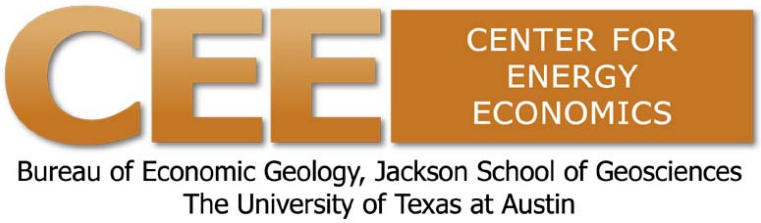

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OVERVIEW OF THE ALBERTA OIL SANDS

A Briefing Paper prepared

By the

Center *for* **Energy Economics**

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www.beg.utexas.edu/energyecon

Spring 2006

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EXECUTIVE SUMMARY

The Alberta Oil Sands are fast becoming one of the main areas of significant oil related investment in the world. This vast resource has little if any geological risk associated with it. However, technical and long run production cost uncertainty have still to be resolved, especially in the case of non-minable resources which encompass almost 90% of the oil sands.

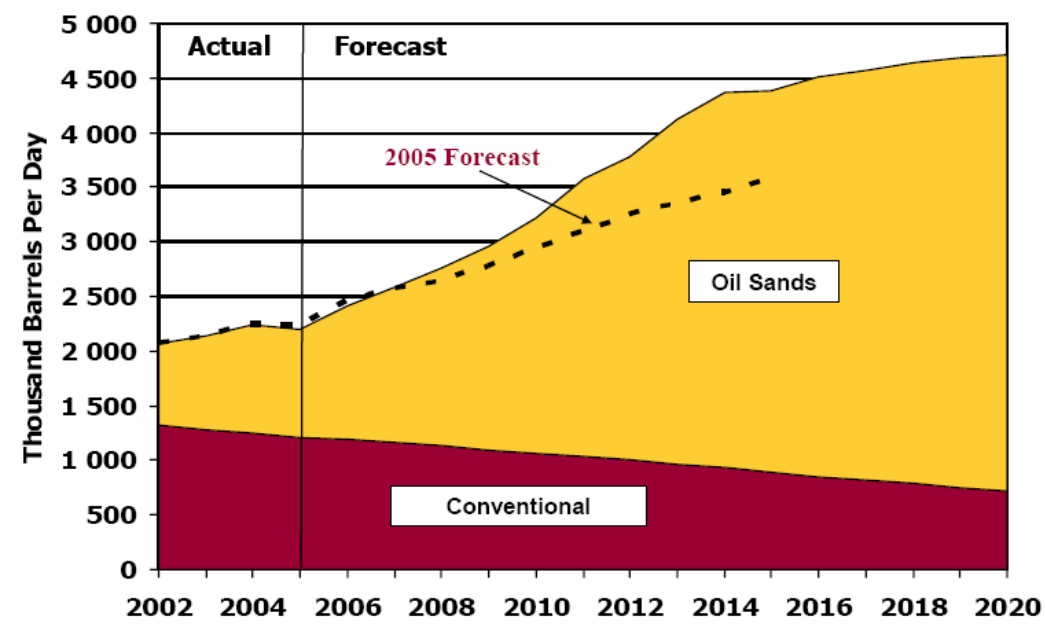
Novel technologies and the existence of economies of scale have made the Alberta Oil Sands an economically viable resource. Attractive fiscal terms have made the Alberta Oil Sands a resource where large scale investments are taking place. This despite the high upfront capital costs associated with oil sands production.

Oil Sands production is slated to overtake conventional oil production in Canada and will continue to grow at a pace that will test the availability of ancillary services for years to come.

The delivery of Oil Sands' production to markets requires investment not only in production but significant investments in downstream components such as upgrading units in order to guarantee an outlet for the production. In most cases, much like in the U.S. Gulf Coast, downstream bottlenecks limit markets for heavy oils. The Canadian National Energy Board estimates that integrated ventures based on the exploitation of the Alberta Oil Sands are economically viable at oil prices equivalent to WTI between $30 and $35 per barrel[1].

[1] Canada's Oil Sands: Opportunities and Challenges to 2015 – An Update. National Energy Board (June 2006)

Figure 1 Conventional versus Oil Sands Production[9]



