Canadian Energy Research Institute

Green Bitumen: The Role of Nuclear, Gasification, and CCS in Alberta's Oil Sands

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Study No. 119, Part II - Oil Sands Supply Cost and Production
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PART II – OIL SANDS COST AND PRODUCTION

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CHAPTER 1
INTRODUCTION

This report—Part II of a five-part study—updates the Canadian Energy Research Institute's (CERI's) Oil Sands Supply Outlook released in October 2007. Additional information and projections for oil sands emissions are also provided.

Part III will introduce a selection of alternative technologies that could replace part, or all, of the natural gas requirements used by the oil sands. Only technologies that are commercially available have been considered for the analysis in Part III. Part V will introduce technologies that could become commercial in the future, in addition to technologies where there is currently insufficient public information to produce a reasonable supply cost estimate. Part IV will update the supply costs in Parts II and III, using different economic assumptions, specifically as it pertains to carbon compliance costs. This will enable us to produce a set of compliance costs that could induce technologies shifts away from natural gas to lower greenhouse gas emitting fuel sources.

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CHAPTER 2
OIL SANDS DEVELOPMENT (2007 TO 2030)

The oil sands industry is one of the most energy intensive industries in Alberta. The cost of fuels, particularly natural gas used in oil sands operations, account for a significant portion of the total operating costs. In response to higher and more volatile natural gas and electricity prices, the oil sands industry continues to seek options for more efficient uses of energy.

In this Chapter, we review quantitatively and qualitatively the scale of oil sands operations and their energy needs. A fundamental understanding of the site energy needs, energy sources and energy prices provides a basic requirement for assessing the potential for supply cost and emission reductions–specifically greenhouse gas (GHG)–through the use of alternative fuels.

For the purpose of this analysis, the following bitumen extraction methods shall be used to assist with the formulation of a CERI Reference Case for each method:

- In Situ
  - Cyclic Steam Stimulation (CSS)
  - Steam-Assisted Gravity Drainage Stand-alone (SAGD)
- Mining, Extraction, and Upgrading
  - Mining and Extraction Project (Stand-alone)
  - Mining and Extraction Project with Integrated Upgrader
  - Merchant Upgrader (Stand-alone)

The Reference Cases will be drawn upon as part of the Alternative Fuel Analysis in Part III and IV.

2.1 Oil Sands Energy Requirements

In 2004, CERI published a comprehensive assessment of the oil sands, from the perspective of production and supply costs, the “2004 Study”.[1] The assumptions that underpin the analysis for the in situ projects were based upon an economic and engineering assessment, CERI Study No. 91, published in September 1999. The representative project for each extraction method was refined in 2004 and our mining and upgrading assumptions were developed with cooperation from industry and government. It is these assumptions that CERI still relies upon to develop the representative project that is used to estimate supply costs, production profiles, and gas use associated with oil sands projects. In 2005, the assumptions were further revised as part of CERI’s Cogeneration and Supply Cost study, released in 2006, the “Cogen Study”.[2] The

[1] B. Dunbar, M. Stogran, et. al. “Oil Sands Supply Outlook. Potential Supply and Costs of Crude Bitumen and Synthetic Crude Oil in Canada 2003-2017”, Canadian Energy Research, Study No. 108, March 2004.

[2] Nicole, LeBlanc, David McColl, Luke Chan, Bob Dunbar, George Eynon, Seyed Jazayeri, Vincent Lauernam, Abbas Naini, Melanie Stogran, “Cogeneration Opportunities and Energy Requirements for Canadian Oil Sands Projects – Parts 1 through 5”, Canadian Energy Research Institute Study No. 112, May 2005.

engineering assumptions are continually being re-examined and will likely be updated in the near future as more oil sands related data becomes available; some of the economic assumptions have already been updated based upon a confidential survey of various SAGD oil sands operators (current and planned).

The Cogen Study examined the "integrated" (steam and electric) supply costs associated with the most common thermal in situ production techniques–CSS and SAGD. The steam required to support these projects is heated either through once-through-steam-generators (OTSGs) or in the case of a cogeneration facility, heat-recovery-steam-generators (HRSGs). These facilities require large quantities of natural gas.

A rule-of-thumb commonly used in the industry is that 1.0 Mcf of natural gas is required to produce a barrel of bitumen; however, gas requirements vary depending on the recovery technology, the quality of the reservoir, steam injection and bitumen production cycles, and the efficiency of the steam generation equipment. This rule-of-thumb is appropriate for most in situ recovery operations (i.e., dry steam-oil ratio or SOR of about 2.5), but is too low for less energy efficient operations. A typical SAGD project operates with an average SOR of about 2.5 dry (3.1 wet–wet is based upon 80 percent steam quality, which mean 20 percent of a barrel of steam is water the remaining 80 percent is steam) and would require 1.02 Mcf of natural gas per barrel of bitumen. A typical CSS project operates with an average SOR of about 3.5 wet (2.8 dry) and would require 1.14 Mcf per barrel. However, in situ projects typically use produced associated gas to meet part of the fuel requirements (15 percent is a common value for CSS while 1 percent is common for SAGD). Consequently, a value of 1.0 Mcf per barrel is an appropriate approximation of thermal recovery offsite natural gas requirements.

Table 2.1
Natural Gas Requirements – 30,000 bbl / d Thermal In Situ Projects

Steam-Oil Ratio (SOR)		**Fuel Requirements**	
Wet (barrels per barrel)	Dry (barrels per barrel)	(MMcf/d)	(Mcf per barrel)
2.5	2.0	24.7	0.82
3.0	2.4	29.4	0.98
3.5	2.8	34.1	1.14
4.0	3.2	38.8	1.29
4.5	3.6	43.5	1.45
5.0	4.0	48.2	1.61
5.5	4.4	52.9	1.76
6.0	4.8	57.6	1.92

Table 2.1 is based on the following assumptions for a 30,000-barrel per day (4,800 m^3/d) thermal recovery in situ operation:

- steam generation using once through steam generators
- 175ºC boiler feed-water temperature

- 80 percent steam quality
- 11 MPa (1600 psi) steam pressure
- 3,150 barrel per day (500 m^3/d) internal steam use and losses
- 94 percent OTSG thermal efficiency based on the lower heating value (LHV) of the natural gas

Based upon the Cogen Study, the economic case for cogeneration for in situ projects was not strong. In fact the increased supply cost for cogeneration was less than a dollar per barrel and the study did not conclude whether this added cost sufficiently reduced the risk associated with a projects loss of electricity supply. The Longlake facility currently uses a cogeneration facility; however, this project has on-site upgrading. Canadian Natural Resources (CNRL's) Primrose East Expansion proposes to include cogeneration and will rely upon CSS initially, with SAGD as a "follow-up recovery process".[3] EnCana's Foster Creek and Christina Lake facilities do not use cogeneration. CERI has had discussions about this with various in situ operators, and future operators, and concluded that no decision has been made to use cogeneration. The inclusion of cogeneration in regulatory documents only reflects the intent to consider cogeneration. Using past history as a guide, our projections and supply cost models will exclude cogeneration for future in situ projects, while mining and upgrading projects will rely upon cogeneration. Supply costs estimates will be provided for cogeneration and non-cogeneration Greenfield projects.

Table 2.2 summarizes the natural gas requirements and purchases.

Table 2.2
Oil Sands Natural Gas Requirements and Purchases

	Natural Gas Requirements Mcf/bbl (GJ/bbl)		**Natural Gas Purchases Mcf/bbl (GJ/bbl)**	
	No Cogeneration	**Cogeneration**	**No Cogeneration**	**Cogeneration**
CSS	1.1 (1.2)	2.0 (2.1)	1.0 (1.1)	1.8 (1.9)
SAGD	1.0 (1.1)	1.6 (1.7)	1.0 (1.1)	1.6 (1.7)
Mining & Extraction		0.5 (0.5)		0.5 (0.5)
Upgrading Mcf/bbl of SCO (GJ/bbl of SCO)		0.9 (0.9)		0.6 (0.6)
Integrated Mining & Extraction and Upgrading Mcf/bbl of SCO (GJ/bbl of SCO)		1.0 (1.0)		0.7 (0.7)

SOURCE: Nicole, LeBlanc, David McColl, Luke Chan, Bob Dunbar, George Eynon, Seyed Jazayeri, Vincent Lauerman, Abbas Naini, Melanie Stogran, "Cogeneration Opportunities and Energy Requirements for Canadian Oil Sands Projects – Parts 1 through 5", Canadian Energy Research Institute, Study No. 112, May 2005.

[3] http://www.cnrl.com/assets/north_american_crude_oil_and_liquids/primrose.html, February 26, 2008.

Table 2.3 summarizes the electricity requirements for in situ projects operating at capacity (30,000 bbl/d), mining projects (100,000 bbl/d), upgraders (100,000 bbl SCO/d), and integrated projects (100,000 bbl SCO/d). The requirements are based upon the Cogen Study. Mining projects and upgraders are assumed to meet their steam needs and purchase any electricity that is not met the cogeneration capacity as required.

For a GJh/d equivalent value, divide the MWh/d by 3.6.

Table 2.3
Oil Sands Electricity Requirements and Purchases

		Electricity (MWh / d)			
		Demanded	**Purchased**	**Generated**	**Sold**
CSS	No Cogeneration	300	300	0	0
	Cogeneration	300		4,195	3,895
SAGD	No Cogeneration	300	300	0	0
	Cogeneration	300	0	3,830	3,530
Mining & Extraction	Cogeneration	1,200		1,928	728
Upgrading	Cogeneration	800	448	352	0
Integrated Mining & Extraction and Upgrading Upgrading	Cogeneration	2,180	1,118	1,062	

SOURCE: Nicole, LeBlanc, David McColl, Luke Chan, Bob Dunbar, George Eynon, Seyed Jazayeri, Vincent Lauernam, Abbas Naini, Melanie Stogran, "Cogeneration Opportunities and Energy Requirements for Canadian Oil Sands Projects – Parts 1 through 5", Canadian Energy Research Institute, Study No. 112, May 2005..

2.2 Estimating Capital and Operating Costs for Oil Sands Projects

From early 2000 to 2007, updated capital cost information for some projects—notably CSS—has not been readily available. This is a result of corporate planning policies and also partly due to the changing input cost environment in Alberta. Releasing updated capital cost information each year, could be sending the wrong signal to some investors about a corporations ability to estimate firm costs. Estimating the rate of capital cost inflation over a period of time is a challenge, since no Alberta index for measuring oil sands capital and operating cost inflation exists. In October 2007, CERI performed a confidential survey of SAGD operators for a private client, "Survey". The Survey included currently operating SAGD projects and projects due to commence operation in several years. From this Survey, CERI concluded that capital costs over the period 1999 to 2006 increased by 59 percent, or 8.4 percent per year on average. Over the same period of time, the Nelson-Farrar Refinery Cost Index ("Index") indicates that capital costs for a Refinery increased by 31.4 percent over the same period. Over the same period of time, CNRL's Horizon project saw capital costs rise over 42 percent, including their most recent 2007 estimate[4] capital costs are up 81 percent. The CNRL estimates do include a contingency factor. From 2006 to 2007 the Index indicates a capital cost increase of 6 percent. Anecdotal evidence in Alberta suggests that some of the capital and labour cost increases attributable to oil sands projects are a direct result of local factors. From 1999 to 2006 the Survey based estimate is 27 percent higher than the Index. Since CERI's estimates are derived from local market participants they should adequately represent the Alberta issues.

From this point forward, CERI will use our Survey based estimate as the tool for inflating capital costs when updated capital costs are unavailable from an oil sands operator. Our Survey indicated that operating costs (excluding fuel, taxes and royalties) have also risen over the period by an average of 11.2 percent per year.

2.2.1 Cyclic Steam Stimulation (CSS)

Two major commercial CSS projects are operating in the Cold Lake Area: Imperial Oil's (IOL's) operations at Maskwa/Mahihkan (Phases 1-10) and Mahkeses (Phases 11-13); and Canadian Natural Resource's operations at Primrose and Wolf Lake. Both IOL and CNRL's projects have filed regulatory applications to expand their facilities. The publicly announced capital costs for the expansion of these projects are summarized in Table 2.4.

[4] http://www.cnrl.com/client/whats_new/867/879/0212_horizonupdate.pdf

Table 2.4
Cold Lake CSS Project Capital Costs (2007 dollars)

Project	Capacity (barrels per day)	Capital Cost (Million Canadian dollars)	Capital Cost Dollars Year	Capital Cost (Million 2007 Canadian dollars)	Unit Capital Cost (Million 2007 Canadian dollars per barrel per day)
CNRL Primrose East Expansion	30,000	600[a]	2002	853[b]	28,429
IOL Cold Lake Phases 14 – 16 (Nabiye)	30,000	650[c]	2002	924[d]	30,798

SOURCE:
[a]CNRL, "Public Disclosure Document Proposed Development Plan Primrose East In-Situ Oil Sands Project", September 2004.
[b]CNRL was unable to provide an update of the capital costs for the project.
[c]http://www.limperiale.ca/Canada-English/Files/News/Cold_Lake_backgrounder.pdf, February 28, 2008.
[d]Imperial oil declined comment on the updated capital costs for the project.

Based on information available, the following capital cost estimate was developed for a hypothetical 30,000 barrel per day (4,770 m^3/d) Cold Lake CSS project. The average unit capital cost for the above project is approximately C$29,613 per barrel per day of capacity or $888 million dollars.

Additional wells and well pads would be added early in the life of the project to achieve design production capacity. For the hypothetical 30,000 barrel per day (4,770 m^3/d) Cold Lake CSS project, 15 additional 24-well pads would be added over a 30-year project life, assuming bitumen recovery per well of 600 thousand barrels (95 10^3m^3). Total additional capital would be C$758 million based on an estimated C$46.3 million per well pad, including additional geological and geophysical surveys, stratigraphic test wells, and distribution and gathering lines. Additional sustaining capital of C$4.0 million per year for capital equipment replacements in the central plant facilities would also be required over the project life. This would result in a total capital cost of C$1,647 million over the 30-year project life.

2.2.2 Steam-Assisted Gravity Drainage (SAGD)

Table 2.5 summarizes the publicly available capital costs for recently announced SAGD projects that are used to derive our capital cost estimate for a 30,000 barrel a day.

Table 2.5
Athabasca SAGD Project Capital Costs

Project	Capacity (barrels per day)	Capital Cost (Million Canadian dollars)	Capital Cost Dollars Year	Capital Cost (Million 2007 Canadian dollars)	Unit Capital Cost (Million 2007 Canadian dollars per barrel per day)
DEVON - JackFish 2	35,000	$675[a]	2006	$732	$20,911
NAOSC	10,000	$265[b]	2007	$265	$26,500
Connacher (Great Divide Pod One)	10,000	$260[c]	2007	$260	$26,000
Connacher (Algar)	10,000	$260[d]	2007	$260	$26,000
Laricina Energy	10,000	$300[e]	2007	$300	$30,000

SOURCE:

[a]September 2006 Regulatory Application.

[b]January 29, 2007 Corporate Presentation in New York.

[c]August 2, 2007 Press Release.

[d]August, 2007 Regulatory Application.

[e]http://www.laricinaenergy.com/investor/corporate/rr_sub_05_23_07.pdf.

Based on information available, the average unit capital cost for the above projects is approximately C$25,882 per barrel per day of capacity for a 30,000 barrel per day project.

Additional well pairs would be added over the life of the project to sustain design production capacity. For the hypothetical 30,000 barrel per day (4,770 m^3/d) Athabasca SAGD project, 100 additional well pairs would be added over a 30-year project life, assuming bitumen recovery per well pair of 2.5 million barrels (400 10^3m^3). Total additional capital would be C$552 million assuming C$4.3 million per well pair including additional geological and geophysical surveys, stratigraphic test wells, and distribution and gathering lines. Additional sustaining capital of C$4.0 million per year for capital equipment replacements in the central plant facilities would also be required over the project life. This would result in a total capital cost of C$1.3 billion over the 30-year project life.

2.2.3 Mining and Extraction

Capital cost estimates for mining and extraction projects are summarized in Table 2.6.

Table 2.6
Capital Cost Estimate for Athabasca Mining and Extraction Project

Project	Capacity (barrels per day)	Capital Cost (Million Canadian dollars)	Capital Cost Dollars Year	Capital Cost (Million 2007 Canadian dollars)	Unit Capital Cost (Million 2007 Canadian dollars per barrel per day)
Imperial Kearl	100,000	$6,500	2005	$7,596	$75,957
UTS MINE PHASE 1	140,000	$5,700	2007	$5,700	$40,714
UTS MINE PHASE 2	100,000	$3,900	2007	$3,900	$39,000
Suncor (Voyageur South)	120,000	$4,400	2007	$4,400	$36,667

Capital costs range from C$36,667 to C$75,957 per barrel per day of capacity.[5] An average unit capital cost of C$48,085 per barrel per day of capacity has been used for the base case estimate in this study.

[5] While the two facilities used to derive the average capital cost are associated with the same project, after careful review of the costs for integrated projects and those presented by other sources we are confident that the estimate produced is reasonable for a Greenfield mine.

2.2.4 Standalone Upgrading

Capital cost estimates for upgrading projects are summarized below.

Table 2.7
Capital Cost Estimate for Upgrading Project

Project	Capacity (barrels per day)	Capital Cost (Million Canadian dollars)	Capital Cost Dollars Year	Capital Cost (Million 2007 Canadian dollars)	Unit Capital Cost (Million 2007 Canadian dollars per barrel per day)
NAOSC 1	90,000	$2,700	2006	$2,928	$32,529
NAOSC 2	155,000	$3,875	2006	$4,202	$27,107
NorthWest Phase 1	77,000	$4,200	2007	$4,200	$54,545
BlueSky	50,000	$2,500	2007	$2,500	$50,000
UTS Upgrader 1	140,000	$9,900	2007	$9,900	$70,714
UTS Upgrader 2	100,000	$4,100	2007	$4,100	$41,000
Shell Upgader 2	400,000	$27,000	2007	$27,000	$67,500

Capital costs range from C$27,107 to C$70,714 per barrel per day of capacity and average C$45,983. A unit capital cost of C$45,983 per barrel per day of SCO capacity has been used for the base case estimate in this study (representative of a facility using delayed coking and hydrotreating technology). This unit capital cost is based on detailed cost information for the above projects, excluding the Shell Upgrader 2. It is estimated that a facility employing hydrocracking and hydrotreating technology, similar to the Shell Upgrader 2, would incur higher capital costs. The relatively lower capital costs for the Shell Upgrader likely reflect economies of scale associated with a 400,000 barrel per day upgrader, while the substantially higher capital costs for the UTS Upgrader (Phase) 1 are reflective of costs associated with future expansion plans for Phase 2.

2.2.5 Integrated Mining, Extraction and Upgrading

Capital cost estimates for integrated mining, extraction and upgrading projects are summarized in Table 2.8.

Table 2.8
Capital Cost Estimate for Integrated Mining, Extraction and Upgrading Project

Project	Capacity (barrels per day)	Capital Cost (Million Canadian dollars)	Capital Cost Dollars Year	Capital Cost (Million 2007 Canadian dollars)	Unit Capital Cost (Million 2007 Canadian dollars per barrel per day)
CNRL-Horizon Phase 1	110,000	$8,704	2007	$8,704	$79,127
UTS Phase 1	140,000	$15,600	2007	$15,600	$111,429
UTS Phase 2	100,000	$8,000	2007	$8,000	$80,000
UTS Phase 3	60,000	$7,500	2007	$7,500	$125,000

Capital costs range from C$79,127 to C$125,000 per barrel per day of capacity and average C$98,889. A unit capital cost of C$98,889 per barrel per day of SCO capacity has been used for this study (representative of a facility using delayed coking and hydrotreating technology). The summation of the capital costs for a stand alone mine and upgrader is C$102,552 per barrel per day of SCO capacity; since a mining project produces bitumen, the dollar per barrel is discounted by 0.88 to represent a barrel of SCO from an upgrader with 88 percent conversion.

