Vaporized Extraction is a process similar to SAGD but using a vaporized hydrocarbon solvent, rather than steam, to reduce the viscosity of crude oil in the reservoir.
West Texas Intermediate	WTI is a light sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.

ECONOMIC AND MARKET ASSUMPTIONS FOR SUPPLY COST MODELS

TABLE A1.1

Economic Assumptions

Rate of Return	10 percent real, 12 percent nominal
Royalty	Alberta oil sands regime
Federal Taxes	Current oil sands terms
Provincial Taxes	Current Alberta rates
Inflation – constant (percent)	2.0
Exchange Rate US$/C$	0.85

TABLE A1.2

Market Pricing Assumptions

Natural gas NYMEX (US$ per MMBtu)	7.50
Natural gas AECO (C$/GJ)	8.25
NYMEX – AECO Natural Gas (US$ per MMbtu)	0.50
WTI @ Cushing, OK (US$ per barrel)	50.00
Condensate premium over MSW @ Edmonton (percent)	10.00
MSW @ Edmonton – Syncrude @ Edmonton (US$ per barrel)	0.00
MSW @ Edmonton – Lloydminster Blend @ Hardisty (US$ per barrel)	15.00
Heavy crude transportation differential to Chicago: Hardisty vs. Cushing (US$ per barrel)	1.25
Light crude transportation differential to Chicago: Edmonton vs. Cushing (US$ per barrel)	1.00

ASSUMPTIONS FOR ATHABASCA SAGD MODEL

TABLE A2.1

Project Assumptions: High-Quality SAGD

(costs in per barrel of bitumen produced)	
Steam-to-oil ratio (dry)	2.5
Natural gas consumption (Mcf/b)	1.05
Non-gas cash operating costs[a] (C$ per barrel)	3.50
Reduction in operating costs (percent per year)	0
Required diluent – percent of blend volume	33.3
Project start date	2006
Project end date	2047
Kyoto compliance cost (C$ per barrel)	0.00
Capital expenditures to first oil (millions C$ 2005)	450
Capital expenditures over project life (billions C$ 2005)	2.7
Condensate transportation to Plant (C$ per barrel)	0.80
Bitumen blend transportation differential: Plant vs. Hardisty (C$ per barrel)	1.15

a Other non-gas cash operating costs include purchased power, administration, environmental and other direct costs associated with the operation.

TABLE A2.2

Phase Schedule: High-Quality SAGD

	First Oil	Cumulative Production (m^3/d)	Cumulative Production (b/d)
Phase 1	2009	4 800	30,000
Phase 2	2012	9 600	60,000
Phase 3	2015	14 400	90,000
Phase 4	2018	19 200	120,000

TABLE A2.3

Reservoir Assumptions: High-Quality SAGD

Oil sands area	Athabasca
Oil sands deposit	McMurray
API°	8
Continuous pay thickness (m)	35
Porosity (percent)	35
Effective vertical permeability (Darcies)	5

Assumptions for Athabasca Mining/Extraction and Upgrading Model

TABLE A3.1

Project Assumptions

	Mining Extraction & Upgrading
External natural gas consumption (Mcf/b)	0.75
Non-gas cash operating costs[a] (C$ per barrel)	12.00
Reduction in operating costs (percent per year)	0.00
Kyoto compliance cost (C$ per barrel)	0.00
Capital maintenance cost (C$ per barrel)	1.25
Capital expenditure excluding maintenance capital (billions C$)	10.0
Project start date	2006
Project end date	2050
Transportation differential: Plant vs. Edmonton (C$ per barrel)	0.70

a Other non-gas cash operating costs include purchased power, administration, environmental and other direct costs associated with the operation.