ALBERTA OIL SANDS: A VAST RESOURCE

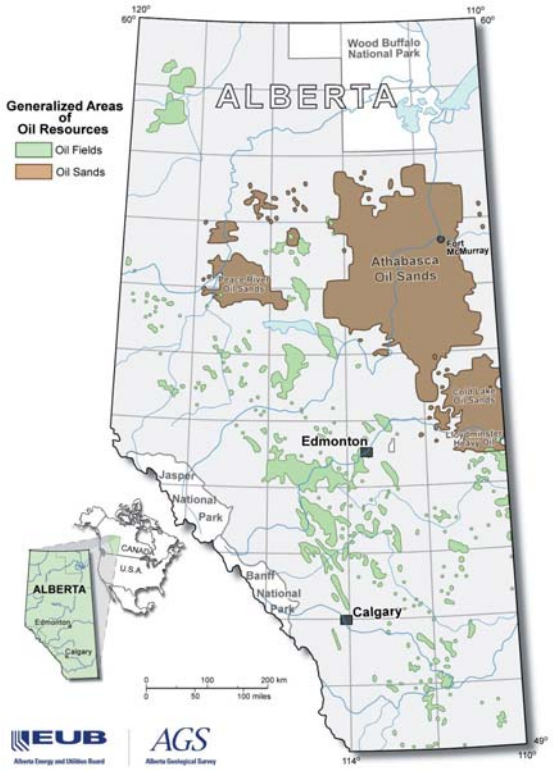
The Alberta Oil Sands can be found in an area of almost 150 thousand square kilometres. Geographically the deposits are in three regions: Athabasca (near Fort McMurray), Cold Lake (near Lloydminster) and Peace River (west of the Athabasca Oil Sands). Estimates of the original resource reach 1.7 trillion barrels in place. Not all is economically viable to be produced or in production today. However, such a large resource can generate large reserves depending on market conditions and technology. The sheer size of the resource creates an extremely attractive opportunity for investment.

The main characteristic of parts of the deposit is that they are shallow. In other words, the overburden (or soil that is between the deposit and the surface) is in some places limited to 75 meters. The resource that is estimated to be readily accessible via strip mining is nearly 10% of the total. The rest could eventually be produced using conventional oil production technology or in-situ as it is referred to in the Alberta Oil Sands context. In comparison, the Orinoco Oil Belt in Venezuela is estimated to be 1.2 trillion barrels where the minable fraction has not been determined and only in-situ production has been pursued. The main difference between the two

resources is the temperature of the heavy oil in the reservoir, which is of the order of 20 to 40 C. This difference results may seem small but in terms of viscosity of the heavy oil it is extremely important. The ratio of viscosities is nearly two orders of magnitude for the shallower Alberta oil sands. This reduces well production accordingly.

The reservoirs are unconsolidated sands where the sand, the oil and water are present. When the oil flows, it drags sand along with it due to its high viscosity. In the case of mining operations, the oil is shovelled jointly with the sand.

Figure 2 Geographic Distribution of the Alberta Oil Sands[2]



Production Strategies

The Alberta oil sands have been historically associated with mining operations where after removing the overburden, conventional massive mining operations are pursued. Over the past several decades, much effort

[2] Source: Alberta Energy Utilities Board

has been placed in optimizing the process for removing the overburden, mining the oil sand, transporting the oil sand to the sand separating process, the sand and diluent separation processes and the eventual sand disposal. Each one of these sub-processes has been tackled with brute force in the pursuit of economies of scale. For example, power shovels and dump trucks used for transportation have increased to in capacity 100 and 400 tons respectively.

Figure 3 Typical 100 ton power shovel and 400 ton dump truck in use in the Alberta Oil Sands[3]

Figure 4 Transport of oil sands to initial processing facility[4]

[3] Source: Martin Kaste, NPR.

[4] Source: San Francisco Chronicle, Brant Ward.

In the case of non-mining production, or in-situ, the temperature of the reservoir is a key variable. As mentioned above, the resulting viscosity of the crude oil in the reservoir is greatly affected by the temperature. In cases where the reservoir temperature is sufficiently high, primary production can be pursued. This is the case in the Orinoco oil belt and in some parts of the Alberta oil sands. Now given that the viscous heavy oil is mixed in with the unconsolidated sands, much of the sands would tend to flow to the wells. Recent studies estimate that if the sand is allowed to flow into the wells[5], increased production rates can be achieved and higher resulting recovery factors obtained, up to 10% even under the primary production conditions.

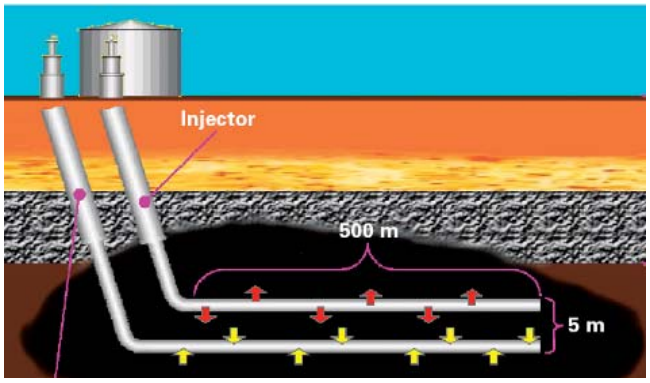
Primary production only applies to only a fraction of the resource. Advances in in-situ production will likely involve some sort of thermal stimulation such as steam injection (cyclic or continuous). Much experience exists in cyclic thermal injection projects. Cyclic injection increases the overall recovery factor to about 20 to 25%. This however is at an increased cost of anywhere between $3 to $12 per barrel produced for the thermal stimulation and the separation of the produced water.

Continuous steam injection usually follows cyclic steam injection given that it can use the infrastructure used during cyclic stimulation. Continuous steam injection could also be used as part of the original exploitation scheme. Advances in technology, be it well construction, well materials and well instrumentation, have generated more advanced continuous steam injection approaches. One such approach is Steam Assisted Gravity Drainage (SAGD) in which a pair of horizontal wells is used to inject steam continuously and to produce oil continuously. Over 100 well pairs have been built and put into operation and results indicate that it may be an attractive production strategy. However, long run marginal production costs have not been determined nor estimated (at least not available in the public domain). Recovery factors are estimated to be much greater with values up to 60%.