Based upon information from UTS, approximately 63 percent of the integrated facilities capital costs will be allocated to the mine site (and therefore royalty applicable), the remaining costs will be allocated to the upgrader.

CHAPTER 3
SUPPLY COSTS

3.1 Greenfield Supply Cost Methods

Supply costs for the production of crude bitumen incorporating cogeneration facilities are provided for each of the recovery technologies: CSS, SAGD, mining and extraction, mining, extraction and upgrading, and stand-alone merchant upgrading. It is assumed that a cogeneration unit is included in the capital and operating costs for the recovery technologies. The supply costs for in situ technologies include a no cogeneration case, to reflect future Greenfield projects without cogeneration. The cogeneration facilities are assumed to follow the thermal, or steam, load of the project.

Electricity produced by the cogeneration unit is consumed by the oil sands project, with any excess electricity being sold into the Alberta electricity system at an assumed electricity price. This price is in real terms and fixed over the life of the project. The revenues from the excess electricity generated are accounted for in the calculation of the supply costs.

For the hypothetical 30,000 barrel per day in situ projects—SAGD and CSS—the supply costs are calculated for a cogeneration facility large enough to meet the projects' steam requirements, and a project without cogeneration. Given the large steam requirements and low electricity use (0.010 MWh per produced barrel) there will be excess electricity available for sale to the Alberta grid.

For the mining and extraction case, the supply cost is calculated for a cogeneration facility large enough to satisfy the project's steam requirements—the self-sufficient steam (SSS) case. The SSS case has a cogeneration facility sized to meet all the steam needs. The electricity produced from this facility is greater than the needs of the oil sands project; the excess generation is sold into the Alberta grid, generating revenues. Thus, the SSS case for the mining and extraction technology will have electricity sales. While this scenario is realistic it does increase an operators exposure to risk, through increased natural gas purchases and electricity sales. As more mining and extraction projects move from the application phase into operations, we will be in a better place to judge whether cogeneration will continue for mining projects, or if they will rely on the Alberta system for electricity purchases.

For the purpose of royalty and tax calculations—Appendix B—the cogeneration facilities will be considered inside the royalty fence. In Part III of this study, alternative fuels will be provided on a merchant basis by third party entities, as such you could consider this type of arrangement to be "outside the fence". We believe classifying the projects as inside the fence has a negligible impact on the overall analysis. This conclusion is supported by our previous analysis of cogeneration projects in the oil sands.

In the integrated mining, extraction and upgrading and stand-alone upgrading cases, the supply costs are calculated with a cogeneration facility sized to meet steam requirements, SSS. During the upgrading process, a large amount of waste heat is produced, so the demand for additional steam generation is low, implying a small cogeneration facility is chosen and a small amount of electricity is generated. In these cases, there is the need to purchase additional electricity from the grid. Since and integrated facility can maximize the amount of process heat, the total purchases of natural gas are lower than if the facilities were both stand alone.

Any additional revenues from electricity sales, additional capital, operating and fuel costs, as well as the tax and royalty effects of a cogeneration facility are accounted for in the supply cost calculations.

The bitumen supply cost calculation for each extraction method is described in this section. The supply cost is the constant dollar price needed to recover all capital expenditures, operating costs, royalties, taxes, and earn a specified return on investment. For this study, supply costs are calculated in constant 2007 dollars.

The new Tax Regime introduced by the Canadian Government in the March 19, 2007 budget has been reflected for Greenfield supply costs. The federal budget, as announced, stated that any projects under construction will be grandfathered (in other words, the capital costs will still be accounted for using the previous tax regime in Canada). Since this supply cost model reflects a Greenfield project, no sensitivity analysis has been made as to the impact of the tax regime on projects under construction versus Greenfield projects. Under the new rules, assets acquired after March 19, 2007 will follow a phased out approach to the new Accelerated Capital Cost Allowance, whereby the allowance is gradually phased out, in 10 percent downward increments, from 100 percent in 2010 to 0 percent in 2015.

The supply cost estimates presented here have been calculated using cash flow models that solve for the constant dollar price needed for favourable project economics. The supply cost includes an annual discount rate of 10 percent (real). This is equivalent to an annual return on investment of 12.2 percent (nominal) based on the assumed inflation rate of 2.2 percent per annum. Each individual oil sands company will have their own internal discount rate based upon their risk assessment and financing structure. The 10 percent rate of return is commonly used by investment banks, research institutes, and government departments to reflect a "reasonable" return on the capital invested in the project. Companies may evaluate individual investments using higher or lower discount rates; these would result in higher or lower supply costs than those presented here.

The supply cost is calculated for raw crude bitumen produced in the field. A sensitivity is provided where bitumen is sent to a stand alone upgrader for conversion to a synthetic crude oil with WTI equivalent characteristics. We have assumed that the raw bitumen will be sent to a merchant upgrader in the Athabasca region for conversion to SCO with characteristics comparable to that of WTI.

On July 1, 2007, the Alberta Government enacted their climate change plan, as detailed in Bill 3, "Climate Change and Emissions Management Amendment Act, 2007". This plan involves applying a levy to large final emitters–as defined as those emitting over 100,000 tonnes (T) of carbon dioxide per year–a sum of CDN$15.00/tonne. The levy serves as a contribution to a technology fund, whose purpose is to provide funding for research into emissions reducing technologies. While the province has yet to deploy a trading mechanism/market for carbon, our model incorporates this $15.00/tonne levy for emissions over the 100,000 limit. No assumptions are made to reflect improving technology over time. Part IV will provide an escalating cost of emissions for carbon equivalent CO_2e. The resulting impact on the overall cost for this initial cost of compliance is minimal; however, as the market develops the resulting impact will increase over time. For the purpose of this study, only emissions produced in the combustion of natural gas are included in our emissions compliance cost calculation. The Reference Cases make no assumptions pertaining to improved efficiencies—emissions reductions—per unit of output over the life of the project.

Tables 3.1 to 3.3 present the assumptions used in the calculation of the supply cost.

Table 3.1
Financial Assumptions

Timing		
Base Year	January 1	2007
Start of Construction	January 1	2008
Start of Operations	January 1	2010/2011 Mine
Termination of Operations	December 31	2040/2011 Mine
Year of Currency Inputs		2007
Economic Parameters		
Project Rate of Return (Discount Rate)	%/year, Real	10.0%
Cost Inflation	%/year, Nominal	2.2%
Exchange Rate	US$/C$	0.95
Tax Rates		
Federal Rate	Effective January 1, 2010	19.0%
Federal Surcharge	Eliminated January 1, 2008	0.0%
Alberta Rate	Effective January 1, 2005	10.0%
Alberta Surcharge		0.0%
Royalties		
Minimum Rate		1.0%
Rate after Payout		25.0%
Allowable Return before Payout	Long Term Bond Rate	5.5%
Carbon Dioxide Emissions		
CO_2e Emissions Factor	kg/GJ	51.4
CO_2e Compliance Costs	Real C$ / tonne*	$15.0

* The compliance cost has been assumed as real over the life of a project. A nominal compliance cost would continue to decline over the life of the project, being relatively worthless at the end of the project. Part IV will analyze the impact that various compliance costs could have on oil sands supply costs.

Supply costs are shown on a discounted basis. Discounted results show each factor's contribution to the supply costs when a 10 percent (real) discount rate is applied.

Table 3.2
In Situ Design and Cost Assumptions

		CSS Cogen	CSS	SAGD Cogen	SAGD
Stream Day Capacity	b/d of bitumen	30,000	30,000	30,000	30,000
Capital Expenditures[a]					
Initial Capital	2007 C$million	1,036	888	922	776
Sustaining Capital	2007 C$million/year	26.6	25.3	19.9	18.4
Operating Working Capital	Days payment	45	45	45	45
Abandonment and Reclamation	% of Total Capital	2.0	2.0	2.0	2.0
Operating Costs (Excluding Energy)[b]					
Fixed Operating Costs	2007 C$million/year	85.67	77.73	72.63	65.37
Variable Operating Costs	2007 C$/b	8.6	7.8	5.7	5.0
Energy Purchased (Stream Day)					
Natural Gas Purchased	GJ/d	55,800	31,500	51,600	32,100
AECO-C Gas Price[c]	C$/GJ	Forecasted	Forecasted	Forecasted	Forecasted
Field Premium	C$/GJ	$0.3	$0.3	$0.3	$0.3
Electricity (Stream Day)					
Electricity Price[d]	2007 C$/MWh	$62.7	$62.7	$62.7	$62.7
Electricity Purchased	(MWh/day)	0	300	0	300
Electricity Generated	(MWh/day)	4,195	0	3,830	0
Electricity Sold	(MWh/day)	3,895	0	3,530	0

[a]In order to differentiate in situ, cogeneration projects from their non-cogeneration counterparts, information derived from CERI's Cogen Study is used—inflated from 2004 dollars to 2007 dollars.

[b]Based upon analysis performed for a private client and our survey results, CERI has estimated the in situ operating costs as follows: Fixed operating costs are assumed to be 8.75 percent of total capital costs, while variable operating costs are based upon the costs associated with maintaining wells—assumed to be C$477,000 per well per year.

[c]CERI has forecast natural gas prices, based upon publicly available forecasts by the Sproule, U.S. EIA, ARC Financial and our own internal data. These forecasts (including historic data) are shown in Figure 3.1 out to 2040.

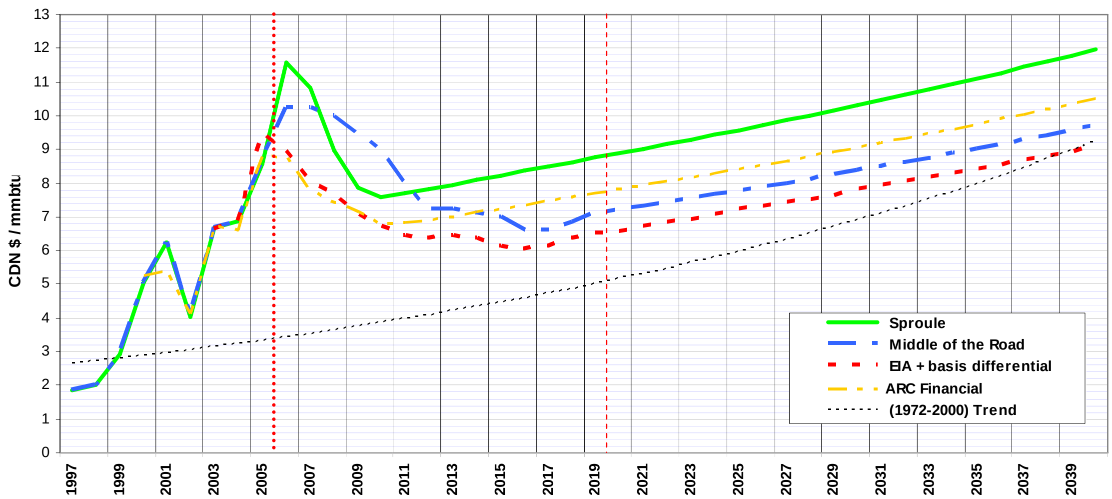
[d]The electricity price has been fixed at $62.7 (real) over the life of the project. We recognize that the forecasted natural gas price and changing environment for carbon compliance costs could drive this price higher in the future, and impact the financial benefits/risks from cogeneration.

Table 3.3
Mining and Extraction, Stand Alone Upgraders, and Integrated Cost Assumptions

		Mining and Extraction	Stand Alone Upgrader	Integrated Mining and Extraction and Upgrader
Stream Day Capacity	b/d of bitumen	100,000	115,000	115,000
Stream Day Capacity	b/d of SCO		100,000	100,000
Capital Expenditures				
Initial Capital	2007 C$ million	4,808	4,598	10,845
Sustaining Capital	2007 C$million/year	24.1	21.1	46.0
Operating Working Capital	Days payment	45	45	45
Abandonment and Reclamation	% of Total Capital	2.0	2.0	2.0
Operating Costs (Excluding Energy)[a]				
Fixed Operating Costs	2007 C$million/year	118.9	124.2	243.1[b]
Variable Operating Costs	2007 C$/b	6.3	3.4	9.7[c]
Energy Purchased (Stream Day)				
Natural Gas Purchased	GJ/d	54,211	81,436	83,213
AECO-C Gas Price[d]	C$/GJ	Forecasted	Forecasted	Forecasted
Field Premium	C$/GJ	$0.3	$0.3	$0.3
Electricity (Stream Day)				
Electricity Price[e]	2007 C$/MWh	$62.7	$62.7	$62.7
Electricity Purchased	(MWh/day)	0	448	1,128
Electricity Generated	(MWh/day)	1,928	352	1,928
Electricity Sold	(MWh/day)	728	0	

[a]Operating costs are based upon information from CERI's 2004 Oil Sands Study and feedback from Industry. Operating costs have been inflated from 2002 dollars to 2007 dollars.
[b]C$118.88 is royalty applicable and associated with the mine.
[c]C$6.26 is royalty applicable and associated with the mine.
[d]CERI has forecast natural gas prices, based upon publicly available forecasts by the Sproule, U.S. EIA, ARC Financial and our own internal data. These forecasts (including historic data) are shown in Figure 3.1 out to 2040.
[e]The electricity price has been fixed at $62.7 (real) over the life of the project. We recognize that the forecasted natural gas price and changing environment for carbon compliance costs could drive this price higher in the future, and impact the financial benefits/risks from cogeneration.

Figure 3.1
Natural Gas Price Forecast
(AECO-C)



After careful analysis, CERI has elected to use the "middle of the road" case as the gas price forecast for this study. The values are converted to $/GJ and a $0.30 field premium is added to account for the cost to transport the gas from the AECO-C market hub to the oil sands region.

3.2 Cyclic Steam Stimulation (CSS) Supply Cost (CSS Supply Cost Reference Case)

Table 3.4
Bitumen Supply Cost at Plant Gate
30,000 barrel per day Cold Lake CSS Project

Supply Cost (Real Canadian dollars per barrel of bitumen, 2007)	Cogeneration	No Cogeneration
Return on Investment	Included	Included
Fixed Capital	14.02	12.57
Operating Working Capital	0.25	0.22
Fuel	8.96	5.06
Other Operating Costs	15.53	14.80
Abandonment Costs	0.01	0.01
Royalties	2.06	1.81
Income Taxes	2.01	1.74
Emissions Compliance Costs	1.25	0.65
Electricity Sales	8.14	0.00
Total Supply Cost	**35.95**	**36.87**

The largest component of the CSS project's supply cost is the "Other Operating Costs" category. This category includes:

- electricity purchases—but excludes any benefits from electricity sales;
- general and administration costs;
- ongoing maintenance costs for the central plant—assumed to be 8.8 percent of total capital costs;[6]
- in addition to the costs associated with maintaining wells—assumed to be C$477,000 per well per year;
- for cogeneration, there is an additional cost associated with the operation—C$0.70 per barrel for a CSS project.

Emissions compliance costs are calculated based upon the natural gas required for the facility, and not based upon the purchased natural gas. Purchased natural gas is used to calculate the "Fuel" component of the supply cost.

Electricity sales are highly susceptible to changes in the price they receive for their electricity. We have assumed they receive a price of C$62.70/MWh. If the price were reduced to C$20/MWh, electricity sales would fall by C$5.50 per barrel. This would reduce the attractiveness of the cogeneration unit. The total supply cost would be C$41.8 or 15 percent higher, while a CSS project without cogeneration purchasing electricity and the same price would experience a 1 percent drop in their supply cost. For this reason, it is difficult to conclude which option is best.

[6] This is captured as the Fixed Operating Costs, and was derived from the Survey of SAGD operators. While designed to reflect a SAGD project, it is a reasonable proxy for a CSS project.

For the purpose of production forecasts, any new CSS projects are assumed to go ahead without cogeneration.

3.2.1 Price Forecast Sensitivity

Table 3.5
Bitumen Supply Cost at Plant Gate
30,000 barrel per day Cold Lake CSS Project

Supply Cost (Real Canadian dollars per barrel of bitumen, 2007)	Cogeneration	No Cogeneration
Return on Investment	Included	Included
Fixed Capital	14.02	12.57
Operating Working Capital	0.25	0.22
Fuel	9.97	5.63
Other Operating Costs	15.53	14.80
Abandonment Costs	0.01	0.01
Royalties	2.35	1.73
Income Taxes	1.94	1.70
Emissions Compliance Costs	1.25	0.65
Electricity Sales	8.14	0.00
Total Supply Cost	**37.18**	**37.31**

Holding all variables constant, we have used the highest gas price forecast (Sproule) to analyze impacts on projects' supply cost. Since the cogeneration scenario uses relatively more gas than the non-cogeneration scenario, its supply cost rose by 3.4 percent. The no cogeneration supply cost increased by 1.2 percent.

3.3 Steam-Assisted Gravity Drainage (SAGD) Supply Cost (SAGD Supply Cost Reference Case)

Table 3.6
Bitumen Supply Cost at Plant Gate
30,000 barrel per day Athabasca SAGD Project

Supply Cost (Real Canadian dollars per barrel of bitumen, 2007)	Cogeneration	No Cogeneration
Return on Investment	Included	Included
Fixed Capital	11.99	10.24
Operating Working Capital	0.23	0.20
Fuel	10.53	6.55
Other Operating Costs	12.90	12.16
Abandonment Costs	0.02	0.01
Royalties	2.32	1.89
Income Taxes	2.49	2.04
Emissions Compliance Costs	1.25	0.72
Electricity Sales	7.38	0.00
Total Supply Cost	**34.36**	**33.81**

The largest component of a SAGD project's supply cost is the "Other Operating Costs" category. This category includes:

- electricity purchases—but excludes any benefits of electricity sales;
- general and administration costs;
- ongoing maintenance costs for the central plant—assumed to be 8.8 percent of total capital costs;[7]
- in addition to the costs associated with maintaining wells—assumed to be C$477,000 per well per year;
- for cogeneration there is an additional cost associated with the operation—C$0.60 per barrel for a SAGD project.

Emissions compliance costs are calculated based upon the natural gas required for the facility, and not based upon the purchased natural gas. Purchased natural gas is used to calculate the "Fuel" component of the supply cost.

For the purpose of production forecasts, any new SAGD projects are assumed to go ahead without cogeneration.

[7] This is captured as the Fixed Operating Costs, and was derived from the Survey of SAGD operators. While designed to reflect a SAGD project, it is a reasonable proxy for a CSS project.

3.3.1 Price Forecast Sensitivity

Table 3.7
Bitumen Supply Cost at Plant Gate
30,000 barrel per day Athabasca SAGD Project

Supply Cost (Real Canadian dollars per barrel of bitumen, 2007)	Cogeneration	No Cogeneration
Return on Investment	Included	Included
Fixed Capital	11.99	10.24
Operating Working Capital	0.23	0.20
Fuel	11.93	7.42
Other Operating Costs	12.90	12.16
Abandonment Costs	0.02	0.01
Royalties	2.44	2.01
Income Taxes	2.39	1.97
Emissions Compliance Costs	1.25	0.72
Electricity Sales	7.38	0.00
Total Supply Cost	**35.78**	**34.74**

Holding all variables constant, we have used the highest gas price forecast (Sproule) to analyze how the supply cost changes. Since the cogeneration scenario uses relatively more gas than the non-cogeneration scenario, its supply cost rose by 6 percent while the no cogeneration supply cost increased by 3 percent. This result is similar to the CSS sensitivity.