TABLE A3.2

Phase Schedule

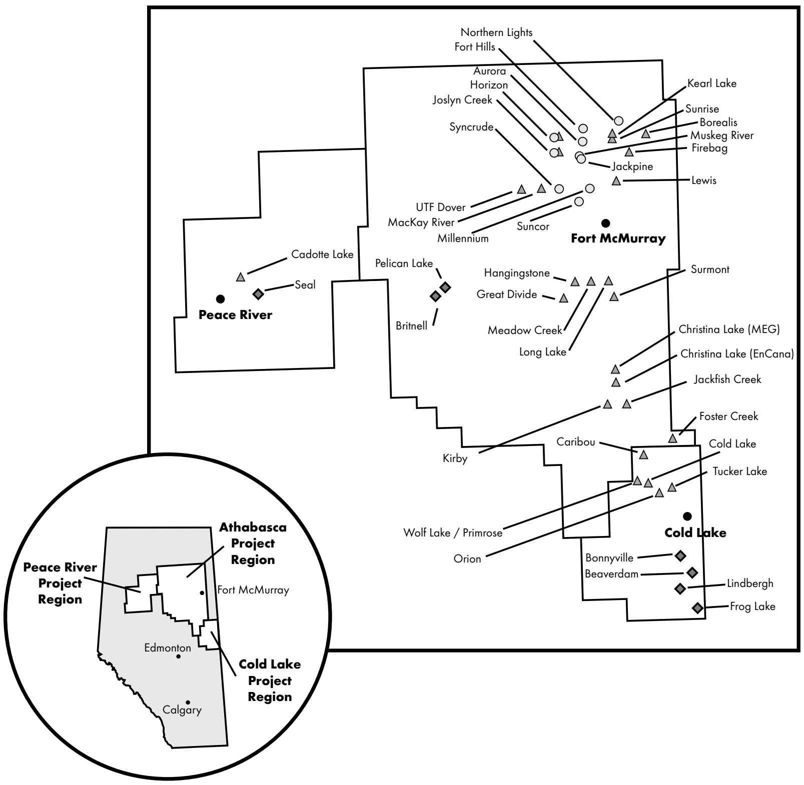
	First Oil	Cumulative Production (m^3/d)	Cumulative Production (b/d)
Phase 1	2010	15 873	100,000
Phase 2	2012	31 746	200,000

TABLE A3.3

Reservoir Assumptions

Oil Sands Area	Athabasca
Oil Sands Deposit	McMurray
API°	8
Bitumen grade – weight percent	11

Oil Sands Projects



LEGEND

In Situ Projects △	***Operator***
Orion	BlackRock Ventures
Kirby	Canadian Natural Resources
Wolf Lake/Primrose	Canadian Natural Resources
Surmont	ConocoPhillips/Total
Great Divide	Connacher Oil and Gas
UTF (Dover)	Devon Energy
Jackfish Creek	Devon Energy
Borealis	EnCana
Christina Lake	EnCana
Foster Creek	EnCana
Caribou	Husky Energy
Sunrise	Husky Energy
Tucker Lake	Husky Energy
Cold Lake	Imperial Oil
Hangingstone	Japan Canada Oil Sands (JACOS)
Christina Lake	MEG
Long Lake	OPTI/Nexen
Lewis	Petro-Canada
MacKay River	Petro-Canada
Meadow Creek	Petro-Canada/Nexen
Cadotte Lake	Shell Canada
Firebag	Suncor Energy
Joslyn Creek	Total E&P Canada

Mining Projects ○	***Operator***
Muskeg River	Albian Sands (Shell/Chevron/Western Oil Sands)
Jackpine Mine	Albian Sands (Shell/Chevron/Western Oil Sands)
Horizon*	Canadian Natural Resources
Kearl Lake	Imperial Oil
Suncor Base Mine	Suncor Energy
Millennium	Suncor Energy
Syncrude Base Mine	Syncrude Joint Venture
Aurora	Syncrude Joint Venture
Northern Lights	Synenco
Fort Hills	Petro-Canada/UTS Energy/Teck Cominco
Joslyn Creek	Total E&P Canada