[5] This technique is referred to as Cold Heavy Oil Production with Sand or CHOPS.

More sophisticated follow-up techniques are under consideration where staggered wells, infill vertical and horizontal wells are considered.

Figure 5 Schematic of typical SAGD horizontal well pair[6]



Another technique that used is that of the injection of diluent into the reservoir to reduce viscosity. One process involves the injection of diluent vapors in order to heat the heavy oil and also reduce its viscosity via the incorporation of the solvent into the heavy oil matrix. One such technique is commonly called VAPEX. VAPEX has shown interesting results in laboratory and core experiments but has not been tested at the commercial scale.

Finally, in-situ upgrading and in-situ combustion are processes that could and will likely dramatically change the way heavy oil is produced in the future. In-Situ upgrading techniques seek to use reservoirs as process units in which heavy crude upgrading takes place. Physical separation processes such as solvent extraction have been shown to produce crude of vastly improved properties without the capital expenses that are required with surface upgrading. In-situ combustion on the other hand provides an opportunity to not only upgrade the heavy oil but to also increase recovery factors greatly. Many tests have been performed in the past and control and instrumentation technology may be reaching the point where in-situ combustion could become a continuous and effective upgrading process. In recent past, laboratory and core tests have been performed to showcase and demonstrate new processes which involve combinations of vertical and horizontal wells

[6] Source: JACOS Limited

(e.g. Toe to Heel Air Injection or THAI). Field tests are under construction and should create great excitement if they prove successful in upgrading heavy oil in a controlled and safe manner.

AN ATTRACTIVE FISCAL REGIME: THE KEY TO THE SUCCESSFUL DEVELOPMENT OF A LOWER VALUE AND CAPITAL INTENSIVE RESOURCE

One mechanism that a resource owner can use to make investment opportunities attractive, especially in this case of high upfront capital investments, is that of royalty relief until the projects are paid out. The royalty relief is reflected in a rate of only 1% during the payout period. Afterwards, the royalty rate is increased to 25%. This fiscal regime allows for the rapid payout of investments and thus reducing the overall risk of the projects. The payout includes a return allowance at the long term bond rate. This regime was also used in the original fiscal terms for the development of the Orinoco Oil Belt in Venezuela. The regime in Venezuela has changed to reflect a 33.3% effective royalty rates, which in comparison is similar to the rate effective after the payout period in Alberta.

One interesting feature of the fiscal regime is that if the scope is changed, in other words, if the project production target is increased and new investments are made, the project payout period is extended and the 1% royalty is maintained. This is consistent with the constant expansion of projects in the region.

PRODUCTION HISTORY

Though the existence of the oil sands in Alberta has been known since the 19th century, commercial production only commenced in 1967 with the original Canadian Oil Sands project (now SUNCOR). Two other significant mining projects have followed, the Syncrude project which started operation in 1977 and the Albian Sands project which started operation in 2003. As can be seen in Table 1, increases in production of the oil sands have been associated with increases in upgrading capacity.

SUNCOR projects currently have a production capacity of the order of 225,000 barrels per day, mostly from mining operations. On the margin,

SUNCOR is experimenting with in-situ production techniques at production rates of 15,000 barrels per day. Regulatory applications indicate that SUNCOR is targeting production of the order of 500,000 barrels per day by 2012.

Similarly, Syncrude has a production/processing capacity of 235,000 barrels per day of synthetic crude oil (blend). Syncrude incorporates novel transportation technology for the oil sand where a froth is pipelined to the upgrading facility. Planned expansions for the Syncrude projects would take synthetic crude oil capacity to 350,000 barrels per day by year's end.

The newest venture, the Athabasca Oil Sands project is a joint venture between Shell Canada, Chevron Canada Resources and Western Oil Sands. It has rapidly ramped production to rates above 150,000 barrels per day and is considering plans to take production up to rates between 500,000 to 600,000 barrels per day in the coming decade.

There are many smaller ventures with current production rates below 50,000 barrels per day. However, most of these have plans to rapidly expand production once there in-situ production pilots achieve their expected results.

Table 1 Oil Sands Statistics 1996-2004[7]

Oil Sands:		**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
Capital Spending ($ billions)		0.0	1.9	1.5	2.4	4.2	5.9	6.7	5.0	6.2
		96/97	97/98	98/99	99/2000	2000/'01	2001/'02	2002/'03	2003/'04	2004/'05
Payments to province ($ billions) Royalties, Fiscal year		0.2	0.1	0.4	0.8	0.7	0.2	0.1	0.2	0.7
Reserves at year-end										
Mining - Integrated Synthetic (million barrels)		-	2,346	2,847	5,034	5,011	4,919	4,881	5,213	5,294
Raw In-situ Bitumen (million barrels)		-	1,446	1,388	1,561	1,805	1,820	2,024	2,032	2,082
Production										
Mining - Integrated Synthetic (thousands barrels/d)		0	290	308	324	320	349	441	429	465
Bitumen (thousands barrels/d)*		0	238	282	244	289	310	303	426	532

[7] Source: Canadian Association of Petroleum Producers, data in Canadian $.