3.4 Mining and Extraction Supply Cost Reference Case

Table 3.8
Bitumen Supply Cost at Plant Gate
100,000 barrel per day Athabasca Mining & Extraction Project

Supply Cost (Real Canadian dollars per barrel of bitumen, 2007)	Cogeneration
Return on Investment	Included
Fixed Capital	16.78
Operating Working Capital	0.32
Fuel	3.05
Other Operating Costs	9.67
Abandonment Costs	0.02
Royalties	3.04
Income Taxes	3.04
Emissions Compliance Costs	0.40
Electricity Sales	0.46
Total Supply Cost	**35.86**

The largest component of a Mining project's supply cost is the Fixed Capital, which takes into account the 10 percent rate of return. The "Other Operating Costs" category includes electricity purchases—but excludes any electricity sales—general and administration costs, ongoing maintenance costs for the central plant. Based upon previous work, the components associated with "Other Operating Costs" as shown in Table 3.3 (Fixed and Variable Operating Costs) have been escalated to reflect today's prices. The other operating costs comprise 27 percent of the total supply costs for the project. This is comparable to previous CERI estimates.

3.4.1 Price Forecast Sensitivity

Table 3.9
Bitumen Supply Cost at Plant Gate
100,000 barrel per day Athabasca Mining & Extraction Project

Supply Cost (Real Canadian dollars per barrel of bitumen, 2007)	Cogeneration
Return on Investment	Included
Fixed Capital	16.78
Operating Working Capital	0.32
Fuel	3.57
Other Operating Costs	9.67
Abandonment Costs	0.02
Royalties	3.02
Income Taxes	3.02
Emissions Compliance Costs	0.40
Electricity Sales	0.46
Total Supply Cost	**36.35**

Holding all variables constant, we have used the highest gas price forecast (Sproule) to analyze how the projects' supply cost changes. Mining operations will experience a 1 percent impact on their supply cost, rising from C$35.90/bbl to $36.40/bbl.

3.5 Stand Alone Upgrader Supply Cost Reference Case

Table 3.10
SCO Supply Cost at Plant Gate
100,000 barrel per day Stand Alone Upgrader Project

Supply Cost (Real Canadian dollars per barrel of SCO, 2007)	Cogeneration
Return on Investment	Included
Fixed Capital	15.87
Operating Working Capital	0.26
Fuel	4.57
Other Operating Costs	7.23
Abandonment Costs	0.01
Royalties	0.00
Income Taxes	3.01
Emissions Compliance Costs	0.89
Electricity Sales	0.00
Total Supply Cost	**31.84**

The total supply cost represented here reflects the costs for upgrading a barrel of bitumen in a stand-alone upgrader. No assumption is made as to the cost of the purchased bitumen.

The largest component of an upgrader's supply cost is the Fixed Capital. The next largest contributor to the supply cost is the "Other Operating Costs" category. This category includes electricity purchases—but excludes any electricity sales—general and administration costs, ongoing maintenance costs for the facility plant. Based upon previous work, the components associated with "Other Operating Costs" as shown in Table 3.3 (Fixed and Variable Operating Costs) have been escalated to reflect today's prices. The other operating costs comprise 23 percent of the total supply costs for the project. This is comparable to previous CERI estimates.

3.5.1 Price Forecast Sensitivity

Table 3.11
SCO Supply Cost at Plant Gate
100,000 barrel per day Stand Alone Upgrader Project

Supply Cost (Real Canadian dollars per barrel of SCO, 2007)	Cogeneration
Return on Investment	Included
Fixed Capital	15.87
Operating Working Capital	0.26
Fuel	5.35
Other Operating Costs	7.23
Abandonment Costs	0.01
Royalties	0.00
Income Taxes	2.99
Emissions Compliance Costs	0.89
Electricity Sales	0.00
Total Supply Cost	**32.60**

Holding all variables constant, we have used the highest gas price forecast (Sproule) to analyze the impact higher gas prices could have on the projects' supply cost. Upgraders will receive a 3 percent impact on their supply cost, rising from C$31.80/bbl to $32.60/bbl of SCO.

3.6 Upgrading SAGD Bitumen Supply Cost Sensitivity

Stand Alone upgraders will require a supply of bitumen. In this analysis we consider a stand alone upgrader purchasing Athabasca quality raw bitumen from a SAGD project. The SAGD project is assumed to not use cogeneration, while the upgrader relies upon cogeneration for some of their electrical needs.

It is assumed the cost to transport bitumen from the field to the upgrader[8] is C$1.00/bbl of raw bitumen.

Table 3.12
SCO Supply Cost at Plant Gate
100,000 barrel per day Upgrader Project: Athabasca Quality Bitumen Sourced from SAGD

Supply Cost (Real Canadian dollars per barrel of SCO, 2007)	
Return on Investment	Included
Feedstock (Bitumen)	40.02
Fixed Capital	15.87
Operating Working Capital	0.26
Fuel	4.57
Other Operating Costs	7.23
Abandonment Costs	0.01
Royalties	0.00
Income Taxes	2.64
Emissions Compliance Costs	0.89
Electricity Sales	0.00
Total Supply Cost	71.84

The total supply cost represented here reflects the costs for upgrading a barrel of bitumen, sourced from our previously estimated supply cost for a SAGD project, and processed in a stand-alone upgrader. Our supply cost model indicates that this equates to C$71.80/bbl as a WTI equivalent. However, SCO typically trades at a C$1.00-2.00/bbl discount to WTI. This would imply that global oil prices (WTI) above C$74.00/bbl (real) should be adequate to support upgraders and SAGD producers, with a 10 percent rate of return being accrued to both, over the life of the project.

[8] Implicit within this assumption is that the upgrader is located near Edmonton, e.g. the “Industrial Heartland” in Alberta.

3.7 Upgrading Mined Bitumen Supply Cost Sensitivity

In this analysis we consider a stand alone upgrader purchasing raw bitumen from a mining project. Both the upgrader and the mine use cogeneration on-site. Electricity sales from the mine are accounted for in the mining and extraction projects supply cost. It is assumed the cost to transport bitumen from the field to the upgrader is C$1.00 /bbl of raw bitumen.

Table 3.13
SCO Supply Cost at Plant Gate
100,000 barrel per day Upgrader Project: Athabasca Quality Bitumen Sourced from Mine

Supply Cost (Real Canadian dollars per barrel of SCO, 2007)	
Return on Investment	Included
Feedstock (Bitumen)	42.38
Fixed Capital	15.87
Operating Working Capital	0.25
Fuel	4.57
Other Operating Costs	7.23
Abandonment Costs	0.01
Royalties	0.00
Income Taxes	2.36
Emissions Compliance Costs	0.89
Electricity Sales	0.00
Total Supply Cost	**73.55**

The total supply cost represented here reflects the costs for upgrading a barrel of bitumen, sourced at our previously estimated supply cost for a Mining project, and processed in a stand-alone upgrader. Our supply cost model indicates that this equates to C$73.60/bbl as a WTI equivalent. However, SCO typically trades at a C$1.00-2.00/bbl discount to WTI. This would imply that global oil prices (WTI) above C$76.00/bbl should be adequate to support upgraders and mine producers, with a 10 percent rate of return being accrued to both.

3.8 Integrated Mining and Extraction and Upgrading Supply Cost Reference Case

Integrated Mining and Extraction and Upgrading projects should receive some economies of scale on construction, maintenance and operating costs, and energy use. However, as has previously been stated the capital cost numbers for our integrated project are 20 percent higher than stand alone projects. We have made no assumption for energy efficiency gains through an integrated facility. Under these assumptions, we would anticipate the supply cost to exceed that of the stand alone projects.

Table 3.14
SCO Supply Cost at Plant Gate
100,000 barrel per day Athabasca Mining & Extraction Project

Supply Cost (Real Canadian dollars per barrel of SCO, 2007)	Cogeneration
Return on Investment	Included
Fixed Capital	37.31
Operating Working Capital	0.67
Fuel	4.67
Other Operating Costs	18.24
Abandonment Costs	0.03
Royalties	4.26
Income Taxes	6.85
Emissions Compliance Costs	0.87
Electricity Sales	0.00
Total Supply Cost	**72.91**

The supply cost model indicated that SCO from an integrated facility will cost C$72.91/bbl. Indicating a support for oil sands production (and SCO production) would be attained with real global oil prices (WTI)–averaging over the life of the project–above C$76.00/bbl, and indicated by Tables 3.12 to 3.14.

3.8.1 Price Forecast Sensitivity

Table 3.15
SCO Supply Cost at Plant Gate
100,000 barrel per day Athabasca Mining & Extraction Project

Supply Cost (Real Canadian dollars per barrel of SCO, 2007)	Cogeneration
Return on Investment	Included
Fixed Capital	37.31
Operating Working Capital	0.67
Fuel	5.47
Other Operating Costs	18.24
Abandonment Costs	0.03
Royalties	4.25
Income Taxes	6.83
Emissions Compliance Costs	0.87
Electricity Sales	0.00
Total Supply Cost	**73.67**

Holding all variables constant, we have used the highest gas price forecast (Sproule) to analyze the impact from higher natural gas prices on the projects' supply cost. Integrated projects will receive a 1 percent impact on their supply cost, rising from C$72.91/bbl to $73.67/bbl of SCO.

CHAPTER 4
PROJECTIONS

The oil sands industries primary drivers of greenhouse gas (GHG) emissions growth over the coming decades will be a direct result of the success of oil sands developers. A robust outlook for oil sands expansions will result in an increased consumption of natural gas, which in turn will result in higher emissions. Under the current environment framework in Alberta and Canada, oil sands producers can increase their emissions, subject to compliance costs-but no emissions limit. Chapter 4 will analyze various scenarios for oil sands development and the associated emissions under the status quo.

The status quo for environmental legislation will not remain. Discussions are already underway that will increase emissions restrictions on oil sands developers and result in cleaner fuels, carbon capture and storage, and other emissions reduction measures coming on-stream. The alternative fuels will be discussed in Part III of this study, while Part IV will examine how changes in emissions compliance costs can act as an incentive for cleaner technologies to come to the forefront and help the oil sands develop, while simultaneously reducing GHG emissions. The result could be a cleaner bitumen–Green Bitumen–being produced from the oil sands.

4.1 Production Profile (projection to 2030)

Projections of bitumen and synthetic crude oil (SCO) production from Canada's oil sands are typically based on the summation of all announced projects, with a wide variety of assumptions pertaining to the projects schedule and delays, technology, and state of development. CERI decides which projects are delayed and the rate at which production comes on stream, based upon our past experience\monitoring the progress of oil sands projects. Given the current high price state of the global oil market and "security of supply" concerns from oil importing countries, continued growth in production from the oil sands industry is likely.

Global energy markets and price expectations are not limiting growth in production from the oil sands, because the global oil demand is at a level that supports further production increases. Industry sources and CERI's own supply cost model indicates that a real WTI equivalent price above C$70 (over a projects production horizon of 30 years) is required in order for oil sands production to be economically viable, under current market and regulatory conditions. The industry's development is primarily determined by other limiting factors such as capital spending, labour supply, market access, market uncertainty, material supply, environment, and regulatory uncertainty.

In this Chapter, we present projections for oil sands production and corresponding capital spending, natural gas and electricity requirements, and estimates for total emissions from the oil sands industry based upon our assumptions. The first is the Unconstrained Projection, which assumes all announced projects will proceed on schedule as planned. The other projections are "Constrained" and comprise two alternative supply projections that take into account the limiting factors mentioned above. CERI's database of oil sands projects is updated to January 4, 2008.

4.1.1 Unconstrained Projection - Supply & Investment Projection

The Unconstrained supply projection assumes that all projects tabulated in Appendix A will meet their announced production volumes on time. This projection provides a picture of where the industry will be in 2030 if all projects proceed as planned.

Production is assumed to achieve full capacity in the second year of operation for mining projects, and the third year of operation for all other projects. Mining projects operate at 63 percent of their planned productive capacity in the first year of operation, and then operate at 100 percent of capacity afterwards. Steam-Assisted Gravity Drainage (SAGD) projects, which account for almost 92 percent of all existing and planned in situ production, are assumed to operate at 19 percent of their capacity in the first year of operation, 92 percent in the second year, and 100 percent afterwards. These profiles match the assumptions used in the supply cost calculations and have been verified as reasonable assumptions by industry. The Cyclic Steam Stimulation (CSS) projects account for the remaining in situ production.

Under the Unconstrained Projection, gross crude bitumen production increases from 1.3 million barrels per day (MBPD) in 2007 to 6.0 MBPD in 2030. This scenario takes into account retirements of some oil sands projects; in all likelihood these facilities will continue to expand production as their recoverable resource base increases.[9] Under this projection, crude bitumen upgraded in Alberta will increase from 929,000 barrels per day (BPD) in 2007 to 4.3 MBPD in 2030, as reflected in Table 4.1. Over the projection period, the percentage of raw bitumen sent to upgraders remains relatively constant, averaging 74 percent. Synthetic crude oil production will increase from 802,000 BPD in 2007 to 4.0 MBPD in 2030. Net bitumen production (not upgraded) will increase from 390,000 BPD in 2007 to 1.6 MBPD in 2030. Total net production (net bitumen plus synthetic crude oil) will increase from 1.2 MBPD in 2007 to 5.6 MBPD in 2030. This is the amount of bitumen that is "marketable" and could be exported through pipelines from Alberta. Year-by-year production numbers are presented in Table 4.1 and Figure 4.1, SCO production is presented in Figure 4.3.

[9] Most of these projects are mining and were constructed during a period where the price of oil was close to WTI US$25.00 per barrel. Since the major expenditure was on fixed capital, these producers are able to capture an increasing piece of economic rent, while producing what was once considered an "uneconomic" resource. As more information comes to light about the extended life of these projects, we will update the project "life" to reflect this. Currently, most projects are slated to last 30 to 40 years, depending upon the information provided in the proponents regulatory documents.

Table 4.1
Production Profiles (thousand barrels per day)
Unconstrained Projection

Year	Gross Bitumen Production	Bitumen Sent to Upgraders	Net Bitumen Production	SCO Production	Total Products to Market
2007	1,300	929	371	802	1,173
2008	1,570	1,209	361	1,059	1,419
2009	1,973	1,460	513	1,282	1,795
2010	2,670	1,952	718	1,728	2,445
2011	3,434	2,441	993	2,159	3,152
2012	4,240	3,258	982	2,905	3,887
2013	4,655	3,736	918	3,353	4,271
2014	5,218	4,001	1,217	3,591	4,808
2015	5,649	4,330	1,319	3,884	5,203
2016	5,892	4,496	1,396	4,031	5,427
2017	6,227	4,729	1,498	4,238	5,736
2018	6,545	4,864	1,681	4,357	6,038
2019	6,449	4,641	1,808	4,174	5,982
2020	6,461	4,678	1,783	4,211	5,994
2021	6,474	4,678	1,796	4,211	6,008
2022	6,464	4,678	1,786	4,211	5,997
2023	6,460	4,678	1,782	4,211	5,993
2024	6,479	4,678	1,801	4,211	6,012
2025	6,476	4,678	1,798	4,211	6,009
2026	6,351	4,613	1,738	4,159	5,896
2027	6,203	4,509	1,693	4,075	5,768
2028	6,068	4,416	1,652	3,999	5,651
2029	5,996	4,366	1,630	3,959	5,589
2030	5,980	4,355	1,625	3,950	5,575
Total Projection Period	**45,710,668**	**33,716,832**	**11,993,837**	**30,283,764**	**42,277,601**

Figure 4.1
Unconstrained Gross Crude Bitumen Production

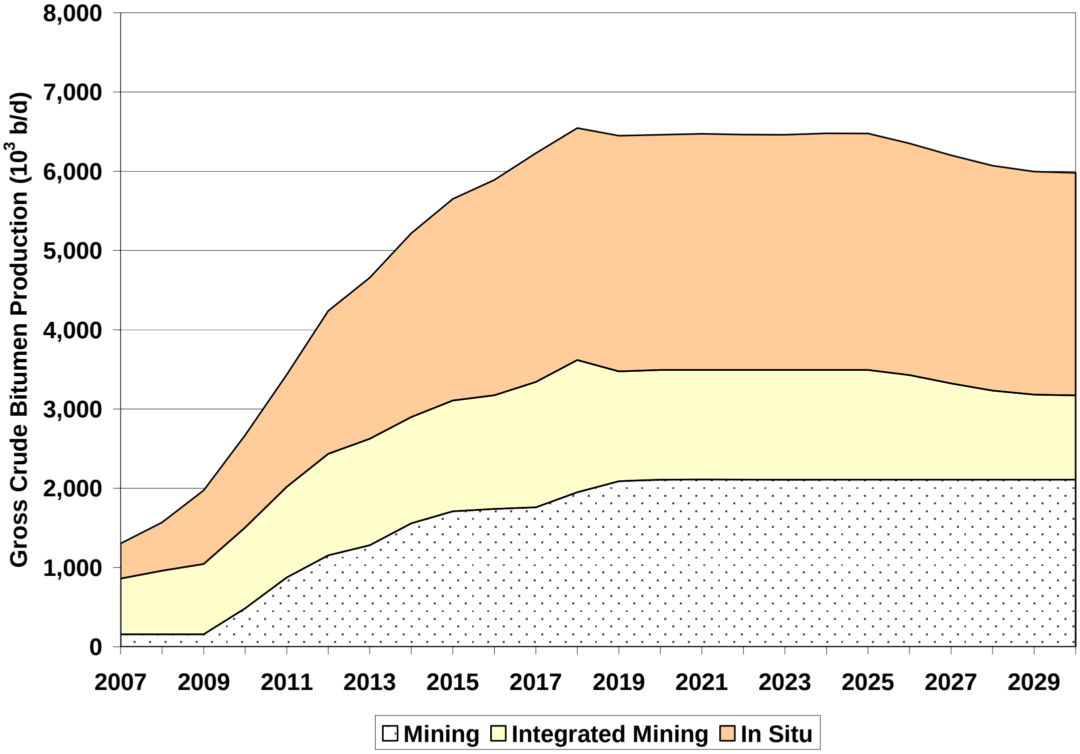


Figure 4.2
Unconstrained Gross Crude Bitumen Production (By Region and Type)