Major Primary Production Areas ◇

SEAL
Pelican Lake
Lindbergh
Frog Lake
Brintnell
Bonnyville
Beaverdam

* Includes plans for both in situ and mining

Mining/Extraction and Upgrading Projects

Company/Project Name	Project Status	Startup Date	Bitumen Capacity (b/d)	Bitumen Capacity (m^3/d)
Athabasca Oil Sands Project				
Muskeg River Mine				
Existing Facilities	Operating	2002	155,000	24 600
Expansion and Debottleneck	Application	2010	115,000	18 300
Jackpine Mine				
Phase 1A	Approved	2010	100,000	15 900
Phase 1B	Approved	2012	100,000	15 900
Phase 2	Disclosure	2014	100,000	15 900
Scotford Upgrader				
Phase 1	Operating	2003	155,000	24 600
Debottleneck	Application	2007	45,000	7 100
Expansion	Application	2009	90,000	14 300
CNRL				
Horizon Mine & Upgrader				
Phase 1	Construction	2008	135,000	21 400
Phase 2	Approved	2011	45,000	7 100
Phase 3	Approved	2011	90,000	14 300
Phase 4	Announced	2015	145,000	23 000
Phase 5	Announced	2017	162,000	25 700
Primrose Upgrader				
Phase 1	Announced	2012	145,000	23 000
Phase 2	Announced	2015	58,000	9 200
Fort Mackay First Nation				
Fort Mackay Mine				
Phase 1	Announced	TBD	TBD	TBD
Husky				
Lloydminster Upgrader				
Existing Operations	Operating	1992	71,000	11 300
Debottleneck	Construction	2006	12,000	1 900
Expansion	Announced	TBD	67,000	10 600
Imperial/ExxonMobil				
Kearl Mine				
Phase 1	Application	2010	100,000	15 900
Phase 2	Application	2012	100,000	15 900
Phase 3	Application	2018	100,000	15 900

Mining/Extraction and Upgrading Projects (continued)

Company/Project Name	Project Status	Startup Date	Bitumen Capacity	
			(b/d)	(m³/d)
OPTI/Nexen				
Long Lake Upgrader				
Phase 1	Construction	2007	72,000	11 400
Phase 2 (South)	Approved	2011	72,000	11 400
Phase 3	Announced	2013	72,000	11 400
Phase 4	Announced	2015	72,000	11 400
Petro-Canada/UTS/Teck Cominco				
Fort Hills Mine				
Phase 1/2	Approved	2011	100,000	15 900
Phase 3/4	Approved	2014	90,000	14 300
Fort Hills Upgrader				
Phase 1/2	Announced	2011	100,000	15 900
Phase 3/4	Announced	2014	90,000	14 300
Suncor				
Steepbank & Millennium Mine				
Steepbank & N.Steepbank Extension	Operating	1967	276,000	43 800
Steepbank Debottleneck	Construction	2006	25,000	4 000
Millennium Debottleneck	Construction	2008	23,000	3 700
Tar Island Upgrader				
Base U1 and U2	Operating	1967	281,000	44 600
Millennium Vacuum Unit	Operating	2005	43,000	6 800
Millennium Coker Unit	Construction	2008	116,000	18 400
Voyageur Upgrader				
Phase 1	Application	2010	156,000	24 800
Phase 2	Application	2012	78,000	12 400
Syncrude				
Mildred Lake & Aurora Mining and Upgraders				
Existing Facilities	Operating	1978	290,700	46 100
Stage 3 Expansion	Construction	2006	116,300	18 500
Stage 3 Debottleneck	Announced	2011	46,500	7 400
Stage 4 Expansion	Announced	2015	139,500	22 100
Synenco				
Northern Lights Mine				
Phase 1	Disclosure	2009	50,000	7 900
Phase 2	Disclosure	2011	50,000	7 900
Northern Lights Upgrader				
Phase 1	Disclosure	2010	50,000	7 900
Phase 2	Disclosure	2012	50,000	7 900

Mining/Extraction and Upgrading Projects (continued)

Company/Project Name			Project Status	Startup Date	Bitumen Capacity (b/d)	(m³/d)
Total E&P (formerly Deer Creek)						
	Joslyn Mine					
		Phase 1 (North)	Application	2010	50,000	7 900
		Phase 2 (North)	Application	2013	50,000	7 900
		Phase 3 (South)	Announced	2016	50,000	7 900
		Phase 4 (South)	Announced	2019	50,000	7 900
	Joslyn/Surmont Upgrader					
		Phase 1	Announced	2010	50,000	7 900
		Phase 2	Announced	2013	50,000	7 900
Value Creation						
	North Joslyn Upgrader					
		Phase 1	Announced		40,000	6 300