Upgrader Capacity (Thousand barrels/d)		339	405	405	415	415	578	578	733	733
Industry Revenues ($ billions)		4.0	4.0	3.1	4.9	8.0	6.9	9.3	11.2	14.9

PLANNED PROJECTS

Canadian production was estimated at 2.5 million barrels per day in 2005. Many projects have been announced, some have moved forward with some of regulatory approvals and some of those have commenced the process for capital expenditures. Consensus estimates peg Canadian production at slightly more than 4.5 million barrels per day in 10 years. The Canadian Association of Petroleum Producers' (CAPP) forecast shows a monotonically increasing level of production from the Alberta oil sands. As mentioned above, both mining and in-situ production strategies are followed. The CAPP estimates that over the coming decade, growth in production following both strategies will be comparable. The resource base associated with in-situ production strategies is much greater and should eventually overtake mining operations once technologies are validated and used on a larger scale.

Much activity surrounds the oil sands in the present. As can be seen starting on page 19, many projects have been announced. It should become clear to the reader that not all of the announced projects will actually be built. Some will not receive the appropriate financing, and some will not be pursued within the portfolio of investments under consideration. In addition, new projects will be considered and may displace projects under development today. As will be seen below, oil sand production projects will likely take place only if associated investments in upgrading or processing is made. This creates a direct link between upstream and downstream investments. Each one mitigates risks for each other and thus should be considered in together. Downstream investments are in the order of $1 billion to upgrade 100 thousand barrels per day of oil sands production. This added to the upstream investments, which range anywhere from $1.5 to $3.5 billion, result in total capital investments of around $2.5 to $4.5 billion. The expected increase in production volumes, of the order of 3 million barrels per

day of additional production, requires capital investments of the order of $100 billion dollars. Interestingly enough, much interest exists despite the high upfront capital expenditures. This is likely a consequence of less attractive fiscal regimes in other regions and other risks that those investments involve.

Many of the current construction projects involve initial attempts to increase production via steam injection in SAGD configurations. These are targeting initial production rates between 3,000 to 10,000 barrels per day with capacity to expand as the technology is optimized.

The office of Alberta Economic Development tracks investment in oil sands projects in Alberta. Based on their evaluation of the likelihood of the investment, the office generates a time series of the investments which is presented in Figure 6. To reflect the likelihood of investment, different degrees of discount are applied to projects, ranging from 0% to projects that are under construction to 75% to projects that have commenced the project's regulatory approval process. Most of the announced capital investment will take place in the coming years as is expected and as new projects are announced, the peak in investment will move into the future. The main capital investments are currently for projects in the Fort McMurray area associated with mining and upgrading operations. In-situ investments still are small by comparison given that they mostly entail pilot programs. In-situ investments should eventually overtake mining investments once uncertainty regarding production rates and costs is resolved. However, production from mining operations will be greater for the foreseeable future given that cumulative investments in mining operations are clearly greater than those for in-situ production. Figure 7 shows that within the 2005 to 2015 window, production from mining operation still remains the dominant form of production from the oil sands.

Figure 6 Projected Capital Investments[8]