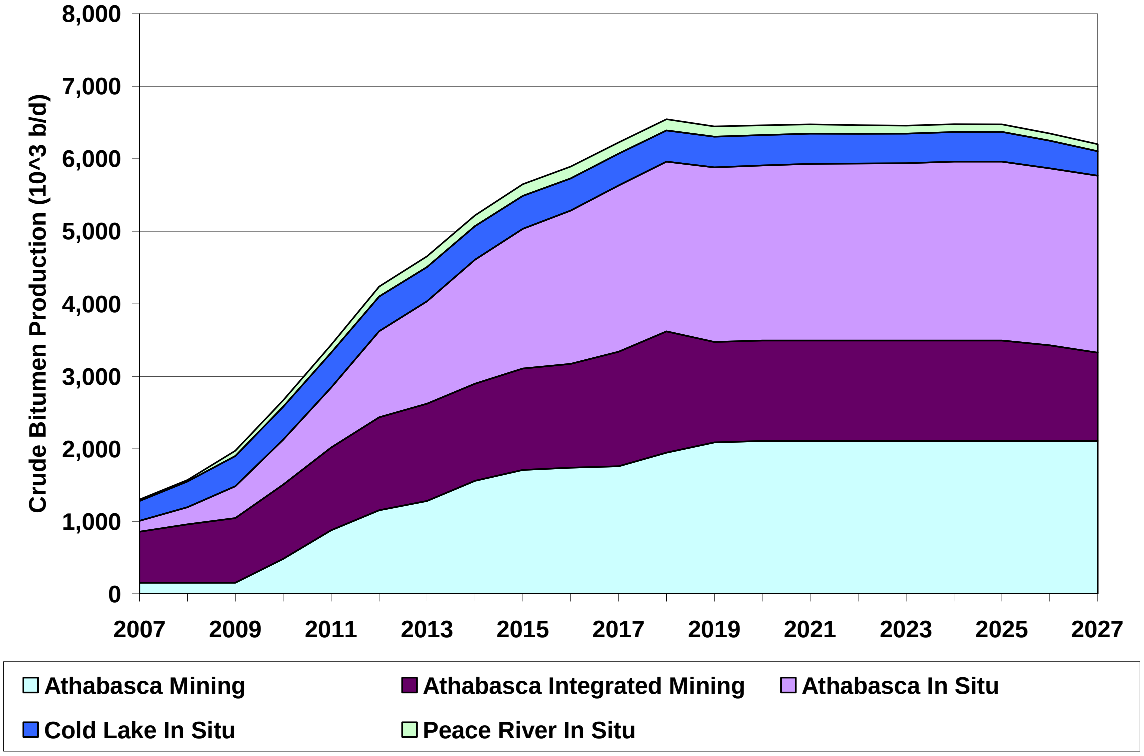
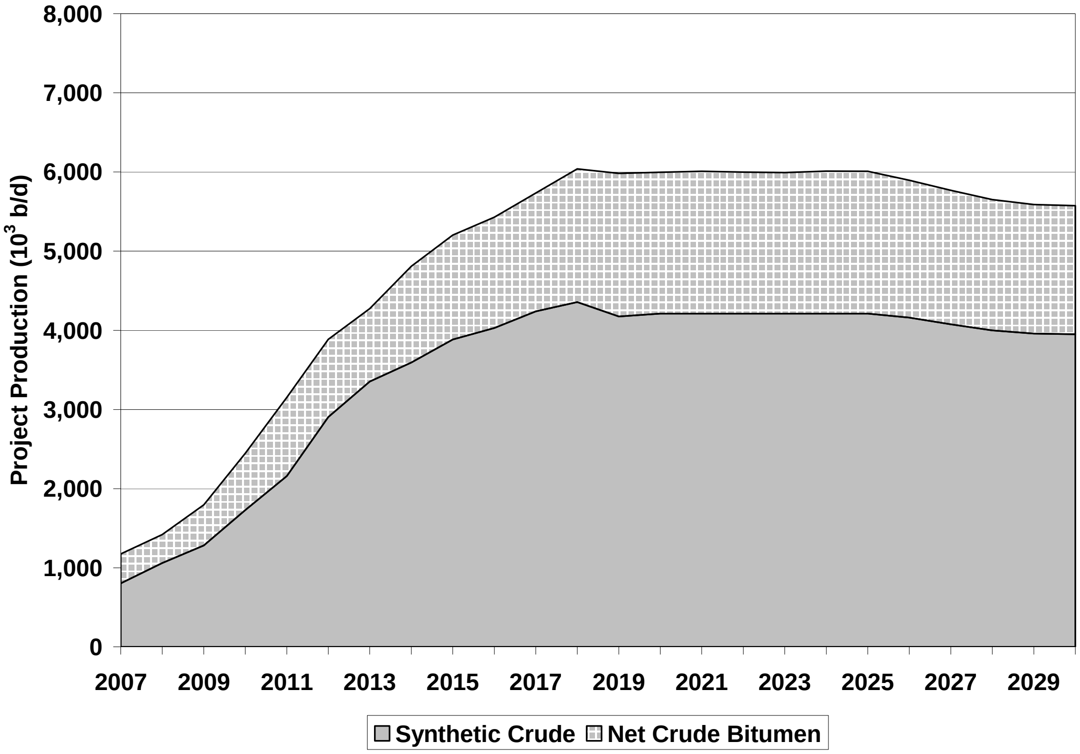


Figure 4.3
Synthetic Crude Oil and Crude Bitumen Production



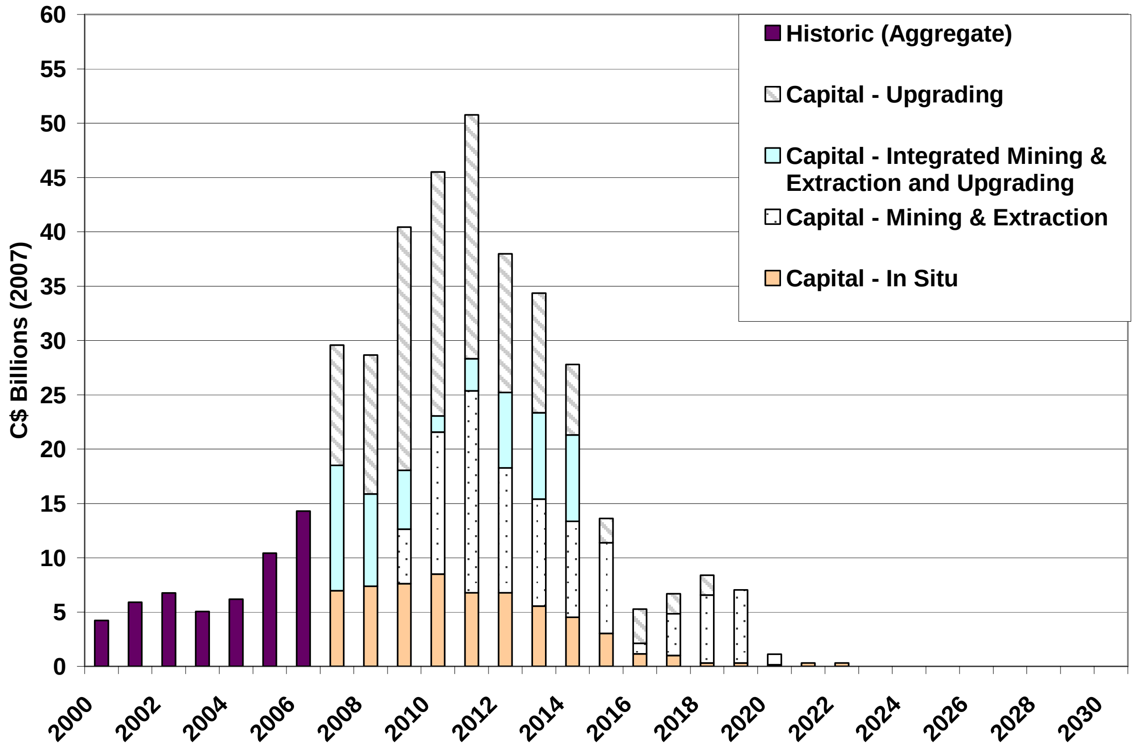
In order to estimate construction spending, we used unit capital costs (i.e., dollars spent per barrel per day of capacity), which are derived from public and private sources of information.

For the purpose of calculating investment in the oil sands, the initial capital cost ratios, in 2007 Canadian dollars, are as follows.

- $25,882 per barrel per day of gross bitumen production for in situ SAGD projects.
- $29,613 per barrel per day of gross bitumen production for in situ CSS projects.
- $48,085 per barrel per day of gross bitumen production for mining and extraction projects.
- $45,983 per barrel per day of synthetic crude oil production for upgrading projects.
- $98,889 per barrel per day of synthetic crude oil production for integrated mining and extraction and upgrading projects.

Since the majority of new in situ production capacity—over 90 percent of all existing and planned capacity—uses the SAGD technology, a weighted average was used to determine the capital expenditure for the projection model. The in situ capital costs are assumed to be C$26,255. We assumed that the first year of construction will incur 20 percent of the initial capital cost, and the second and third years of construction will each incur 40 percent. Operation begins at the end of the third year, just after the completion of the construction. The annual construction spending profile estimated thus, excluding on-going expenditures for maintenance, is presented in Figure 4.4.[10]

Figure 4.4
Estimated Capital Spending for Greenfield Projects (Investment Profile)
Unconstrained Projection



According to the Canadian Association of Petroleum Producers (CAPP), capital spending in the oil sands industry reached a maximum in 2006 of 14.3 billion dollars.[11] This high level of activity strained the Alberta economy and its labour supply. The capital spending is expected to continue and reach a maximum of C$51 billion dollars in 2011. This level of spending is much higher than the industry has been capable of achieving historically. From 2003 to 2005, oil sands spending doubled, if it were to continue to double every two years, one could expect oil sands capital spending to reach close to $40 billion dollars by 2011. Under such a doubling scenario, CERI's forecasted $51 billion dollars by 2011 may not be plausible.

[10] Historic values are provided by CAPP, and have not been inflated to 2007 dollars.
[11] CAPP Statistical Handbook, Table 4.16b
<www.capp.ca/default.asp?V_DOC_ID=1070&cookietest=true>

Market forces, notably inflation to both capital and labour, and available pipeline capacity may constrain oil sands development and result in the delay of projects, such that the Alberta economy is able to absorb the investment that will accrue to the province. Potential changes to provincial and federal environmental legislation (for GHG and other emissions, water management, land impacts, and other items), over the projection period will likely delay some projects and regulatory phases take longer to complete. These and other factors will result in this unconstrained projection, not coming to fruition.

It is important to note that not all of this investment takes place in Alberta. Modular construction and other factors result in some of this capital being spent outside the province. As part of CERI's estimates related to the economic impacts of oil sands projects on gross domestic product (GDP), about 80 percent of this investment will produce GDP impacts for the Canadian economy.[12] Hence, we developed more plausible projections considering potential delays and cancellations of projects, as discussed below.

4.1.2 Constrained Projections - Supply & Investment Projection

There are a number of factors that will likely hamper the announced expansion plans of oil sands operators, and in turn constrain the planned growth in production capacity. These include:

- future world oil supply/demand;
- availability of capital;
- availability and productivity of skilled construction workers;
- infrastructure limitations, such as pipeline availability and upgrading capacity;
- technology development;
- environmental concerns; and
- geopolitical effects.

In March 2008, Imperial Oil's Kearl oil sands project was put on hold as the federal government revoked a water permit for the oil sands facility. Without appropriate permits, Imperial Oil cannot proceed with dewatering of the mine site, as a stepping stone for site preparation. This could result in a lengthy delay for the mine. Future projects are likely to encounter increased resistance from environmental lobby groups that are likely viewing this setback as a victory in their campaign against "unrestricted" oil sands development. This could result in increased intervention in regulatory hearings, more stringent regulatory process, and increased costs and delays for future oil sands projects.

Due to these factors, not all projects included in the Unconstrained Projection may begin operations as anticipated, or even go ahead into operation. We developed two Constrained projections by applying various delays and probabilities to each of the announced projects, relative to their planned start up date and production capacity. The delays and probabilities

[12] G. Timilsina, N. LeBlanc, T. Walden, "Economic Impacts of Alberta's Oil Sands, Volumes I and II". Canadian Energy Research Institute, August 2005.

applied correspond to the projects position in the regulatory process. Projects further along the regulatory process are given small delays and high probabilities of proceeding to their announced production capacity.

Upfront delays, measured in years, postpone project start-up dates by the specified amounts of time. This scenario for delays is reflected in the *Constrained Projection*.

The second Constrained projection is also included. This Projection represents the delays in production that could result from a government policy which causes increased delays to the projects that have been announced.

Multipliers, or probabilities, are applied to the planned production capacity to get an adjusted production projection. These multipliers are the estimated probabilities of projects actually going into operation. They are applied to planned production capacity in each category to derive expected production.

The *Constrained Projection with Double Delays and Capacity Curtailments* takes into account delays and probabilities—or capacity curtailments. This represents the methodology that was generally accepted by industry at the time of CERI's inaugural oil sands study in 2004.[13] As the oil sands have continued to develop there is a need to revise the previous methodology, to no longer rely solely on capacity curtailments as a proxy for project cancellations. Previously, this was used to assist in representing possible project cancellations. Monitoring of oil sands projects over the past several years has produced project delays and process modifications, but there have been no project cancellations or capacity curtailments.[14] This is a scenario that is not likely to pan out as most of the project announcements taken into consideration as part of our project model comprise of areas of oil sands lease areas with strong potential for oil sands production. If the WTI price of oil falls below the supply cost for Greenfield projects it is possible that projects will be cancelled if wages and capital costs are sticky in the long-term and do not fall at a corresponding rate. Economic theory supports this statement, as such we will continue to depict the Constrained projection with curtailments to proxy this scenario.

In summary, there are now two Constrained projections being considered:

Constrained Projection

Constrained Projection with Double Delays and Capacity Curtailments – "Projection Reference Case"

[13] R.B. (Bob) Dunbar, Melanie Stogran, Pauline Chan, and Kok-sum (Sam) Chan. *Oil Sands Supply Outlook: Potential Supply and Costs of Crude Bitumen and Synthetic Crude Oil in Canada, 2003-2017,* March 2004.

[14] While some people may argue that Synenco's announcement to revisit their mining project is a project cancellation, a review of the wording used by Synenco leads us to believe that their statements reflect a desire to revisit their timelines and methods for modular construction to ensure the facility is built on time, at a reasonable cost and meets all Canadian safety standards. Given this announcement, the project will be delayed for a period of time, yet to be determined.

Delays and probabilities (where appropriate) for each phase of the regulatory approval process are based upon reasonable estimates of how long each phase could take, and are as follows:

- projects operating or under construction - 1-year time delay (2-years under the double delay Projection) for mining projects, no time delay for in situ projects; 100 percent probability multiplier for production;

- projects approved – 1-year time delay (2-years under the double delay Projection); 90 percent probability multiplier for production;

- projects in the application process - 3-year time delay (6-years under the double delay Projection) for mining projects and 1-year time delay (2-years under the double delay Projection) for in situ projects; 80 percent probability multiplier for production;

- projects at disclosure stage - 4-year time delay (8-years under the double delay Projection) for mining projects and 2-year time delay (4-years under the double delay Projection) for in situ projects; 75 percent probability multiplier for production; and

- projects identified as announced - 4-year time delay (8-years under the double delay Projection) for mining projects and 3-year time delay (6-years under the double delay Projection) for in situ projects; 60 percent probability multiplier for production.

The phases of the regulatory process are defined as:

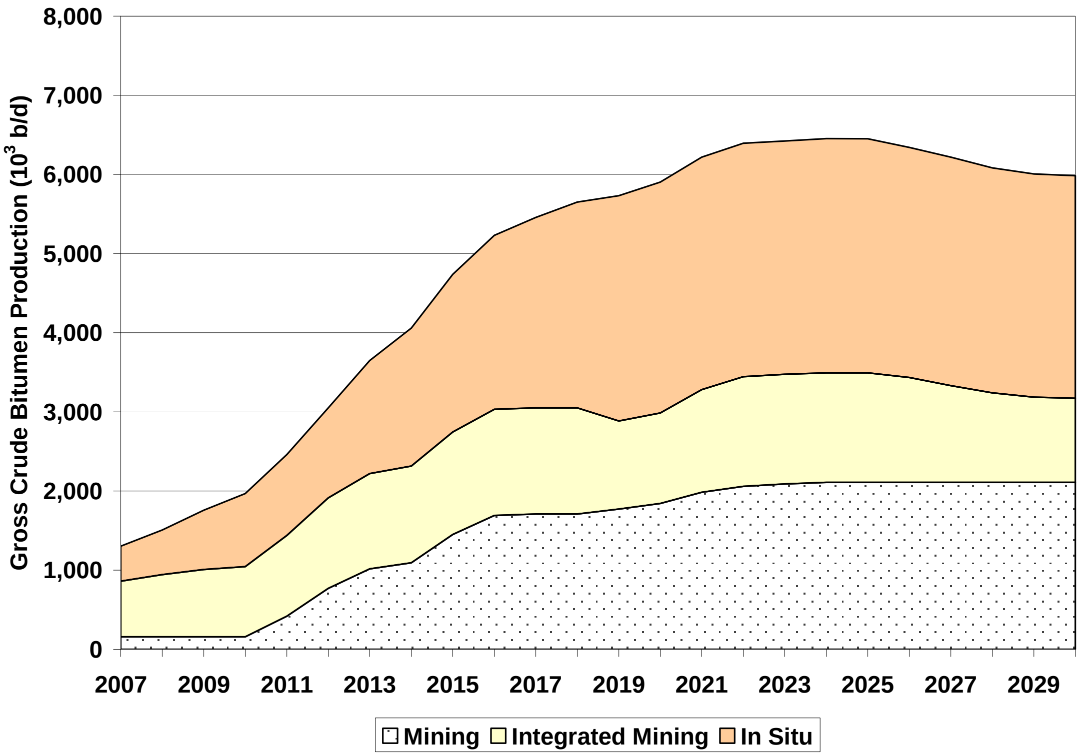
- operating – Construction has been completed and start-up of operation has begun;
- under construction – Construction of the facilities has begun;
- approved – Application has been approved by the appropriate regulatory bodies;
- application process – Oil Sands Application and Environmental Impact Assessment (EIA) has been filed with the AEUB and Alberta Environment;
- disclosure – Disclosure document for the project defining the terms of reference of the EIA has been released; and
- announced – Operators' plans for development have been publicly announced.

Applying these adjustments to the Unconstrained Projection allows us to form alternate projections - ones that, given historic capital spending and annual capacity additions, are attainable under projected economic conditions.

4.1.2.a Constrained Projection

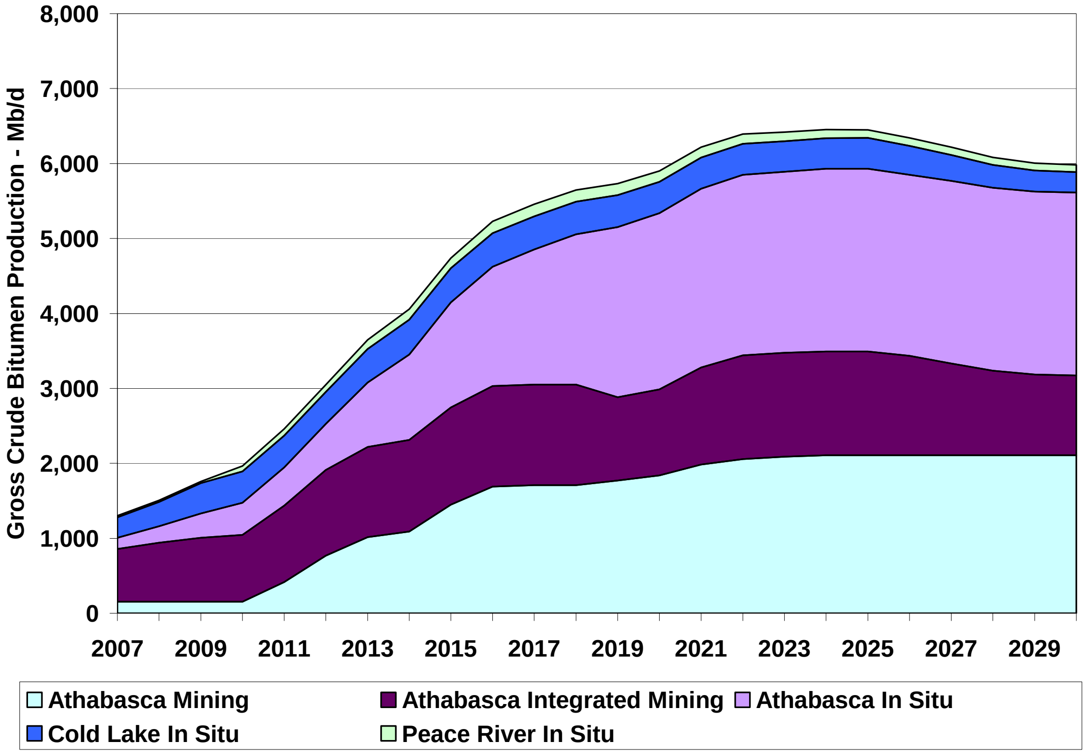
The Constrained projection reaches a total bitumen production of 6.1 MBPD by 2030. Production from both surface mining and thermal in situ operations increases over the projection period, as shown in Figure 4.5.

Figure 4.5
Constrained Gross Crude Bitumen Production



With the delays used in the Constrained projection, the growth in oil sands developed is slowed over the projection period. By 2015, oil sands production is almost 1 MBPD lower than in the unconstrained case. By 2026, all the projected that had been delayed will have come online and oil sands production will have achieved unconstrained production levels. Figure 4.6 presents the production projection broken down by region.