Merchant Upgraders

Company/Project Name			Project Status	Startup Date	Bitumen Capacity (b/d)	(m³/d)
BA Energy						
	Heartland Upgrader					
		Phase 1	Construction	2008	54,400	8 600
		Phase 2	Approved	2010	54,400	8 600
		Phase 3	Approved	2012	54,400	8 600
BA Energy North West Upgrading						
	North West Upgrade					
		Phase 1	Application	2010	50,000	7 900
		Phase 2	Application	2013	54,400	7 900
		Phase 3	Application	2016	54,400	7 900
Peace River Oil Upgrading						
	Bluesky Upgrader					
		Phase 1	Announced	2010	25,000	4 000
		Phase 2	Announced	TBD	25,000	4 000
		Phase 3	Announced	TBD	25,000	4 000
		Phase 4	Announced	TBD	25,000	4 000

In Situ Projects

Athabasca Oil Sands Area In Situ Projects				
Company/Project Name	**Project Status**	**Startup Date**	**Bitumen Capacity**	
			(b/d)	**(m^3/d)**
CNRL				
Birch Mountain				
Phase 1	Announced	2013	30,000	4 800
Phase 2	Announced	2015	30,000	4 800
Gregoire Lake				
Phase 1	Announced	2016	30,000	4 800
Phase 2	Announced	2018	30,000	4 800
Phase 3	Announced	2020	30,000	4 800
Phase 4	Announced	2023	30,000	4 800
Kirby				
Phase 1	Approved	2011	30,000	4 800
Connacher				
Great Divide				
Phase 1	Application	2006	10,000	1 600
ConocoPhillips				
Surmont				
Phase 1	Construction	2006	25,000	4 000
Phase 2	Approved	2008	25,000	4 000
Phase 3	Approved	2011	25,000	4 000
Phase 4	Approved	2014	25,000	4 000
Devon				
Jackfish				
Jackfish 1	Construction	2008	35,000	5 600
Jackfish 2	Disclosure	2010	35,000	5 600
EnCana				
Borealis				
Phase 1	Announced	2010	20,000	3 200
Phase 2	Announced	2011	20,000	3 200
Phase 3	Announced	2012	20,000	3 200
Phase 4	Announced	2013	20,000	3 200
Phase 5	Announced	2014	20,000	3 200

Athabasca Oil Sands Area In Situ Projects (continued)

Company/Project Name			Project Status	Startup Date	Bitumen Capacity	
					(b/d)	(m^3/d)
	Christina Lake					
		Phase 1A	Operating	2002	10,000	1 600
		Phase 1B	Approved	2008	30,000	4 800
		Phase 1C	Approved	2009	30,000	4 800
		Phase 1D	Announced	2010	30,000	4 800
		Unnamed Expansion 1	Announced	2011	30,000	4 800
		Unnamed Expansion 2	Announced	2012	30,000	4 800
		Unnamed Expansion 3	Announced	2013	30,000	4 800
		Unnamed Expansion 4	Announced	2014	30,000	4 800
		Unnamed Expansion 5	Announced	2015	30,000	4 800
	Foster Creek					
		Phase 1A	Operating	2001	24,000	3 800
		Phase 1B - Debottleneck	Operating	2003	6,000	1 000
		Phase 1C - Stage 1	Operating	2005	10,000	1 600
		Phase 1C - Stage 2	Construction	2006	20,000	3 200
		Phase 1D	Announced	2006	20,000	3 200
		Phase 1E	Announced	2007	20,000	3 200
		Unnamed Expansion 1	Announced	2009	25,000	4 000
		Unnamed Expansion 2	Announced	2011	25,000	4 000
Husky						
	Sunrise					
		Phase 1	Approved	2008	50,000	7 900
		Phase 2	Approved	2010	50,000	7 900
		Phase 3	Approved	2012	50,000	7 900
		Phase 4	Approved	2014	50,000	7 900
JACOS						
	Hangingstone					
		Pilot	Operating	2002	10,000	1 600
		Phase 1	Disclosure	2010	25,000	4 000
		Phase 2	Disclosure	2012	25,000	4 000
MEG						
	Christina Lake					
		Pilot	Construction	2007	3,000	500
		Commercial	Application	2008	22,000	3 500