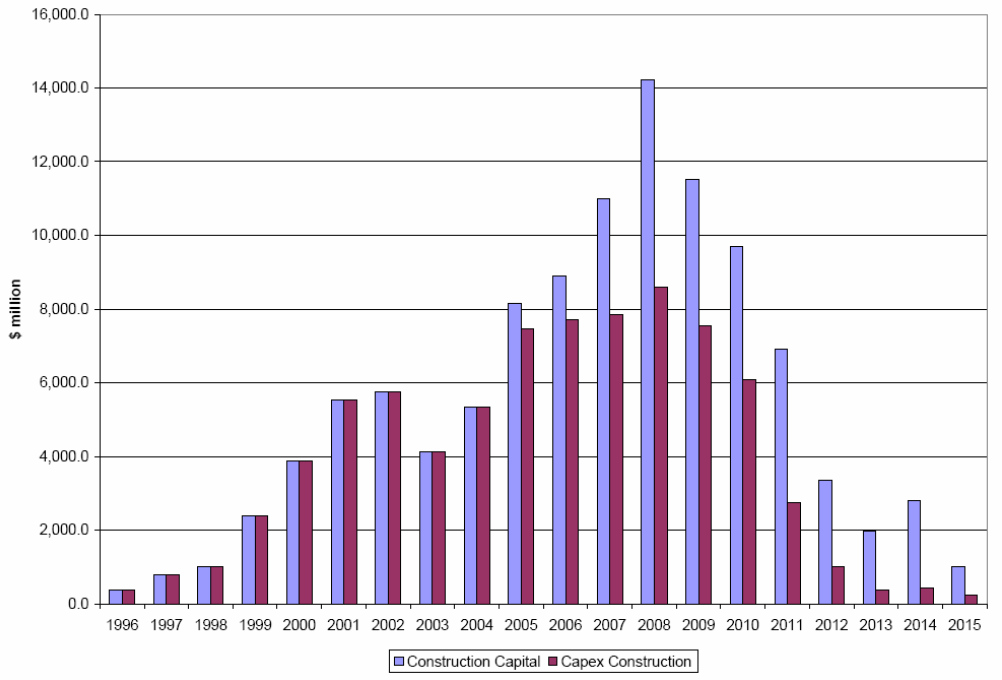
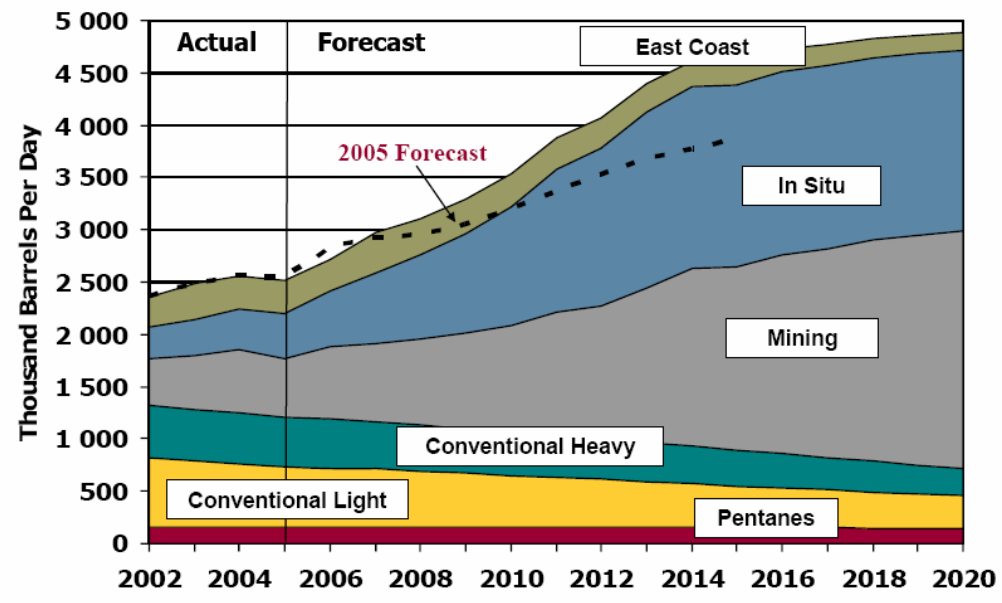


Figure 7 Future Canadian Oil Production[9]



[8] Source: Alberta Economic Development

[9] Source: Canadian Association of Petroleum Producers: Canadian Crude Oil Production and Supply Forecast 2006-2020

Limitations to Growth in Supply

The extremely large growth rate for the production of the oil sands in Alberta is putting pressure on many of the ancillary and core services and technologies that are required. In addition to competing with other upstream investment opportunities for capital, the main limitations for growth are:

1. Lack of human resources: much like the human resource crisis that is envisioned in the coming years for the hydrocarbon industry as a whole, the lack of availability of qualified personnel is already being observed in the oil sands producing regions. Upward pressures on salaries are already observed as a means to attract talent from other producing regions of the world. With this in mind, significant streamlining of immigration processes has been pursued and is allowing the incorporation of foreign talent to the productive activities in Alberta. Other alternatives such as training have longer horizons for generating qualified human resources.
2. Availability of natural gas: the production, handling and refining of the hydrocarbons produced from the oil sands is highly energy intensive. Historically, this energy is produced from the combustion of natural gas which was readily available at moderate prices. Residential and industrial demand, both domestic in Canada and in the U.S., generates pressure on the price of natural gas available for the exploitation and refining of the oil sands. Business as usual would require significant increases in the utilization of natural gas for the production of the oil sands. One of the possible new supplies of natural gas would be from the Alaska North Slope and/or the Mackenzie Valley pipelines. The transfer price for these natural gas supplies would likely make oil sands production costs higher than they are today. Other alternatives for generating heat will need to be explored in order to meet the increased demand. Many alternatives exist in order to generate heat. The most obvious would be to use part of the heavy oil production as a source of heat. The heavy oil has a high sulfur and heavy metal content and thus would require high capital investments for the

environmentally acceptable generation of heat (scrubbers for SO2 emission mitigation, special handling of ashes with high nickel and vanadium content, selective catalytic reducers for the mitigation of NOx emissions to name a few). Another solution is to generate heat with nuclear reactors. This alternative is attractive since CO2 emissions would be avoided. Nuclear energy would be used as a means to produce energy (hydrocarbons from the oil sands) for the transportation sector, something that cannot be done directly.