Figure 4.6
Constrained Gross Crude Bitumen Production (By Region and Type)



Under this Constrained projection, Table 4.2, crude bitumen upgraded in Alberta will increase from 774,000 BPD in 2007 to 4.4 MBPD in 2030. As a result, synthetic crude oil production will increase from 802,000 BPD in 2007 to 4.0 MBPD in 2030. Net bitumen production (not upgraded) will increase from 390,000 BPD in 2007 to 1.6 MBPD in 2030. Total net production (net bitumen plus synthetic crude oil) will increase from 1.2 million MBPD in 2007 to 5.6 MBPD in 2030. SCO production is graphically presented in Figure 4.7.

Figure 4.7
Constrained SCO Bitumen Production

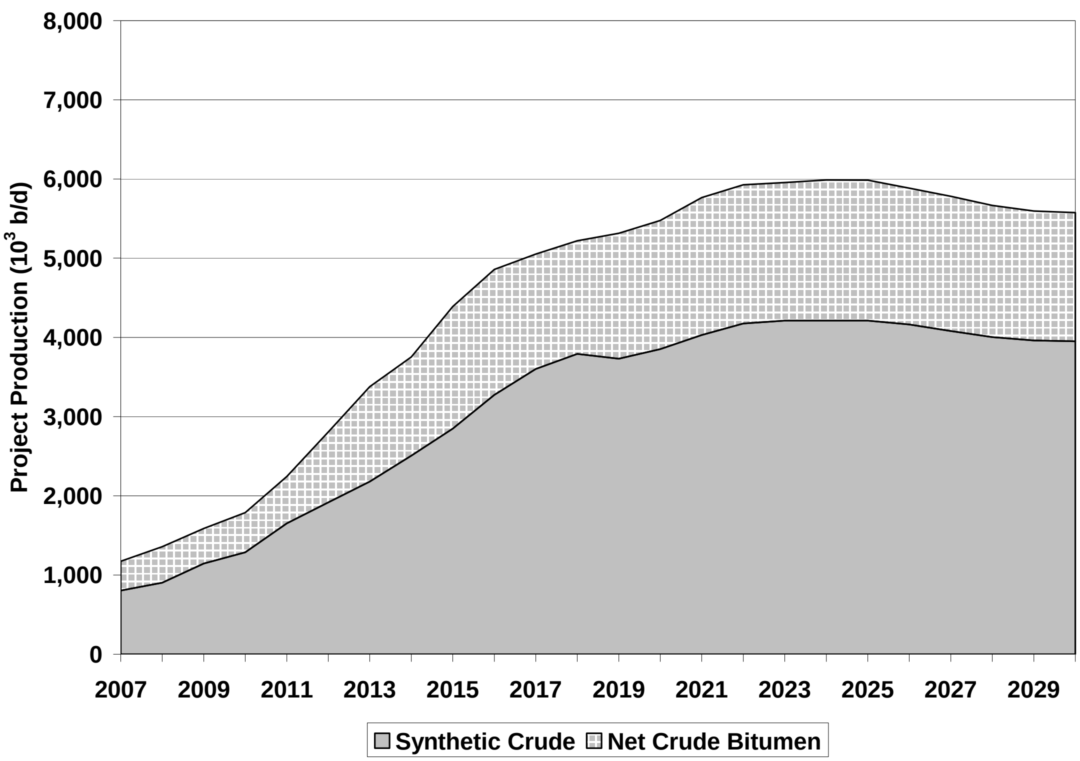
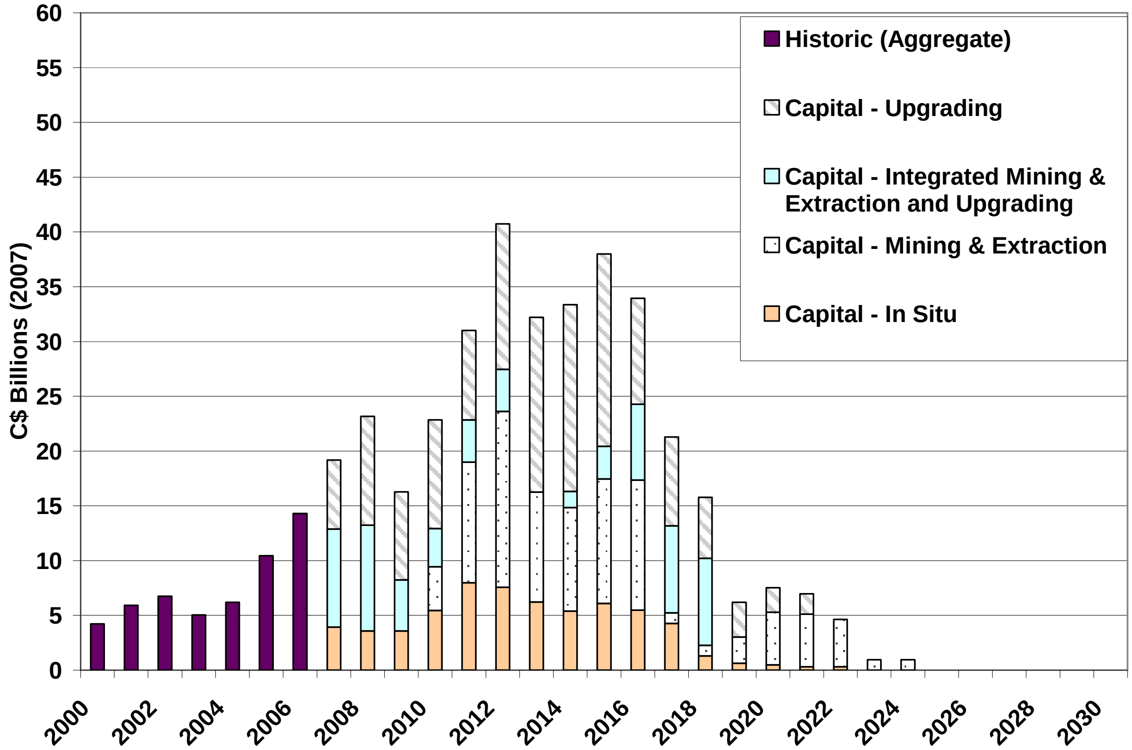


Table 4.2
Constrained Production Profiles
(thousand barrels per day)

Year	Gross Bitumen Production	Bitumen Sent to Upgraders	Net Bitumen Production	SCO Production	Total Products to Market
2007	1,300	929	371	802	1,173
2008	1,506	1,048	457	902	1,359
2009	1,757	1,315	443	1,146	1,589
2010	1,966	1,464	502	1,285	1,787
2011	2,459	1,866	593	1,652	2,244
2012	3,049	2,161	888	1,917	2,805
2013	3,647	2,449	1,199	2,178	3,377
2014	4,058	2,809	1,248	2,506	3,754
2015	4,738	3,196	1,543	2,847	4,390
2016	5,230	3,648	1,582	3,276	4,858
2017	5,456	4,005	1,450	3,601	5,051
2018	5,649	4,221	1,429	3,792	5,220
2019	5,731	4,145	1,586	3,731	5,316
2020	5,902	4,277	1,625	3,852	5,477
2021	6,217	4,480	1,737	4,029	5,766
2022	6,394	4,641	1,753	4,174	5,927
2023	6,422	4,678	1,744	4,211	5,955
2024	6,454	4,678	1,776	4,211	5,987
2025	6,451	4,678	1,773	4,211	5,985
2026	6,342	4,618	1,724	4,162	5,886
2027	6,218	4,517	1,701	4,081	5,781
2028	6,084	4,423	1,661	4,004	5,665
2029	6,005	4,370	1,635	3,962	5,597
2030	5,982	4,356	1,626	3,950	5,576
Total Projection Period	**41,981,274**	**30,285,241**	**11,696,033**	**27,186,003**	**38,882,036**

Construction spending is estimated for this Constrained projection, using the same capital spending estimate that was used for the Unconstrained projection. Constrained capital spending is shown in Figure 4.8, and reflects the oil sands projection. The lack of any spending for Greenfield by 2025 is not to represent a downturn in industry activity, merely a lack of any new project announcements for this timeframe.

Figure 4.8
Constrained Estimated Capital Spending for Greenfield Projects (Investment Profile)



4.1.2.b Constrained Projection with Capacity Curtailments & Double Delays – Projection Reference Case

The Constrained Projection with Capacity Curtailments and Double Delays reaches a total bitumen production of just under 5.0 MBPD by 2030. Production from both surface mining and thermal in situ operations increases over the projection period, as shown in Figure 4.9.

With these multipliers and delays used in the projection, production is 1 MBPD lower from 2015 to 2030, when compared to the Constrained projection.

Figure 4.9
Projection Reference Case, Gross Crude Bitumen Production
Constrained Projection with Capacity Curtailments

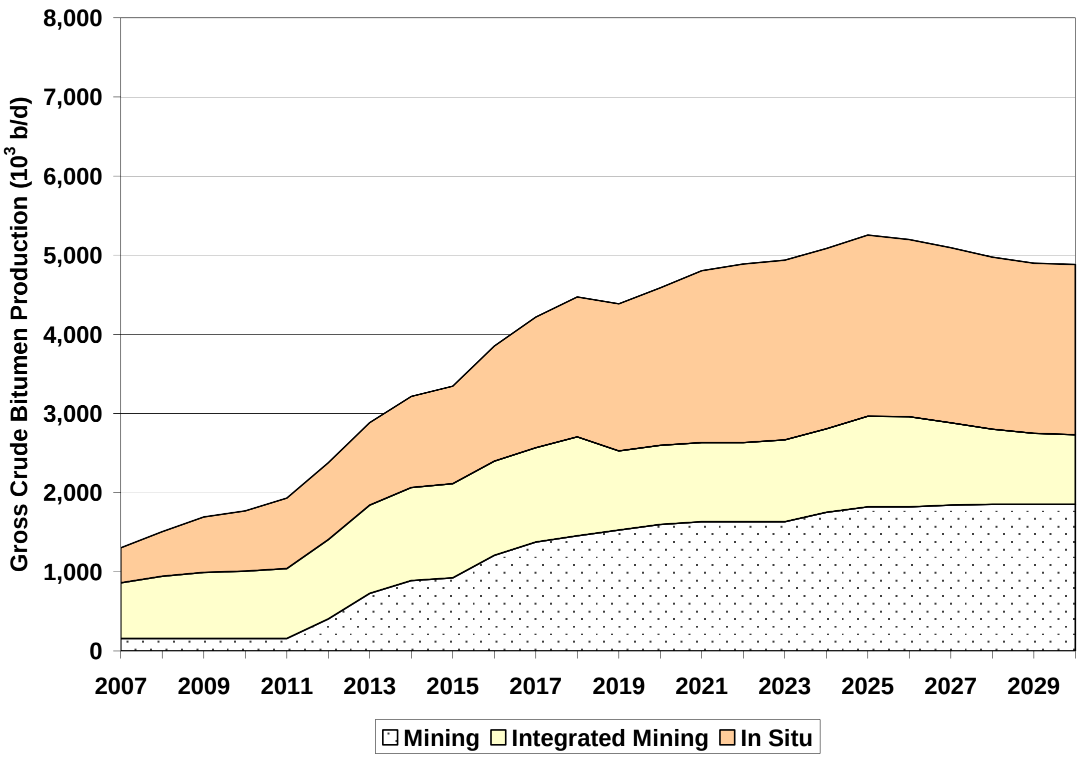
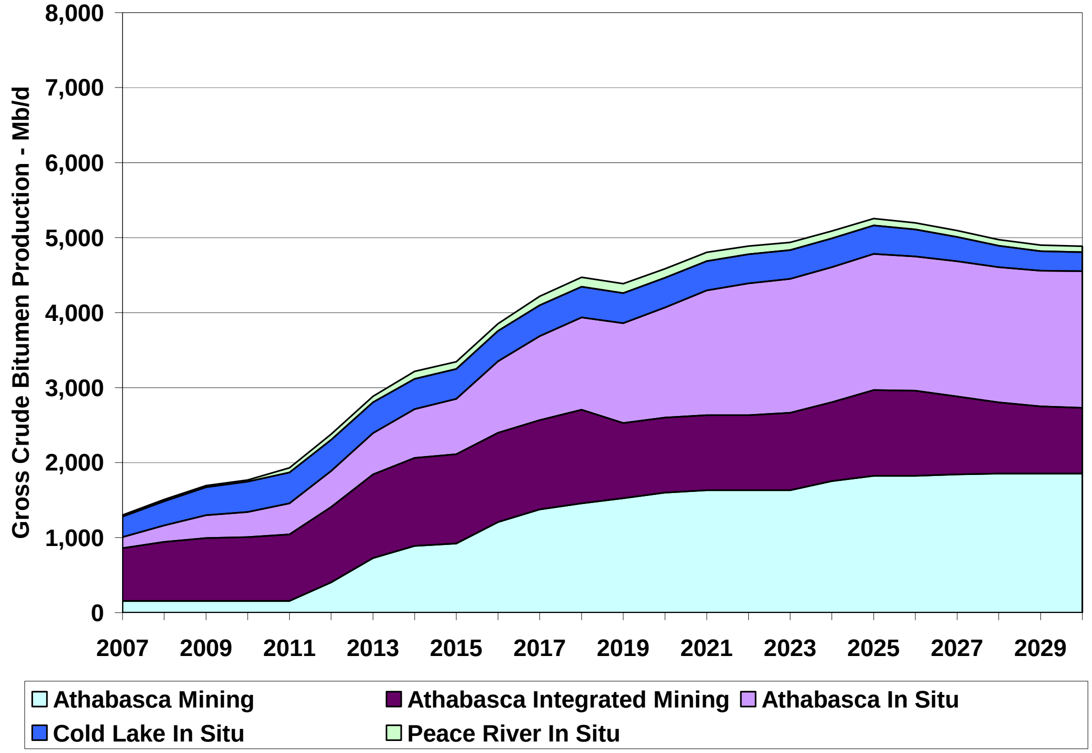


Figure 4.10
Projection Reference Case, Gross Crude Bitumen Production
Constrained Projection with Capacity Curtailments



Under this projection, Table 4.3, crude bitumen upgraded in Alberta will increase from 929,000 BPD in 2007 to 3.6 MBPD in 2030. As a result, synthetic crude oil production will increase from 802,000 BPD in 2007 to 3.3 MBPD in 2030. Net bitumen production (not upgraded) will increase from 390,000 BPD in 2007 to 1.3 MBPD in 2030. Total net production (net bitumen plus synthetic crude oil) will increase from 1.2 MBPD in 2007 to 4.6 MBPD in 2030. SCO production is graphically presented in Figure 4.11.

Figure 4.11
Projection Reference Case, SCO Bitumen Production
Constrained Projection with Capacity Curtailments

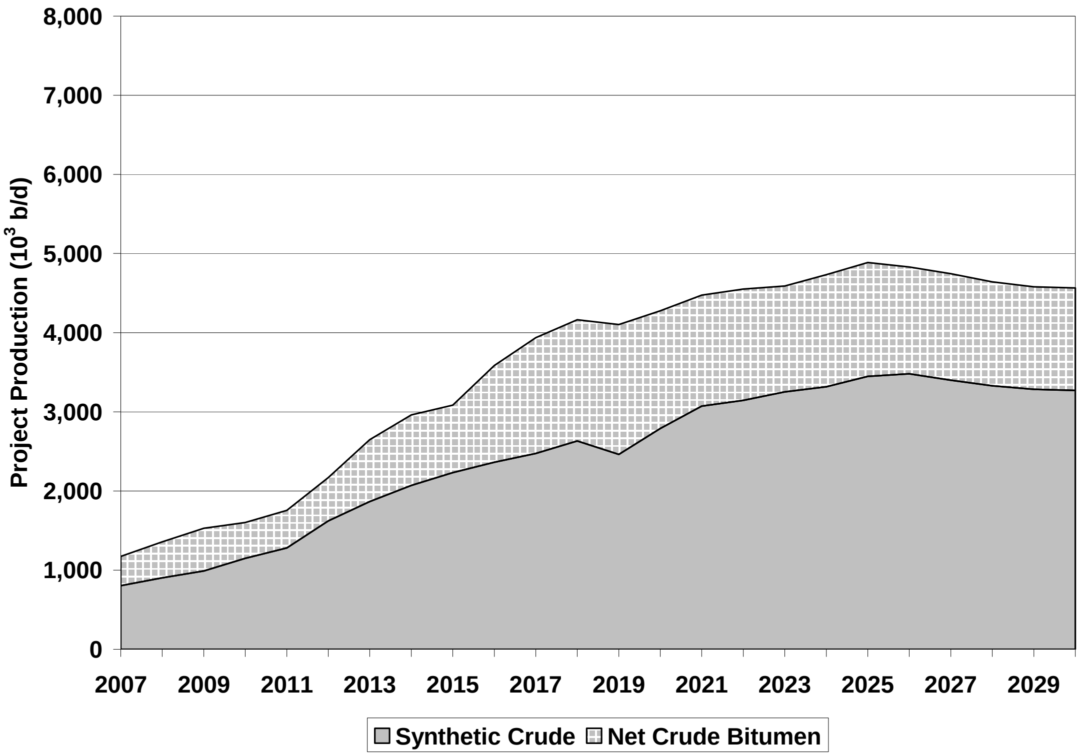
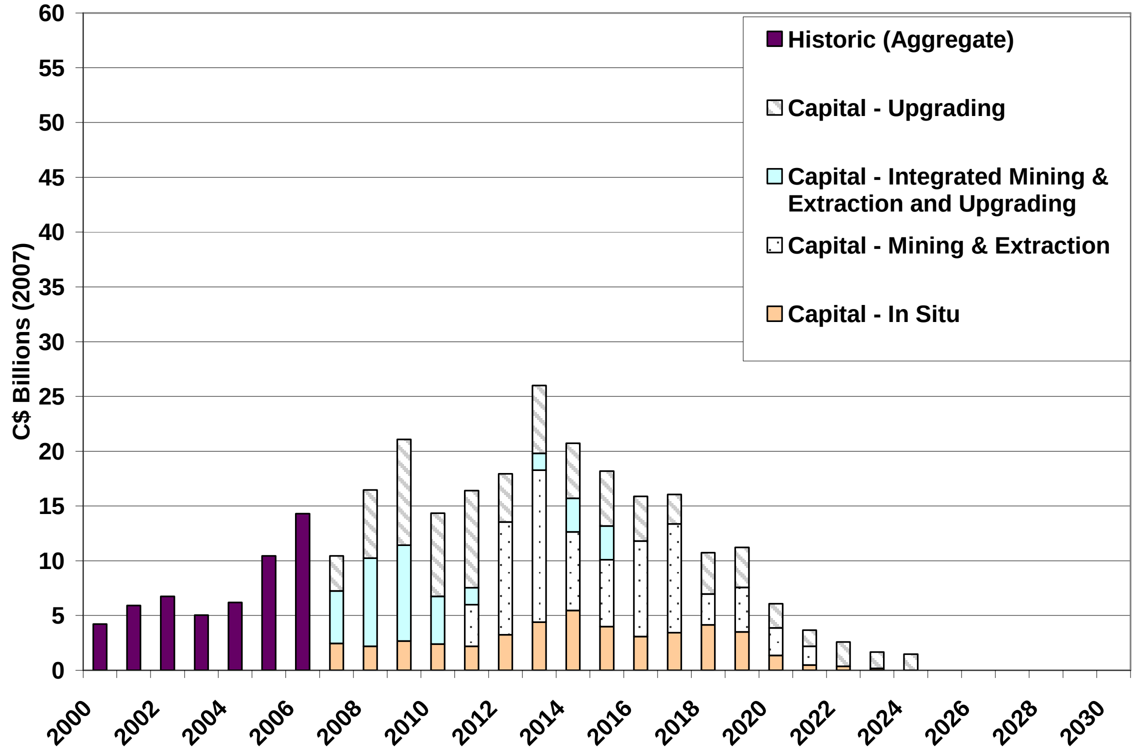


Table 4.3
Projection Reference Case, Production Profiles (thousand barrels per day)
Constrained Projection with Capacity Curtailments

Year	Gross Bitumen Production	Bitumen Sent to Upgraders	Net Bitumen Production	SCO Production	Total Products to Market
2007	1,300	929	371	802	1,173
2008	1,506	1,048	457	902	1,359
2009	1,693	1,154	539	989	1,528
2010	1,769	1,318	451	1,149	1,600
2011	1,931	1,458	473	1,280	1,753
2012	2,377	1,831	546	1,622	2,168
2013	2,885	2,102	782	1,867	2,649
2014	3,216	2,326	890	2,072	2,962
2015	3,344	2,492	852	2,231	3,083
2016	3,853	2,630	1,223	2,362	3,586
2017	4,219	2,754	1,464	2,474	3,938
2018	4,471	2,941	1,530	2,632	4,162
2019	4,386	2,745	1,640	2,463	4,103
2020	4,586	3,097	1,489	2,789	4,278
2021	4,803	3,403	1,401	3,072	4,473
2022	4,887	3,482	1,405	3,145	4,550
2023	4,936	3,601	1,336	3,253	4,589
2024	5,086	3,669	1,417	3,315	4,733
2025	5,254	3,819	1,435	3,450	4,885
2026	5,197	3,847	1,351	3,480	4,830
2027	5,094	3,750	1,344	3,402	4,746
2028	4,975	3,659	1,315	3,328	4,643
2029	4,899	3,606	1,294	3,284	4,578
2030	4,884	3,589	1,295	3,271	4,566
Total Projection Period	**33,416,334**	**23,816,433**	**9,599,901**	**21,401,182**	**31,001,083**

Construction spending is estimated for this projection, using the same capital spending estimate that was used for the Unconstrained projection. Constrained capital spending is shown in Figure 4.12, and reflects a slower growth in capital spending, paralleling the slower growth in oil sands production.