Athabasca Oil Sands Area In Situ Projects (continued)						
Company/Project Name			**Project Status**	**Startup Date**	**Bitumen Capacity**	
					(b/d)	**(m^3/d)**
North American						
	Kai Kos Dehseh					
		Phase 1	Announced	2008	10,000	1 600
		Phase 2	Announced	2010	30,000	4 800
		Phase 3	Announced	2011	40,000	6 300
		Phase 4	Announced	2013	40,000	6 300
		Phase 5	Announced	2015	40,000	6 300
OPTI/Nexen						
	Long Lake					
		Pilot	Operating	2003	2,500	400
		Phase 1	Construction	2006	72,000	11 400
		Phase 2 (South)	Disclosure	2010	72,000	11 400
		Phase 3	Announced	2012	72,000	11 400
		Phase 4	Announced	2014		
Orion						
	Whitesands					
		Pilot	Startup	2006	2,000	300
Petro-Canada						
	Chard					
		Phase 1	Announced	TBD	40,000	6 300
	Dover					
		SAGD Pilot	Operating	2001	1,400	200
		VAPEX Pilot	Operating	2003	100	16
	Lewis					
		Phase 1	Disclosure	TBD	40,000	6 300
		Phase 2	Disclosure	TBD	40,000	6 300
	MacKay River					
		Phase 1	Operating	2002	33,000	5 200
		Phase 2	Application	2009	40,000	6 300
	Meadow Creek					
		Phase 1	Approved	TBD	40,000	6 300
		Phase 2	Approved	TBD		
	Lewis					
		Phase 1	Disclosure	TBD	40,000	6 300
		Phase 2	Disclosure	TBD	40,000	6 300

Athabasca Oil Sands Area In Situ Projects (continued)

Company/Project Name			Project Status	Startup Date	Bitumen Capacity	
					(b/d)	(m^3/d)
Suncor						
	Firebag					
		Phase 1	Operating	2004	33,000	5 200
		Phase 2	Operating	2006	35,000	5 600
		Cogeneration and Expansion	Construction	2009	25,000	4 000
		Phase 3	Approved	2008	35,000	5 600
		Phase 4	Approved	2009	35,000	5 600
		Phase 5	Announced	2012	50,000	7 900
		Phase 6	Announced	2013	50,000	7 900
		Phase 7	Announced	2014	50,000	7 900
		Phase 8	Announced	2015	63,000	10 000
Total E&P (Deer Creek)						
	Joslyn					
		Phase 1	Operating	2004	2,000	300
		Phase 2	Construction	2006	10,000	1 600
		Phase 3a	Disclosure	2009	15,000	2 400
		Phase 3b	Disclosure	2011	15,000	2 400
Value Creation						
	Halfway Creek					
		Phase 1	Announced	2009	10,000	1 600
	North Joslyn					
		Phase 1	Announced	TBD	40,000	6 300

Cold Lake Oil Sands Area In Situ Projects

Company/Project Name			Project Status	Startup Date	Bitumen Capacity	
					(b/d)	(m^3/d)
BlackRock						
	Orion (Hilda Lake)					
		Pilot	Operating	1997	500	100
		Phase 1	Approved	2007	10,000	1 600
		Phase 2	Approved	2009	10,000	1 600
CNRL						
	Primrose					
		Primrose South	Operating	1985	50,000	7 900
		Primrose North	Construction	2006	30,000	4 800
		Primrose East	Application	2009	30,000	4 800

Cold Lake Oil Sands Area In Situ Projects (continued)

Company/Project Name			Project Status	Startup Date	Bitumen Capacity (b/d)	Bitumen Capacity (m^3/d)
Husky						
	Tucker Lake					
		Phase 1	Construction	2006	30,000	4 800
Imperial Oil						
	Cold Lake					
		Phases 1-10: Leming, Maskwa, Mahikan	Operating	1985	110,000	17 500
		Phases 11-13: Mahkeses	Operating	2003	30,000	4 800
		Phases 14-16: Nabiye, Mahikan North	Construction	2006	30,000	4 800

Peace River In Situ Projects

Company/Project Name			Project Status	Startup Date	Bitumen Capacity (b/d)	Bitumen Capacity (m^3/d)
Shell						
	Cadotte Lake					
		Pilot	Operating	1979	1,000	200
		Phase 1	Operating	1986	11,000	1 700
	Carmon Creek					
		Phase 1	Disclosure	2009	18,000	2 900
		Phase 1 Expansion	Announced	2012	35,000	5 600
		Phase 2	Announced	2015	35,000	5 600