3. Markets for oil sands' hydrocarbons: the viscous and heavy hydrocarbons produced from the oil sands require special handling and refineries for their processing. These refineries are in short availability and thus are used to capacity in most cases given that growth in heavy oil production is outpacing refinery expansion or construction. A similar situation is observed in the U.S. Gulf Coast where heavy crude from Mexico (Maya crude) and Venezuela (e.g. Merey Crude) saturate the market to the point that there is a significant oversupply. A direct measure of this oversupply is the discount that heavy crude commands, which in some cases can reach $15 per barrel despite the fact that the differential cost in its processing can be an order of magnitude lower. With the availability of pipeline infrastructure from Canada to the Gulf Coast, the portfolio of refineries that can process Alberta heavy crude is increased and will likely put downward pressure on the realization prices for Mexican and Venezuelan supplies to the Gulf coast. Much like the development of the Venezuelan oil sands, or additional Mexican heavy oil, new volumes of crude oil will require the development of upgrading units that will bridge the gap between heavy crude and lighter crude. These upgrading units can be standalone generating synthetic crude as their output or part of refineries so that the refineries receive the heavy oil as input and generate final products as outputs. The bottlenecks in processing create a constraint in investments, requiring downstream investments to be considered in tandem with the upstream. If the downstream

component is not included, increased competition for access to refineries will generate higher discounts for the heavy oil.

4. The increased demand and increased prices have generated a period of significant capital investment. This increase in capital investment is taking place all over the world, creating competition for resources such as steel, manufacturing facilities such as pipeline equipment, drilling rigs to name a few. Prices in steel and other materials have shown a steady increase in recent times. Continued price increases in these areas could result in postponement of investments or lower profitability.

5. As mentioned above, in-situ associated resources are much greater than those associated with mining. These resources can only be exploited economically if all the related technologies are optimized and put into use. Most of the continuous steam injection technologies have not been widely used and the associated long run marginal costs are not known. The behavior of the production in time is also unknown and thus production uncertainty can become a problem.

6. Availability of diluents: the viscosity of the hydrocarbons produced from the oil sands is too great to allow for their transportation to markets. In most cases, a diluent is added to reduce the viscosity of the mixture to levels which allows for pipeline transportation. Diluents need to be delivered to the production areas in order to be added to the heavy oil. The volumes required depend on the properties of the diluent and its interaction with the extra-heavy crude but a shortage of diluent is predicted with the rapid increase in production. A return line for diluent could transform the problem into one of capital expenses. Diluent would be added near the production facilities and it would be separated at the upgrading or refining facilities. Once separated, it would be returned to the production facility for re-use. Another option is to build upgrading facilities near the production facilities. This would generate opportunities for synergies between the generation of heat

for production and the upgrading of heavy oil. Such efforts are underway for new production and Syncrude is an example of an upgrader near the production area (Fort McMurray). In addition the synthetic crude can be used as a diluent for heavy oil increasing the potential handling capacity. The compatibility of the synthetic crude and heavy oil is an issue that would need to be address.

7. Environmental concerns: mining operations have great environmental impact and in addition release considerable amounts of carbon dioxide into the atmosphere. Areas where mines exist can eventually be reclaimed and the environmental impact mitigated. On the other hand, carbon dioxide emissions from mining operations create a more pressing problem for Canada since these cannot be directly mitigated. In addition, great quantities of carbon dioxide is emitted as part of the steam generation operations and as part of the upgrading processes. Carbon dioxide limitations would greatly enhance the opportunities for nuclear power plants as the source of primary energy for oil sand operations. Other environmental concern is the disposition of the produced sand which in many cases has been limited to paving access roads in the region.

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- Canadian Crude Oil Production and Supply Forecast 2006-2020 – Canadian Association of Petroleum Producers (May 2006)
- Canada's Oil Sands: Opportunities and Challenges to 2015 – An Update. National Energy Board (June 2006)

APPENDIX A: CURRENT OIL SANDS PROJECTS[10]

Company Name	Project Description	Project Location	Cost in Millions	Construction Schedule	Remarks
Albian Sands Energy Inc.	'Jackpine' Mine -- Mining and Extraction Facility phase 1	RM of Wood Buffalo (near Fort MacKay)	$2000.0		Proposed. Approved Feb 04. Phase 1 will follow Muskeg R and Scotford expansions. Includes 170MW power plant
Albian Sands Energy Inc.	Muskeg River Mine Expansion	RM of Wood Buffalo	$2500.0		Proposed for 2006 - 2009. Application filed April 2005.
BA Energy Inc.	'Alberta Heartland' Bitumen Upgrader Phase 1	Strathcona County (NW of Bruderheim)	$ 900.0	2005-2008	Under construction. Jacobs Canada / Larsen & Toubro. Approved July 2005.
BA Energy Inc.	'Alberta Heartland' Bitumen Upgrader Phases 2 and 3	Strathcona County	$2000.0		Proposed once phase 1 is completed
BlackRock Ventures Inc.	'Orion' Heavy Oil SAGD Facility (Phases 1 and 2)	MD of Bonnyville (Hilda Lake)	$ 340.0	2005-2010	Under construction. Approved Oct 2004. Phased development, building to 20,000 bpd.
Canadian Natural Resources Ltd.	'Primrose North' Cyclic Steam Stimulation (CSS) Project	Lakeland County (Primrose / Wolf Lakes)	$ 250.0	2004-2007	Under construction
Canadian Natural Resources Ltd. (CNRL)	'Primrose East' Cyclic Steam Stimulation (CSS) Project	Lakeland County	$ 600.0		Proposed for 2007 - 2008. Includes 85MW cogen plant. Application filed.
Canadian Natural Resources Ltd. (CNRL)	'Project Horizon' Mining and Drilling Project phase 2	RM of Wood Buffalo	$1700.0		Proposed for 2006 - 2009. Approved Jan 2004.
Canadian Natural Resources Ltd. (CNRL)	'Project Horizon' Mining and Drilling Project phase 3	RM of Wood Buffalo	$1400.0		Proposed for 2009 - 2012. Approved Jan 2004.
Canadian Natural Resources Ltd. (CNRL)	'Project Horizon' Mining and Drilling Project phase 1	RM of Wood Buffalo	$6800.0	2005-2008	Under construction. SNC-Lavalin / Snamprogetti Canada Inc. EPC Froth Teatment Plant SNC-Lavalin.
Connacher Oil and	"Great Divide'	RM of Wood	$ 150.0		Proposed for 2006