Figure 4.12
Projection Reference Case, Estimated Capital Spending for Greenfield Projects (Investment Profile)
Constrained Projection with Capacity Curtailments



4.2 Projection Comparisons

Figure 4.13 illustrates the differences between a wide variety of oil sands projections.

- CERI: Constrained and Reference Case.
  - Data is updated to January 2008.
- Canadian Association of Petroleum Producers (CAPP) Moderate Growth and Pipeline Planning Cases.[15]
  - Data is updated to early 2007, oil sands projections extend to 2020.
- National Energy Board (NEB), All Projects and Base Case.[16]
  - Data is updated to late 2006, oil sands projections extend to 2015.
- Alberta Energy and Utilities Board (AEUB), Alberta Crude Bitumen Production projection.
  - Data is updated to late 2006.

Most of the projections use a methodology similar to CERI—stacking up the announced projects and applying some delays. The highest and lowest projects have been removed from the figure and have not been presented. These were CERI's Unconstrained projection and the NEB's Low Case which had production by 2015 at 1.9 MMBPD.

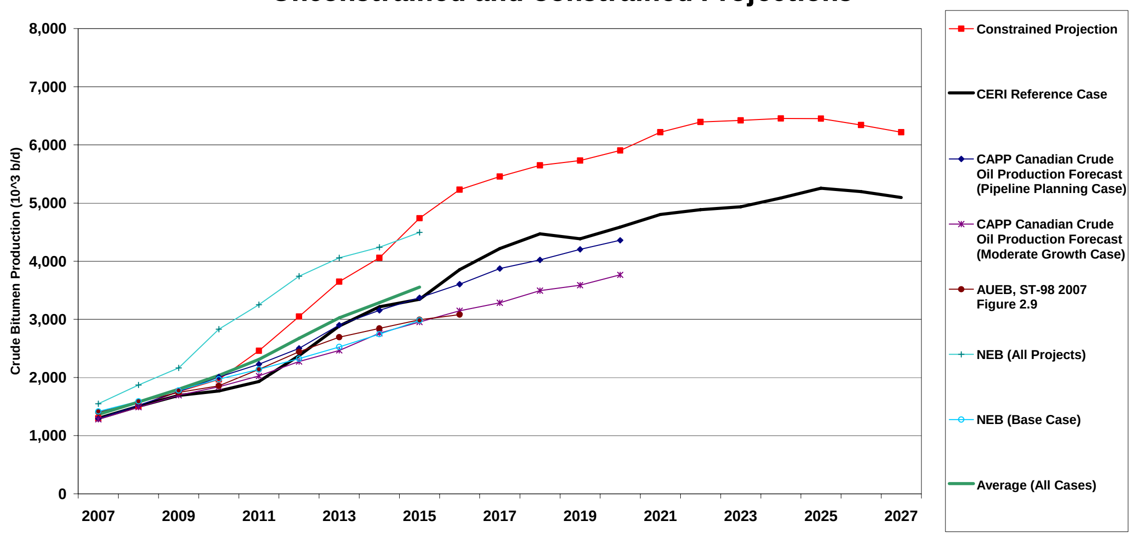
The comparison has been used to reinforce CERI's selection of our Reference Case. CERI's Reference Case reflects the Constrained Projection with Capacity Curtailments. The data in CERI's databases contain at least 6 months worth of project announcements that are taken into account by CAPP, the NEB and the AEUB. As is illustrated in Figure 4.13, CERI's Reference Case follows a path and trend similar to the average of the NEB, CAPP, AUEB, and CERI's projections that are provided in the figure.

In 2018 Suncor's original mine site is assumed to go off-line, without any replacement production. This assumes a 40 year life of the original mine with a 1978 start date. This is reflected in the noticeable dip in 2018 for production, gas use, and emissions.

[15] Canadian Association of Petroleum Producers, "Crude Oil Forecast, Markets, and Pipeline Expansions", June 2007,.

[16] "Canada's Energy Future – Reference Case and Scenario's to 2030", NEB, http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2007/nrgyftr2007-eng.html#lot.

Figure 4.13
Unconstrained and Constrained Projections



4.3 Oil Sands Natural Gas Consumption

The oil sands industry consumes substantial amounts of natural gas during production and upgrading activities. In 2006, the oil sands industry accounted for approximately 1.0 Bcf/d of natural gas demand, slightly more than 40 percent of Alberta's total natural gas demand.[17] As production levels increase, natural gas consumption will also increase, unless low GHG technologies are implemented.

Thermal and electricity needs of mining and extraction projects and upgraders will be met through cogeneration units, designed to follow the thermal load of the project. Whether they burn natural gas or another feedstock remains to be seen over the projection period. In situ projects are a different matter. Recent applications include the intent to move forward with cogeneration. However, this introduces additional risk to the in situ operator. The open electricity market and increased exposure to natural gas price volatility.

For the purpose of this section, we will assume that in situ projects with operating dates beyond 2007 do not use cogeneration; those prior to 2007 will be assumed to include cogeneration (following the thermal requirements of the oil sands project) with the exception of EnCana's Christina Lake and Foster Creek projects which do not use cogeneration.

Table 4.4 is a reproduction of Table 2.2 and presents natural gas consumption by oil sands technology:

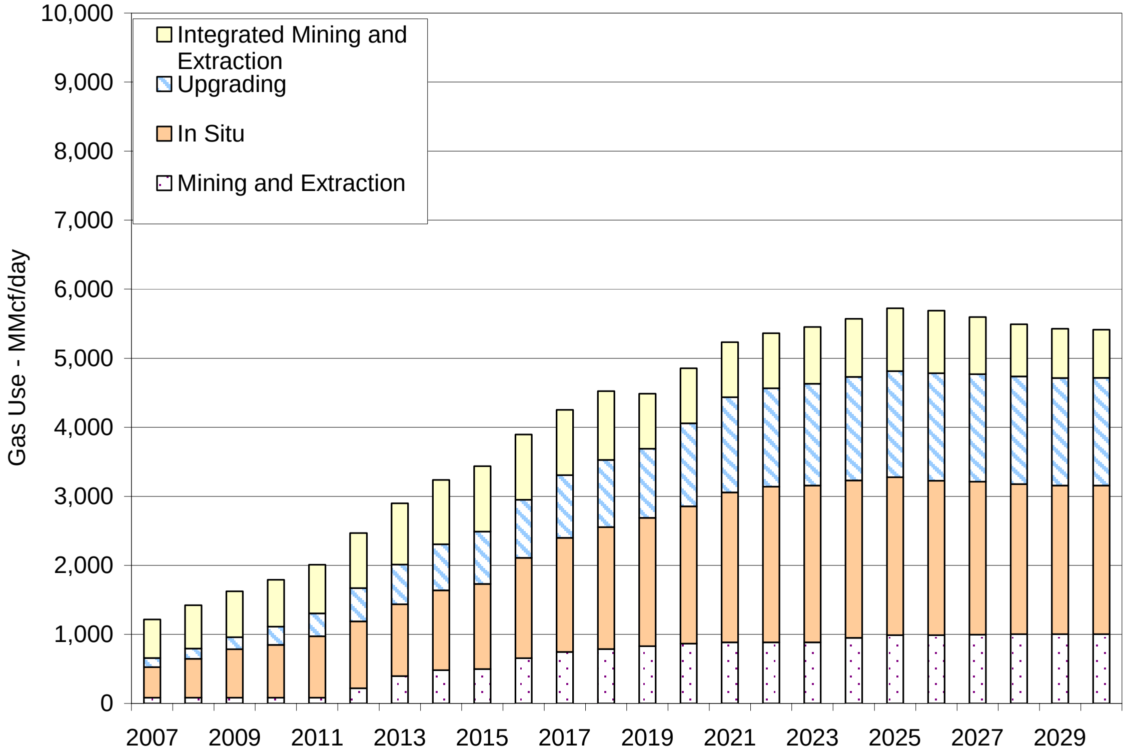
[17] AEUB ST-98, AND CAPP.

Table 4.4
Oil Sands Natural Gas Requirements and Purchases

	Natural Gas Requirements Mcf/bbl (GJ/bbl)		Natural Gas Purchases Mcf/bbl (GJ/bbl)	
	No Cogeneration	Cogeneration	No Cogeneration	Cogeneration
CSS	1.1 (1.2)	2.0 (2.1)	1.0 (1.1)	1.8 (1.9)
SAGD	1.0 (1.1)	1.6 (1.7)	1.0 (1.1)	1.6 (1.7)
Mining & Extraction		0.5 (0.5)		0.5 (0.5)
Upgrading Mcf/bbl of SCO (GJ/bbl of SCO)		0.9 (0.9)		0.6 (0.6)
Integrated Mining & Extraction and Upgrading Mcf/bbl of SCO (GJ/bbl of SCO)		1.0 (1.0)		0.7 (0.7)

Projections for natural gas purchases are provided in Figure 4.14, which represents the oil sands industry relying completely on natural gas over the projection period. Alternative scenarios that analyze alternative fuels will be discussed in Part IV and V. Since many of these technologies are commercially available, it isn't likely that the oil sands will continue to rely solely on natural gas over the projection period. The integrated in situ Longlake project is scheduled to rely primarily on a synthetic gas to meet most of their natural gas needs. This project is scheduled to come online sometime in 2008.

Figure 4.14
Total Natural Gas Purchases – CERI Reference Case



When all projects prior to 2007 use natural gas fueled cogeneration (with the exception of EnCana which has no cogeneration) and all new in situ projects after and including 2007 rely on purchased electricity, the total amount of natural gas purchased will almost reach 6,000 MMcf/day by 2025. This represents over a 400 percent increase from current levels.

Table 4.5
Reference Case Natural Gas Purchases (mmcf/d)

Year	Projection Reference Case
2007	1,460
2008	1,665
2009	1,870
2010	2,034
2011	2,251
2012	2,712
2013	3,141
2014	3,482
2015	3,680
2016	4,139
2017	4,497
2018	4,767
2019	4,730
2020	5,099
2021	5,475
2022	5,604
2023	5,695
2024	5,814
2025	5,967
2026	5,933
2027	5,841
2028	5,735
2029	5,671
2030	5,659

4.4 Oil Sands Emissions

To avoid presenting a bias, CERI is relying upon the CO_2e emissions resulting from the burning of a pipeline spec natural gas. We make no assumptions pertaining to "cleaning" of the flue emissions prior to release into the atmosphere. This has been done intentionally since it will provide for a clear comparison with emissions from the alternative fuel sources to be presented in Part III of this study.

For the purpose of this analysis, we are considering the emissions produced from the burning of marketable natural gas. As a guide for calculating the emissions, we are relying upon information published by Environment Canada as part of their National Inventory Report on greenhouse gases.[18] The Global Warming Potential (GWP) factors we are relying upon include a guide developed by CAPP and published April 2003.

Natural Gas Emissions Factors for Electric Utilities as reported by Environment Canada, in g/m3 of natural gas[19] are listed in Table 4.6, where CO_2 is 1891, CH_4 is 0.49, N_2O is 0.049 g/m^3 of natural gas. Using CAPP's reported GWP factors of 1 for CO_2, 21.0 for CH_4 and 310 for N_2O we calculate a CO_2e for natural gas equal to 1.92 kg/m^3, which equates to a GWP for natural gas of approximately 51.36 kg CO_2e/GJ:

Table 4.6
Natural Gas – Global Warming Potential

	Emissions (g/m3)	Global Warming Potential
CO2	1891	1
CH4	0.49	23
N20	0.049	296
		1.92 kg / m3
		51.36 kg CO2e/GJ

Throughout the rest of this report we will rely on this GWP value to determine the amount of CO2e emissions produced by the oil sands industry. Of course, this value assumes that none of flue gases associated with an oil sands project is captured. As we will discuss in Parts III and IV, the flue gases can be captured (for a price) and sequestered or "cleaned" such that the CO_2 can be used for Enhanced Oil Recovery (EOR). For purposes of calculating emissions compliance costs – as part of our supply costs assessments – we shall rely upon the CO_2e value.

[18] http://www.ec.gc.ca/pdb/ghg/inventory_repo5555rt/2005_report/a12_eng.cfm#ta12_1, January 15, 2008.

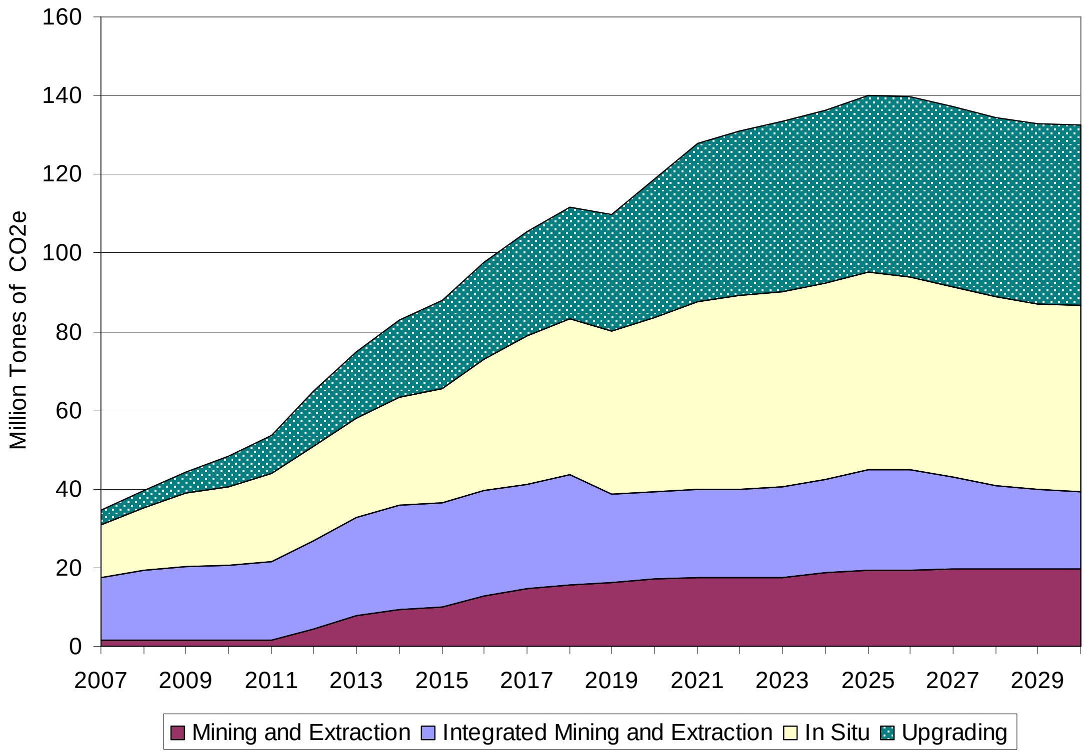
[19] Assumed combustion efficiency of 99.5 percent.

4.4.1 Emissions Projections

In order to understand the emissions from the oil sands we need to first look at the total direct emissions—associated with the use of natural gas (purchased and produced, where produced is assumed to have the same characteristics as the purchased gas). A more complete understanding of the oil sands emissions could involve a life-cycle assessment (LCA) that would account for the emissions from construction and operations (including vehicle fleets).

The direct emissions are shown below, and not surprisingly rise along with the projected increase in oil sands production and natural gas use as shown previously.

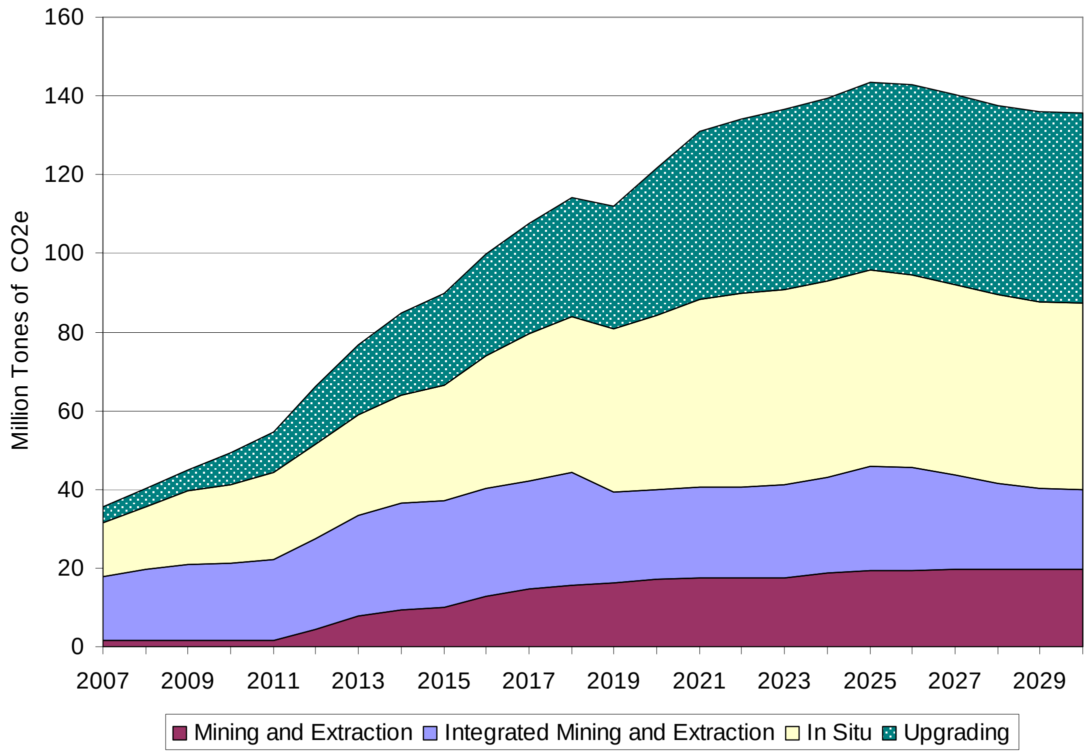
Figure 4.15
Reference Case Direct Emissions Projection



These emissions are based upon the required natural gas for the oil sands. Since this gas is used for the production of two sources of energy (thermal and electric) from a single fuel source, it is inherently more energy efficient than having two stand alone facilities producing the same outputs. The Alberta Government's Specified Gas Emitters regulations calculate a "deemed" emissions, which is not reflective of actual emissions nor does it take into account the efficiencies associated with producing two outputs from a single source of energy. Using the regulation would produce a "deemed" emissions level that far exceeds actual emissions, and would produce an upward bias in results. To avoid such a bias, emissions are calculated strictly upon the natural gas required by a project and electricity purchased by a project.