Source: Strategy West Inc., Alberta Economic Development, NEB

Conversion Factors and Energy Contents

Abbreviation Table

Prefixes		Equivalent
K	kilo	10^3
M	mega	10^6
G	giga	10^9
T	tera	10^{12}
P	peta	10^{15}
E	exa	10^{18}

Imperial/Metric Conversion Table

Physical Units		Equivalent
m	metre	3.28 feet
m^3	cubic metres	6.3 barrels (oil, LPG)
		35.3 cubic feet (gas)
L	litre	0.22 imperial gallon
b	barrel (oil, LPG)	0.159 m^3

Energy Content Table

Energy Measures		Energy Content
GJ	gigajoules	0.95 million Btu

Electricity		Energy Content
MW	megawatt	
GW.h	gigawatt hour	3600 GJ
TW.h	terawatt hour	3.6 PJ

Natural Gas		Energy Content
MMBtu	million British thermal units	1.05 GJ
Mcf	thousand cubic feet	1.05 GJ
Bcf	billion cubic feet	1.05 PJ

Energy Content Table

Natural Gas Liquids		Energy Content
m^3	Ethane	18.36 GJ
m^3	Propane	25.53 GJ
m^3	Butanes	28.62 GJ

Crude Oil		Energy Content
m^3	Light	38.51 GJ
m^3	Heavy	40.90 GJ
m^3	Pentanes Plus	35.17 GJ

End Notes

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iv Communications with Alberta Environment and NEB. March 9, 2006. This includes allocations for the CNRL's Horizon project and the Shell Jackpine project.

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viii Pembina Institute. *Oil Sands Fever - The Environmental Implications of Canada's Oil Sands Rush*. November 2005. p. 35.

ix Pembina Institute. *Oil Sands Fever - The Environmental Implications of Canada's Oil Sands Rush*. November 2005. p. 33.

x The Pembina Institute's created four scenarios to project future GHG emission growth. The second best scenario for GHG emission projections is used. Source: Pembina Institute. *Oil Sands Fever - The Environmental Implications of Canada's Oil Sands Rush*. November 2005. p. 20.

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xii Government of Canada, *Moving Forward on Climate Change – A Plan for Honouring our Kyoto Commitment* (2005). p. 5. Available at: http://www.climatechange.gc.ca/kyoto_commitments.

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xviii Alberta Learning Minister, Federal Minister of Human Resources and Skills Development Canada, Minister of Citizenship and Immigration Canada, "*Memorandum of Understanding for the Entry of Temporary Foreign Workers for Projects in the Alberta Oil Sands*".

xix Athabasca Regional Issues Working Group, Fact Sheet, June 2005.

xx Athabasca Regional Issues Working Group, Fact Sheet, June 2005.

xxi Nichols Applied Management. "Sustainable Community Indicators Summary Report". Revised Version, January 2006.

xxii Fort McMurray Real Estate Board.

xxiii Edmonton Real Estate Board.

xxiv Calgary Real Estate Board.

xxv Fort McMurray Landlord and Tenants Advisory Board.

xxvi Athabasca Regional Issues Working Group (RIWG) in conjunction with: Regional Municipality of Wood Buffalo, Fort McMurray Public Schools, Fort McMurray Catholic Board of Education, Northland School Division, Keyano College and Northern Lights Health Region. *Wood Buffalo Business Case 2005: A Business Case for Government Investment in the Wood Buffalo Region's Infrastructure*. March 2005.

xxvii This would entail constructing a small dyke in a low-lying area and then pumping water from the Athabasca River during periods of high flow to create a stockpile of water. This stockpile could then be re-released during periods of low flow to increase river flows and allow oil sands mine operations to continue water withdrawals. Source: Golder Associates. *Water supply security for oil sands mines by upstream offsite storage*. http://www.conrad.ab.ca/seminars. water_usage/Water_supply securityfor_oil_sands_mines_Sawatsky.pdf.

xxviii AESO.

xxix Power attributes refers to the environmental and social attributes associated with the way the electricity is generated.

xxx Syngas, or synthesis gas, is a mixture of hydrogen and carbon monoxide that can be produced from a number of sources, including coal, or more commonly for the oil sands, heavy bitumen or asphaltenes produced in the upgrading process.