[10] Source: Alberta Economic Development; http://www.alberta-canada.com/statpub

Company Name	Project Description	Project Location	Cost in Millions	Construction Schedule	Remarks
Gas	SAGD Pilot Plant	Buffalo (SW of Fort McMurray)			
ConocoPhillips Canada / TotalFinaElf / Devon Energy	'Surmont' SAGD Bitumen Commercial Project	RM of Wood Buffalo (near Anzac)	$1400.0	2004-2013	Under construction. Phase 1 (2004-2006).
Devon Canada Corp.	'Jackfish' SAGD Oilsands Project Phase 2 (J2)	RM of Wood Buffalo (SE of Conklin)	$ 500.0		Proposed for 2008 - 2009. Planned facility construction start third quarter 2008. Decision mid-2006.
Devon Canada Corp.	'Jackfish' SAGD Oilsands Project Phase 1	RM of Wood Buffalo (SE of Conklin)	$ 450.0	2005-2007	Under construction. Approved Dec 2004.
EnCana Corporation	Foster Creek Commercial Thermal Recovery Project phase 2	Lakeland County (Foster Creek)	$ 440.0		Proposed. Applications filed. Will include 80MW co-gen plant.
EnCana Corporation	Foster Creek Commercial Thermal Recovery Project Phase 3	Lakeland County (Foster Creek)	$ 844.0		Proposed construction start 2007. Applications filed May 02.
EnCana Corporation	SAGD Bitumen Production	RM of Wood Buffalo (Christina Lake)	$ 575.0	2000-2009	Under construction. AMEC / Titan Projects JV(EP & CM). Three phases. Planned construction phase 3 2007 - 2009.
Fort Hills Energy Corp.	BITUMEN UPGRADER PHASE 1	Sturgeon County (near Redwater)	$5000.0		Proposed for 2008 - 2011. Pending approvals. Preliminary fgures.
Husky Energy Inc.	'Tucker Lake' SAGD Project	MD of Bonnyville (NW of Cold Lake)	$ 500.0	2005-2006	Nearing completion. Approved July 2004. Nordic Acres Engineering (FEED). SNC-Lavalin / PCL Industrial Management (Central Plant).
Husky Energy Inc.	'Sunrise Thermal Project' Phase 2	RM of Wood Buffalo	$1900.0		Proposed for 2012 - 2014.
Husky Energy Inc.	'Sunrise Thermal Project' SAGD Oilsands Project Phase 1 (Kearl Lease 187)	RM of Wood Buffalo (N of Fort McMurray)	$ 800.0		Proposed for completion by 2012. Application approved. Corporate approval by end 2006.
Husky Energy Inc.	Heavy Oil Upgrader Expansion	Lloydminster	$2300.0		Proposed. Detailed engineering work to start.
Imperial Oil	Extension of	MD of	$ 350.0	2005-2006	Under construction. Approved

Company Name	Project Description	Project Location	Cost in Millions	Construction Schedule	Remarks
Limited	Phases 9 & 10 'Mahihkan North'	Bonnyville			Feb 2004.
Imperial Oil Resources	Heavy Oil Plant Expansion Phases 14 to 16 'Nabiye'	MD of Bonnyville (north of Marie Lake)	$ 650.0		Proposed. Includes wells, field facilities and a plant to generate steam, process bitumen and treat water. Approved Feb 2004.
Imperial Oil Resources / ExxonMobil Canada	'Kearl Lake' Oilsands Mine (Kearl Lease 187) Phase 1	RM of Wood Buffalo	$2300.0		Proposed for 2007 - 2010, pending approvals. Three production trains / phases of development in total. Application filed for regulatory approval for all three phases. Public hearings fall 2006.
Japan Canada Oil Sands Limited (JACOS)	Hangingstone SAGD Commercial Production Project	RM of Wood Buffalo (S of Fort McMurray)	$ 450.0		Proposed. Two phases. Planned construction start 2006.
North American Oil Sands Corp.	'Kai Kos Dehseh' BITUMEN PRODUCTION (SAGD) PROJECT PHASE 1	RM of Wood Buffalo	$ 850.0		Proposed
North West Upgrading Inc.	Bitumen Upgrader Phases 2 and 3	Sturgeon County (near Redwater)	$3200.0		Proposed for 2010 to 2015. Application filed January 2006.
North West Upgrading Inc.	Bitumen Upgrader Phase 1	Sturgeon County	$1600.0	2007-2009	Announced. Pending approvals expected by early 2007. Application filed January 2005.
OPTI Canada / Nexen Inc.	'Long Lake' Water Treatment and Steam Generation Facility Expansion	RM of Wood Buffalo	$ 250.0		Proposed
OPTI Canada / Nexen Inc.	'Long Lake' SAGD Project Phase 2 (Kinosis)	RM of Wood Buffalo	$2790.0		Proposed for 2008 - 2010. Cost estimates are preliminary.
OPTI Canada Inc. / Nexen Inc.	'Long Lake' SAGD Heavy Oil Project Phase 1	RM of Wood Buffalo (near Anzac)	$3840.0	2004-2007	Under construction. Flint Infrastructures Ltd., Ledcor Projects Inc., Colt Engineering, Fluor. Approved Aug 2003. Upgrader, co-gen facility (370MW) and