For those oil sands projects requiring purchased electricity we have assumed that the emissions from the facility would reflect the Alberta grid intensity. Since Alberta's electricity system is heavily weighted to coal fired power plants, the grid intensity is higher than if it was purchased from a natural gas (or cogeneration) facility. A grid intensity of 0.65 T of CO2e/MWh has been assumed.

Figure 4.16
Direct and Indirect Emissions



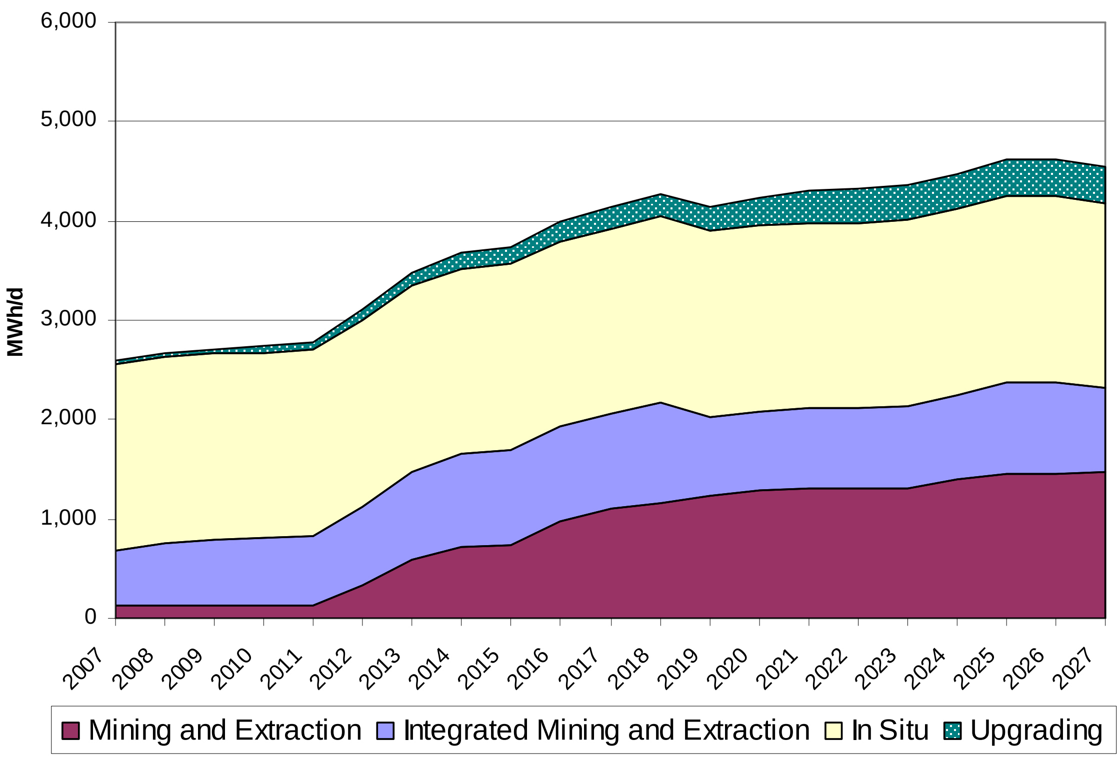
Over the projection period, an average of 2 million tones per year is attributable to indirect emissions associated with the purchase of electricity from the Alberta system. Comparing emissions projections is an inherently unreliable process, unless the assumptions underpinning two projections are similar. CERI's oil sands projection is based upon an assumption that oil sands growth will experience some delays, but otherwise be robust. Using CERI's Reference Case for oil sands production and the emissions from the above figure, the oil sands industry accounted for 5 percent of Canada's total GHG emissions in 2007,[20] compared to 24 percent coming from the transportation sector. By 2015 the oil sands could account for 12 percent of Canada's GHG emissions, assuming current natural gas use continues.

[20] 93 megatonnes of CO_2e is 12 percent of the NEB's forecasted 743.7 megatonnes of CO_2e as reported in Figure 3.22 of "Canada's Energy Future – Reference Case and Scenarios to 2030". http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2007/nrgyftr2007-eng.html

Cogeneration units could purchase electricity from the Alberta grid, or from other cogeneration operators in Northern Alberta using power purchase agreements, if there is sufficient cogeneration capacity. Since the electricity would still enter into the Alberta system (unless a merchant "point-to-point" electricity transmission line was built) the emissions intensity could still reflect the grid intensity of 0.65 T of CO2e / MWh.

Figure 4.17 depicts the electricity generating capacity from the oil sands.

Figure 4.17
Reference Case Electricity Generated—Cogeneration—Projection

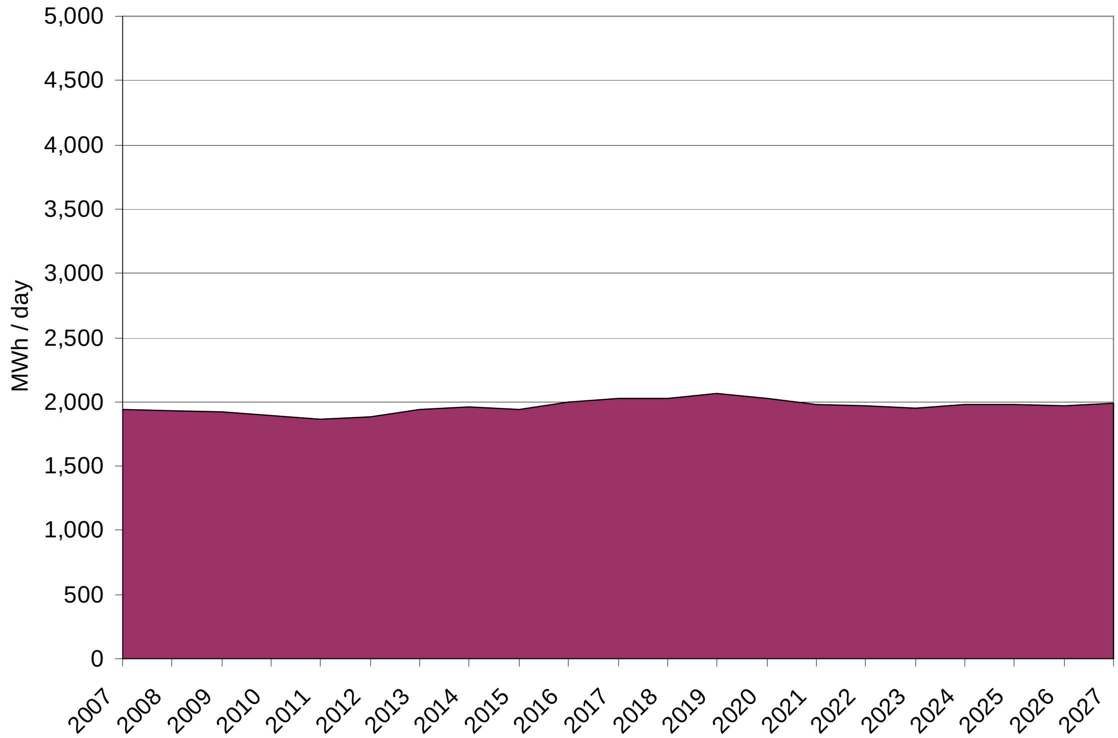


This amount of electricity generation exceeds the requirements of the oil sands industry. In situ operators with cogeneration produce a substantial surplus. Table 4.7 illustrates the surplus or shortage of electricity on a per barrel basis for the various oil sands methods of extracting and upgrading.

Table 4.7
Surplus or Shortage Of Electricity per Barrel

	Project Capacity (bbl/d)	Generated MWh/bbl	Demanded MWh/bbl	Surplus/Shortage MWh/bbl
CSS	30,000	0.140	0.010	0.130
CSS without Cogen	30,000	0.000	0.010	0.000
SAGD	30,000	0.128	0.010	0.118
SAGD without Cogen	30,000	0.000	0.010	0.000
Stand Alone Mining and Extraction	100,000	0.019	0.012	0.007
Stand Alone Upgrader (SCO)	100,000	0.004	0.008	-0.004
Integrated Mining and Extraction and Upgrading (SCO)	100,000	0.011	0.022	-0.011

Figure 4.18
Reference Case Electricity Surplus Projection



If all the electricity generated by oil sands projects and upgraders was purchased by these facilities, there would still be an excess of electricity from the oil sands, as depicted in Figure 4.18. This is likely an additional factor influencing the development of cogeneration units for in situ projects, and may indicate that future oil sands mining and extraction projects may not all go ahead with cogeneration units.

CHAPTER 5
SUMMARY

5.1 Summary and Reference Cases

In this Part of the report we have presented the Reference Cases for:

- Supply Costs
- Constrained Projection – Projection Reference Case
- Reference Case for Natural Gas and Emissions

Table 5.1 summarizes the supply cost results, for each of the oil sands recovery, extraction, and upgrading technologies analyzed.

Table 5.1
Supply Cost Summary

	Plant Gate Supply Cost (2007 $ / bbl)	Gas Price Sensitivity
CSS Cogeneration	35.95	37.18
CSS No Cogeneration	36.87	37.31
SAGD Cogeneration	34.36	35.78
SAGD No Cogeneration	33.81	34.74
Mining and Extraction	35.86	36.35
Mining, Extraction, and Upgrading	72.91	73.67
Standalone Upgrading	31.84	32.60
Standalone Upgrading (SAGD Bitumen)	71.84	N/A
Standalone Upgrading (Mining and Extraction Bitumen)	73.55	N/A

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APPENDIX A
PROJECT LIST

A.1 In Situ Projects

In Situ Projects

Athabasca - Cold Lake - Peace River

	Project Description			Status	Announced Start-up Date	Last Year	Announced Capacity (m3 / day)	Announced SCO Capacity (m3 / day), where applicable
CNRL				Type (2=Other, 1=SAGD, 0=CSS)				
	Kirby							
		1	Phase 1	Application	2011	2032	7,154	
Enerplus Resources				Type (2=Other, 1=SAGD, 0=CSS)				
	Kirby							
		1	Phase 1	Disclosure	2011	2041	1,590	
ConocoPhillips				Type (2=Other, 1=SAGD, 0=CSS)				
	Surmont							
		1	Phase 1	Operating	2007	2037	3,975	
		1	Phase 2	Approved	2009	2039	3,975	
		1	Phase 3	Approved	2011	2041	3,975	
		1	Phase 4	Approved	2014	2044	3,975	
Total (Deer Creek)				Type (2=Other, 1=SAGD, 0=CSS)				
	Joslyn Creek							
		1	Phase 1	Operating	2004	2034	159	
		1	Phase 2	Construction	2007	2037	1,590	
		1	Phase 3a	Disclosure	2009	2039	2,380	
		1	Phase 3b	Disclosure	2011	2041	3,970	

PetroCanada (Devon)				Type (2=Other, 1=SAGD, 0=CSS)				
	Dover							
		1	Existing Operations	Operating	2003	2033	222	
Devon				Type (2=Other, 1=SAGD, 0=CSS)				
	Jackfish							
		1	Phase 1	Construction	2008	2038	5,565	
		1	Phase 2	Application	2010	2040	5,565	
EnCana				Type (2=Other, 1=SAGD, 0=CSS)				
	Christina Lake							
		1	Existing Facilities (Year-end 2002)	Operating	2002	2032	954	
		1	Phase 2/3 Adjustments	Approved	2008	2038	1,908	
		1	Unidentified Expansion	Announced	2009	2039	14,308	
		1	Unidentified Expansion	Announced	2011	2041	7,949	
		1	Unidentified Expansion	Announced	2013	2043	14,308	
JACOS				Type (2=Other, 1=SAGD, 0=CSS)				
	Hangingstone							
		1	Existing Facilities (Year-end 2002)	Operating	1999	2029	1,590	
		1	Commercial project	Disclosure	2013	2043	7,950	
OPTI / Nexen				Type (2=Other, 1=SAGD, 0=CSS)				
	Long Lake							
		1	Existing Facilities (Year-end 2004)	Operating	2003	2033	400	
		1	Phase 1	Construction	2008	2038	11,447	9,295
		1	Phase 2	Application	2011	2041	11,447	9,295
		1	Phase 3	Application	2013	2043	11,447	9,295
		1	Phase 4	Announced	2014	2044	11,447	9,295
Petro-Canada				Type (2=Other, 1=SAGD, 0=CSS)				
	MacKay River							

		1	Existing Operations	Operating	2002	2032	4,770	
		1	Expansion	Application	2010	2040	6,359	
	Meadow Creek							
		1	Phase 1	Approved			6,359	
		1	Phase 2	Approved			6,359	
	Lewis							
		1	Phase 1	Disclosure			6,359	
Suncor				Type (2=Other, 1=SAGD, 0=CSS)				
	Firebag							
		1	Pilot	Operating	2000	2030	7	
		1	Phase 1	Operating	2004	2034	5,240	4,244
		1	Phase 2	Operating	2006	2036	5,560	4,504
		1	Cogeneration and Expansion	Construction	2007	2037	3,970	3,216
		1	Phase 3	Approved	2008	2038	5,560	4,504
		1	Phase 4	Approved	2009	2039	5,560	4,504
		1	Phase 5	Announced	2012	2042	7,950	6,440
		1	Phase 6	Announced	2013	2043	7,950	6,440
		1	Phase 7	Announced	2014	2044	7,950	6,440
		1	Phase 8	Announced	2015	2045	10,000	8,100
Petrobank (Orion)				Type (2=Other, 1=SAGD, 0=CSS)				
	Whitesands							
		1	Pilot	Operating	2006	2010	300	
		1	Unidentified Expansion	Speculative				
Husky				Type (2=Other, 1=SAGD, 0=CSS)				
	Sunrise							
		1	Phase1	Approved	2012	2042	7,950	
		1	Phase 2	Approved	2014	2044	7,950	

		1	Phase 3	Approved	2016	2046	7,950
		1	Phase 4	Approved	2018	2048	7,950
MEG				Type (2=Other, 1=SAGD, 0=CSS)			
	Christina Lake Regional Pilot						
		1	Pilot	Construction	2007	2037	480
		1	Commercial	Application	2008	2038	3,500
			Phase 2	Application	2008	2038	3,500
			Phase 2b	Application	2008	2038	5,564
			Phase 3	Disclosure	2011	2041	23,800
Encana				Type (2=Other, 1=SAGD, 0=CSS)			
	Brintell						
		1	Total	Operating	2003	2025	2,612
CNRL				Type (2=Other, 1=SAGD, 0=CSS)			
	Brintell						
		1	Total	Operating	2003	2025	393
EnCana				Type (2=Other, 1=SAGD, 0=CSS)			
	Borealis						
		1	Unidentified Expansion	Announced	2010	2040	5,246
		1	Unidentified Expansion	Announced	2011	2041	5,246
		1	Unidentified Expansion	Announced	2013	2043	5,246
Connacher Oil and Gas				Type (2=Other, 1=SAGD, 0=CSS)			
	Great Divide Oil Sands						
		1	Pod 1	Operating	2007	2037	1,590
	Algar						
		1	Phase 1	Application	2009	2039	1,600

KNOC				Type (2=Other, 1=SAGD, 0=CSS)				
	Blackgold							
		1	Phase 1	Announced	2010	2040	5,564	
Value Creation				Type (2=Other, 1=SAGD, 0=CSS)				
	Terre de Grace							
		1	Phase 1	Announced	2011	2041	6,359	5,532
		1	Phase 2	Announced	2015	2045	12,718	11,065
CNRL				Type (2=Other, 1=SAGD, 0=CSS)				
	Birch Mountain (Horizon In Situ)							
		1	Phase 1	Announced	2013	2043	4,770	
		1	Phase 2	Announced	2015	2045	4,770	
		1	Phase 3	Announced	2017	2047	4,770	
CNRL				Type (2=Other, 1=SAGD, 0=CSS)				
	Gregoire Lake							
		1	Phase 1	Announced	2016	2046	4,770	
		1	Phase 2	Announced	2018	2048	4,770	
		1	Phase 3	Announced	2020	2050	4,770	
		1	Phase 4	Announced	2023	2053	4,770	
Statoil				Type (2=Other, 1=SAGD, 0=CSS)				
	Kai Kos Dehseh							
		1	Phase 1	Application	2009	2039	1,600	
		1	Phase 2	Disclosure	2012	2042	11,000	
		1	Phase 3	Disclosure	2016	2046	22,000	
Value Creation				Type (2=Other, 1=SAGD, 0=CSS)				
	Halfway Creek							
		1	Phase 1	Announced	2009	2039	1,590	
Patch International								

	Ells River						
		1	Pilot	Announced	2010	2040	1,590
CNRL				Type (2=Other, 1=SAGD, 0=CSS)			
	Primrose & Wolf Lake Expansion						
		0	Existing Facilities (Year-end 2004)	Operating	1996	2040	9,000
		0	Primrose North	Operating	2006	2040	4,750
		0	Primrose East	Construction	2009	2040	4,750
CNRL				Type (2=Other, 1=SAGD, 0=CSS)			
	Lindberg						
		1	Existing Facilities	Operating	1985	2015	645
CNRL				Type (2=Other, 1=SAGD, 0=CSS)			
	Elk Point						
		1	Existing Facilities	Operating	1993	2023	134
EnCana				Type (2=Other, 1=SAGD, 0=CSS)			
	Foster Creek						
		1	Existing Facilities (Year-end 2004)	Operating	2003	2033	477
		1	Existing Facilities (Year-end 2005)	Operating	2005	2035	4,770
		1	Expansion (Year end 2006)	Operating	2007	2037	3,180
		1	Unidentified Expansion	Construction	2008	2038	5,564
		1	Unidentified Expansion	Announced	2009	2039	4,769
		1	Unidentified Expansion	Announced	2010	2040	4,769
CNRL				Type (2=Other, 1=SAGD, 0=CSS)			
	Primrose						
		1	Existing Facilities	Operating	1992	2022	182
Husky				Type (2=Other, 1=SAGD, 0=CSS)			

	Tucker						
		1	Phase 1	Operating	2007	2037	4,770
Imperial Oil				Type (2=Other, 1=SAGD, 0=CSS)			
	Cold Lake						
		0	Existing Facilities (Year-end 2005)	Operating	1985	2015	17,578
		0	Phases 11-13 Mahkeses	Operating	2003	2033	4,770
		0	Phases 14-16 Nabiye, Mahikan North	Approved	2008	2038	4,770
Other Operating Projects - Cold Lake				Type (2=Other, 1=SAGD, 0=CSS)			
	Petrovera - Lindberg						
		1		Operating	1990	2020	4
				Type (2=Other, 1=SAGD, 0=CSS)			
	Murphy - Lindberg						
		1		Operating	1991	2021	10
				Type (2=Other, 1=SAGD, 0=CSS)			
	ExxonMobil - Wolf Lake						
		1		Operating	1997	2027	0
Shell				Type (2=Other, 1=SAGD, 0=CSS)			
	Peace River Complex						
		2	Existing Facilities (Year-end 2002)	Operating	1975	2005	2,000
		2	Carmon Creek Phase 1	Application	2009	2039	8,000
		2	Carmon Creek Phase 2	Application	2012	2042	4,000
		2	Carmon Creek Phase 3	Application	2015	2045	4,000
			Total Capacity				

Penn West				Type (2=Other, 1=SAGD, 0=CSS)			
	Seal						
		2	Existing Facilities (2006)	Operating	2006	2036	572
		2	Carmon Creek Phase 1	Construction	2007	2037	700
		2	Carmon Creek Phase 2	Announced	2011	2041	1,908