Company Name	Project Description	Project Location	Cost in Millions	Construction Schedule	Remarks
					upgrader capacity.
Petro-Canada / UTS Energy / Teck Cominco	'Fort Hills' SAGD Project Stage 2	RM of Wood Buffalo	$1300.0		Proposed
Petro-Canada / UTS Energy Corp. / Teck Cominco	'Fort Hills' Oilsands Project	RM of Wood Buffalo	$2000.0		Proposed for 2006 - 2010. Planned construction start mid - 2006, production start in 2011.
Petro-Canada Oil and Gas	Strathcona Refinery Conversion to Upgrade Bitumen	Strathcona County	$1600.0	2004-2008	Under construction. Approved.
Petro-Canada Oil and Gas	MacKay River SAGD Expansion	RM of Wood Buffalo (NW of Fort McMurray)	$ 810.0		Proposed. Application filed Dec 05.
Petro-Canada Oil and Gas / Nexen Inc.	'Meadow Creek' SAGD Bitumen Production	RM of Wood Buffalo (S of Ft McMurray)	$ 800.0		Proposed. Application under review. Project includes 330MW co-gen plant.
Shell Canada	Scotford Upgrader Expansion (De-bottleneck and Addition of Third Bitumen Processing Train)	Strathcona County (Scotford)	$2700.0	2006-2010	Announced. Application filed April 2005. Public hearing Dow Centre on June 26.
Suncor Energy Inc.	Steepbank Mine Extension	RM of Wood Buffalo	$ 350.0		Proposed for 2007 - 2010. Application filed. Public hearing July 5, Fort McMurray.
Suncor Energy Inc.	New Bitumen Production Facilities at 'Firebag' Site	RM of Wood Buffalo	$1000.0		Proposed for 2005 - 2007. Approved Mar 2004.
Suncor Energy Inc.	'Voyageur' Oil Sands Facility Expansion (Third Oil Sands Upgrader)	RM of Wood Buffalo	$5900.0		Proposed for 2007 - 2010. Applications filed March 2005. Preliminary cost estimate. Project does not include bitumen feed to upgrader. Public hearing July 5 Fort McMurray.
Suncor Energy Inc.	Petroleum Coke Gasifier for 'Voyageur' Upgrader	RM of Wood Buffalo	$ 600.0		Proposed. Included with application for Voyageur upgrader March 2005. Cost estimate preliminary.
Suncor Energy Inc.	Upgrader Expansion	RM of Wood Buffalo	$2100.0		Proposed for 2006 - 2008. Approved Mar 2004. Corporate approval announced.
Syncrude Canada	Phase 4:	RM of Wood	$2300.0		Proposed. Pre-engineering

Company Name	Project Description	Project Location	Cost in Millions	Construction Schedule	Remarks
Ltd.	Upgrader Expansion Phase 2 / Aurora Mine Train 3	Buffalo (Fort McMurray)			study underway (AMEC). Expansion SNC-Lavalin, Fluor Daniel. Train 3 AMEC. To be considered by 2016.
Syncrude Canada Ltd.	Continuous Improvement	RM of Wood Buffalo (Fort McMurray)	$1500.0	1997-2007	Underway
Syncrude Canada Ltd.	Sulphur Emission Reduction Program (SERP)	RM of Wood Buffalo (Mildred Lake)	$ 400.0		Proposed for 2005 - 2009. Application approved.
SynEnCo Energy Inc. / SinoCanada Petroleum Corp.	'Northern Lights' Bitumen Upgrader	Sturgeon County	$3600.0		Proposed for 2008 - 2010. Application to be filed late 2006.
SynEnCo Energy Inc. / SinoCanada Petroleum Corp.	'Northern Lights' Oilsands Mine and Extraction Plant phases 1 and 2	RM of Wood Buffalo	$2500.0		Proposed for 2008 - 2010. Application to be filed by mid-2006. Colt/AMEC.
Total Canada Ltd.	'Joslyn Creek' SAGD Project Phase 3 and North Mine Development	RM of Wood Buffalo	$1500.0		Proposed construction start Phase 3 in 2007, mine in 2008. Application for phase 3A filed. Application for mine filed early 2006.
Total Canada Ltd.	Bitumen Upgrader	Strathcona County or Wood Buffalo	$5000.0		Proposed. $US. Decision by mid-2006. Upgrader to be built by 2014.