A.2 Stand Alone Mine and Extraction Projects

Mining and Extraction Projects

Project Description			Status	Announced Start-up Date	Last Year	Announced Capacity (m3 / day)
Athabasca Oil Sands Project						
	Muskeg River Mine					
		Existing Facilities (Year-end 2002)	Operating	2002	2042	24,600
		Optimization/Expansion	Approved	2010	2050	18,350
	Jackpine Mine					
		Phase 1	Construction	2010	2032	31,800
		Phase 2	Application	2012	2049	15,900
Shell						
	Pierre River Mine					
		Phase 1	Application	2018	2058	31,800
Synenco						
	Northern Lights					
		Phase 1	Application	2010	2050	9,102
		Phase 2	Application	2012	2052	9,102
Total						
	Joslyn Mine					
		Phase 1 (North mine)	Application	2010	2050	7,950
		Phase 2 (North mine)	Application	2013	2053	7,950
		Phase 3 (South mine)	Announced	2016	2056	7,950
		Phase 4 (South mine)	Announced	2019	2059	7,950
Imperial Oil						
	Kearl Lake					
		Phase 1	Approved	2010	2050	15,900
		Phase 2	Approved	2012	2052	15,900
		Phase 3	Approved	2018	2058	15,900

PetroCanada / UTS / Teck						
	Fort Hills					
		Phase 1	Approved	2011	2051	50,000
		Phase 2/3	Approved	2014	2054	65,000

A.3 Stand Alone Upgraders

Stand Alone (Off-site) Upgraders

	Project Description		Status	Announced Start-up Date	Last Year	Announced SCO Capacity (m3 / day)
Suncor						
	Voyager Upgrader					
		Voyager Phase 1	Approved	2010	2050	20,188
		Voyager Phase 2	Approved	2012	2052	10,020
BA Energy						
	Heartland Standalone Upgrader					
		Phase 1	Construction	2008	2048	13,800
		Phase 2	Approved	2010	2050	13,800
		Phase 3	Approved	2012	2052	13,800
Statoil						
	Kai Kos Dehesh Upgrader					
		Phase 1	Disclosure	2011	2051	10,962
		Phase 2	Disclosure	2014	2054	19,140
Northwest Upgrading						
	Upgrading Only					
		Phase 1	Application	2010	2050	9,540
		Phase 2	Application	2012	2052	9,540
		Phase 3	Application	2014	2054	9,540

Peace River Oil						
	Bluesky Upgrader					
		Phase 1	Announced	2011	2051	6,758
		Phase 2	Announced	2013	2053	6,758
		Phase 3	Announced	2015	2055	3,379
		Phase 4	Announced	2017	2057	3,379
CNRL						
	In Situ Upgrader					
		Phase 1	Announced	2012	2052	19,871
		Phase 2	Announced	2015	2055	7,949
Total						
	Joslyn/Surmont Upgrader					
		Phase 1	Announced	2014	2054	15,898
		Phase 2	Announced	2017	2057	15,898
Synenco						
	Northern Lights Upgrader					
		Phase 1	Application	2010	2050	7,950
		Phase 2	Application	2012	2052	7,950
Petro-Canada / UTS						
	Sturgeon Upgrader					
		Phase 1	Application	2011	2051	22,130
		Phase 2/3	Application	2014	2054	23,472

Shell						
	Scotford Upgrader					
		Existing Facilities (Year-end 2002)	Operating	2002	2042	24,642
		Approved Expansion	Construction	2010	2050	21,462
		Expansion #1	Disclosure	2012	2052	15,898
		Expansion #2	Disclosure	2012	2052	15,898
		Expansion #3	Disclosure	2012	2052	15,898
		Expansion #4	Disclosure	2012	2052	15,898
		Upgrader #2 Phase 1	Construction	2013	2053	15,898
		Upgrader #2 Phase 2	Application	2015	2055	15,898
		Upgrader #2 Phase 3	Application	2017	2057	15,898
		Upgrader #2 Phase 4	Application	2019	2059	15,898
Husky						
	Lloydminster Expansion					
		Existing Facilities (Year-end 2002)	Operating	2000	2040	
		Debottlekneck	Construction	2007	2047	
		Expansion #1 (Alberta Bitumen Feedstock)	Announced	2010	2050	11,218
Petro-Canada						
	Strathcona Upgrader / Refinery Complex					
		Conversion	Construction	2008	2048	21,463

A.4 Integrated Mining and Extraction and Upgrader Projects

Integrated Mining and Extraction and Upgrading Projects

	Project Description		Status	Announced Start-up Date	Last Year	Announced SCO Capacity (m3 / day)
CNRL						
	Horizon					Bitumen
		Phase 1	Operating	2008	2048	18,123
		Phase 2	Approved	2009	2049	6,518
		Phase 3	Approved	2011	2051	12,401
		Phase 4	Announced	2015	2055	11,924
		Phase 5	Announced	2017	2057	18,283
Suncor						
		Base Mine	Operating	1967	2007	35,542
		Steepbank Debottleneck	Operating	2006	2046	3,220
		Millennium Debottleneck	Construction	2008	2048	2,962
		North Steepbank Extension	Approved	2010	2050	23,174
		Voyageur South	Application	2012	2052	15,453
Syncrude						
	Mildred Lake & Aurora					
		Existing Facilities (Year-end 2005)	Operating	1978	2018	39,100
		Stage 3 Expansion	Operating	2006	2046	15,900
		Stage 3 Debottleneck	Construction	2012	2052	6,289
		Stage 4 Expansion	Announced	2017	2057	13,672

APPENDIX B
OIL SANDS REGULATION, TAXES AND ROYALTIES

B.1 Regulatory Structure

The regulatory process for electricity generators in Alberta has been designed so that it is conducive to the development of a competitive market with many producers. The Alberta Electric Act allows Independent Power Producers (IPP), including cogenerators, to compete on an equal basis with the utility generators to supply to the grid on a non-discriminatory basis. There is no longer a requirement for the regulator to approve new generating (or cogeneration) units on the basis of province-wide need for capacity. A utility or IPP may build a new unit on the basis of forecast revenue at the pool price. Even though competition controls the cost of new generation, regulation is still needed in many other areas of the electric industry:

- Operation of transmission systems is monitored to ensure that no conflict of interest occurs among generators, distributors, and transmission owners who are linked corporately.
- The Transmission Administrator is responsible for tariffs which recover system access costs from distributors and generators. Tariffs are subject to regulatory approval.
- Contracts between a utility generator and its affiliated distribution company are reviewed to ensure they are in the best interest of customers.
- Environmental assessments of any generating unit are subject to regulatory approval.

Regulatory approval to export electricity from Alberta is not required; there are, however, other regulatory bodies with certain restrictions. Before exports can occur, the National Energy Board Act requires the electricity export application to be approved. The NEB takes into account the effects of the electricity exports on all provinces, not just the effects on the exporting province. The Board must also be assured that the export applicant has provided the same terms and conditions to potential local purchasers. In addition, the Board also assesses any impact of electricity exports on the environment.[21]

For electricity exports into the US, applicants have to deal with US federal and state authorities, in particular, the Federal Energy Regulatory Commission (FERC).[22] Some Canadian entities have been granted wholesale trader status by the FERC by satisfying the reciprocity requirements of open access under the FERC Order 888. To further facilitate Canadian export access to US

[21] National Energy Board, Energy Market Assessment "Canadian Electricity Trends and Issues", May 2001. *www.neb-one-gc.ca*

[22] AESO. *Facilitating Major New Generation in Alberta, An Overview of the Transmission Infrastructure Requirements*. August 17, 2001. www.aeso.ca/files/Facilitating_Major_New_Generation_in_Alberta.pdf

markets, as well as access to US supplies by Canadians, transmission companies in several provinces are considering memberships in Regional Transmission Organizations (RTOs).[23]

Canadian entities are not subject to the FERC regulation but, given the integrated nature of the North American transmission system, it appears that their involvement in the RTOs would be potentially beneficial to all market participants, provided proper approaches for jointly overseeing cross-border RTOs are adopted.

Directionally, RTOs could facilitate increased north-south trade and a greater integration of Canadian and US electricity markets. To the extent that Canadian competitiveness can be maintained, higher export revenues would result.

B.2 Fiscal Classification of Cogeneration

The risks and large costs of oil sands projects, particularly in the early years, have been recognized by the tax and royalty systems. Generous write-offs for property and development expenses were available for oil sands projects and lower royalty rates during the early years of production are still available. Furthermore, in reference to cogeneration, there are tax incentives to initiate the development of efficient energy production. These provisions, as included in the supply cost calculations, are described below.

Oil sands operators with on-site cogeneration are faced with the decision of classifying cogeneration units as either *within the fence* or *outside the fence*. In both cases the cogeneration unit is operated by the same corporate entity as the oil sands project, but the classification of the cogeneration investments and revenues affect the project's tax and royalty structure.

Cogeneration that is classified as *within the fence* falls under the oil sands Capital Cost Allowance (CCA) Class 41(a) with the accelerated 100 percent write-off rate, but any revenues generated through the sale of excess electricity are subject to the royalty rate charged on the project's revenues. If categorized as *outside the fence*, cogeneration capital is classified under Class 43.1, receiving a 30 percent write-off rate and avoiding any royalty charges on electricity revenues.

B.3 Taxes

Oil sands project investments are classified as CCA Class 41/41(a) eligible investments.[24] This provides for a 100 percent per annum write-off, subject to the half-year rule in the year the investments are made. Cogeneration investments *within the fence* are also eligible for Class 41/41(a) classification, thus decreasing taxable income for the oil sands project.[25] In 2007, the

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[23] Observations on Canadian Electricity Trends and Issues http://www.electricity-today.com/et/issue0901/i09_trends.htm

[24] Appendix B.2 in Part II.

[25] The rules governing taxation of oil sands projects are found in the Federal Income Tax Act. For Capital Cost Allowance (CCA) purposes, all oil sands assets are included in Class 41 of the Federal Income Tax Act. See http://www.energy.gov.ab.ca/1911.asp, August 14, 2005. Class 41 includes all resource

Federal Government initiated a phasing out of this 100 percent per annum write-off. Starting in 2012 the write-off is reduced by 10 percent each year, until it is no longer in force. CERI's modeling reflects this.

Cogeneration classified as *outside the fence* or separate from the oil sands project is eligible for Class 43.1 CCA classification. Class 43.1 in Schedule II of the *Income Tax Act* provides taxpayers with an accelerated write-off of equipment that is designed to produce energy in a more efficient manner.[26] Without the accelerated write-off these assets would be depreciated at annual rates of 4 to 20 percent. The accelerated write-off of 30 percent per annum on a declining balance basis is lower than the Class 41(a) write-off for oil sands, but electricity revenues are not included in the calculation of royalty payments. Therefore, when considering the cogeneration unit as a separate entity from the oil sands project, or *outside the fence*, income taxes and royalties need to be calculated differently.

B.4 Royalties

Expenses arising from services that are deemed to be basic services to extract bitumen, such as steam and electricity, are applicable for royalty calculations. Steam is considered a basic service, and costs associated with steam production are royalty applicable. The cost of service of steam is deducted from revenues, lowering net revenues and royalties payable. Electricity is also a basic service, but the royalty treatment of expenses arising from electricity generation depends on their classification as either *within the fence* or *outside the fence*.

- If the cogeneration unit is *within the fence* the electricity and steam are valued at their cost of service.[27]
- If the cogeneration unit is *outside the royalty fence*, the steam is valued at its cost of service but the electricity is considered to be a non-arms length service and is valued at fair market value. It is as if the oil sands owner is selling electricity back to itself from its own outside

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extraction assets acquired after 1987. It also includes electrical generating equipment for mines, equipment used in resource exploration and heavy crude oil processing, natural gas processing plants, and drilling vessels for oil and gas. The CCA rate is 25 percent on a declining balance basis. There is also an exception, known as Class 41(a), with the special CCA rate of 100 percent for new mine and in-situ projects as well as mine expansion assets, as defined in the Act, but it is limited to the amount of income earned from the mine plus 5 percent. In these cases, no corporate income tax is paid on the income from the mine until all capital expenses are written off. See http://www.oag-bvg.gc.ca/domino/reports.nsf/html/c003ac_e.html, August 14, 2005.

[26] Government of Canada. 1998. *Tax Incentives for Business Investments in Energy Conservation and Renewable Energy*. 26 August 2005 <http://www2.nrcan.gc.ca/es/erb/CMFiles/tax_incentive172OEW-10032004-2257.pdf>

[27] The value is the amount deducted from revenue to get a royalty applicable net revenue amount. For COS, assume that the amount charged of electricity, if any sales, would be the COS amount.

generating facility. The fair market value is an average of market electricity prices,[28] without a transmission charge.

Cogeneration costs are relatively minimal in the overall costs of an oil sands project, and listing the cogeneration unit as *within the fence* could be easier administratively. However, when producing a large amount of electricity this would imply paying royalties on the excess electricity sold.

Revenue accrued from excess electricity sales is taxable, but not always royalty-applicable.

- If the unit is classified as *within the fence*, excess electricity sales are added to the revenue and increase the royalties payable.
- If the unit is classified as *outside the fence*, excess electricity sales are not included in the revenue and the oil sands royalty payable is not affected by earnings from selling electricity.

If it is expected that a substantial amount of excess electricity generation will be sold to the grid, it appears to be beneficial to classify the cogeneration unit as *outside the fence* so that the electricity sales revenue does not increase the royalties payable.[29] One exception is if the excess generation might be used internally as expansion occurs, and thus no electricity sales revenue will be acquired, then it might be more advantageous to classify the cogeneration project as *within the fence*. The classification will be chosen by the operator by comparing the tax saving to the potential royalty payments on electricity revenues.[30]

In 2007, the Alberta Government announced their plans to change the oil sands royalties. While the new Royalty Framework, as proposed by the Premier in 2007, has not received Royal Assent, CERI will provide a sensitivity analysis of our supply costs to reflect the Framework. This will be further discussed in the sensitivity analysis portion of the supply costs.

B.5 Expense Allocation

For cost of service determinations, the capital, operating and other annual non-fuel related costs relating to the cogeneration plants must be allocated between steam and electricity. The critical point is where in the process hot air is captured.

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[28] A monthly FMV includes all/some of these market prices: average pool price, average day-ahead price, balance of month, prompt month, prompt month+1, prompt quarter, prompt quarter2, rest of year, and next calendar year.

[29] This benefit may be offset if the electricity FMV is less than its COS and the cogeneration unit is *within the fence*. The benefit depends on the amount and price of excess generation.

[30] Classifications for royalty calculations are not tied to tax classification. That is, the royalty ring-fence has nothing to do with the federal tax ring-fence. For this study, cogeneration projects, for ease of calculation, are classified as within the fence, regardless of excess electricity sales.

- Those costs incurred upstream of where hot air is captured for the production of steam by the HRSG are to be allocated to electricity.[31]

- Those costs incurred at that point and downstream of where hot air is captured for the production of steam are to be allocated to steam.[32]

Fuel costs are also allocated between steam and electricity, since both are products of the input fuel. Fuel allocations in cost of service determinations depend on whether there is a fair market value for electricity. If there is a fair market value (i.e., the cogeneration unit is *outside the fence*), then steam and electricity will be charged at the lesser of:

- Electricity at fair market value and steam costs at cost of service with fuel charged to steam based on a HRSG operating at an assumed thermal efficiency of 85 percent,

- Electricity at actual amount charged to the project and steam at cost of service in accordance with the fuel charged to steam formula.[33]

If there is no fair market value, or the cogeneration project is deemed to be *within the fence*, the steam and electricity will be charged at the lesser of:

- Electricity at cost of service with fuel charged to power equal to all fuel (GT and Duct) minus fuel charged to steam, and steam at cost of service with fuel charged to steam at a thermal efficiency of 85 percent,

- Electricity at actual amount charged to the project and steam cost at cost of service with fuel charged to steam in accordance with the fuel charged to steam formula.

In summary, if there is excess electricity that will be sold, the cogeneration unit is classified as outside the fence, and if there are no electricity sales (or relatively small sales compared to cost of service versus fair market value assessments) the unit would be classified as within the fence.

[31] For example, the GT and generator are allocated to electricity, the HRSG is not.

[32] The HRSG, for example, is allocated to steam, but not the gas turbine and generator.

[33] See Page 10 of the Draft Guideline 3.5.1.6: Valuation of Steam and Electricity from Non-Arms Length Facilities, as per the Electricity COS FMV Task Force, Oil Sands Royalty Steering Committee. Special thanks to Christopher Holly for additional comments.

B.6 Classification Summary

For a cogeneration project classified as *within the fence*:

- Accelerated tax write-off as per Class 41/41(a).
- Royalty write-offs for electricity costs valued at cost of service.
- Electricity sales revenue added to royalty applicable revenue.

For a cogeneration project classified as *outside the fence*:

- Accelerated tax write-off as per Class 43.1.
- Royalty write-offs for electricity costs valued at fair market value.
- Electricity sales revenue not applied to royalty calculations.

In both cases:

- Royalty write-offs for steam costs valued at cost of service.
- Electricity sales subject to income tax.

APPENDIX C
PROCESSES FOR UPGRADING

As a severe method of thermal cracking, the coking process involves sending bitumen to the coker's reactors where high temperatures cause the long bitumen molecules to thermally crack. Coking is used to upgrade heavy residuals into lighter products or distillates. The residue is a form of carbon called "coke." The two most common processes in oil sands operations are delayed coking and continuous (contact or fluid) coking. Suncor uses delayed coking while Syncrude uses fluid coking.

In delayed coking, the heated charge (typically residuum from atmospheric or vacuum distillation towers) is transferred to large coke drums that provide the long residence time needed to allow the cracking reactions to proceed to completion. After the coke reaches a predetermined level in one drum, the feed is diverted to another drum to maintain continuous operations. The full drum is steamed to strip out uncracked hydrocarbons, cooled by water injection, and decoked by mechanical or hydraulic methods. Continuous (contact or fluid) coking is a moving-bed process that operates at temperatures higher than delayed coking. In continuous coking, thermal cracking occurs by using heat transferred from hot, recycled coke particles to feedstock in a radial mixer, called a reactor.

Produced coke is used as a fuel source for the coker burners (fluid coking at Syncrude) as well as for other heat requirements (Suncor power plant). Excess coke is stockpiled or sold for industrial applications. Future operations will likely gasify coke to produce fuel and hydrogen feedstock; to what degree this will happen, depends on numerous factors.

The Scotford Upgrader of the Athabasca Oil Sands Project (AOSP) uses hydro-conversion processes rather than coking. The hydro-conversion technology provides a greater yield of high quality synthetic crude oil compared to coking techniques. Hydrocracking is a two-stage process combining catalytic cracking and hydrogenation, wherein heavier hydrocarbons are cracked in the presence of hydrogen to produce more desirable products. The process employs high pressure, high temperature, a catalyst, and hydrogen. The hydrocracking process largely depends on the nature of the feedstock and the relative rates of the two competing reactions, hydrogenation and cracking. Heavy aromatic feedstock is converted into lighter products under a wide range of very high pressures (1,000-2,000 psi) and high temperatures (400-815°C) in the presence of hydrogen and special catalysts. When the feedstock has a high paraffinic content, the primary function of hydrogen is to prevent the formation of polycyclic aromatic compounds. Another important role of hydrogen in the hydrocracking process is to reduce tar formation and prevent a buildup of coke on the catalyst.

Catalytic hydrotreating is a process that is used within all of the industries' upgraders to remove about 90 percent of contaminants such as nitrogen, sulphur, oxygen, and metals from liquid petroleum fractions. Hydrotreating for sulphur removal is called hydrodesulphurization. In a typical catalytic hydrodesulphurization unit, the feedstock is mixed with hydrogen, preheated in a fired heater (315-425°C) and then charged under pressure (up to 1,000 psi) through a fixed-bed catalytic reactor. Hydrotreating converts sulphur and nitrogen compounds present in the feedstock to hydrogen sulphide and ammonia.

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