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CARBON CAPTURE AND STORAGE IN THE ALBERTA OIL SANDS – A DANGEROUS MYTH

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FOREWORD

WWF Foreword to CCS in Oil Sands Report

The oil sands are located in Canada but their exploitation and the resulting greenhouse gas emissions have international implications. They are the largest reserve of petroleum in the world outside of Saudi Arabia, but the energy needed to extract and process this type of unconventional oil results in greenhouse gas emissions per barrel around three times those of conventional oil.

This December world leaders will meet in Copenhagen to agree how the world will tackle the growing climate crisis by cutting greenhouse gas emissions. It is hoped this will be part of a global shift towards a low carbon economy. Developed countries like the UK and Canada have a leading role to play and need to reduce their emissions by at least 40% by 2020 and almost completely decarbonise by 2050.

Both countries will need to make significant changes to their current policies if they are to meet these targets. In Canada, even with an aggressive application of carbon capture and storage (CCS) technology, the upstream emissions from the oil sands alone would take up the entire carbon budget for Canada under the 80 per cent reduction scenario called for by scientists and agreed to by Canada at the 2009 G8 meeting.

However, the oil sands present not only an environmental threat but also an economic one.

In a highly carbon constrained world the price of carbon will increase. This means that companies committed to long-term projects with high carbon emissions will become increasingly unprofitable, threatening people's investments and pension funds. This is beginning to be recognized and a recent survey of UK fund mangers found a significant number in favour of mandatory emissions reporting for companies, as this would help them to manage the exposure of their assets to carbon risks.

CCS technology – capturing the carbon dioxide emissions from oil sands operations and storing them underground – has been put forward by the governments of Canada and Alberta, as well as many oil industry representatives, as their central strategy for managing greenhouse gas emissions in this sector.

This report examines the potential of CCS technology to reduce emissions from the Canadian oil sands, as part of WWF's broader work on defining practical solutions and clear imperatives for meeting global energy demand without damaging the global climate.

The conclusion of this report is that the application of CCS technology to unconventional oil is simply too little, too late, and too expensive to qualify as a climate solution.

There are also a range of other ecological and social costs from oil sands development which cannot be resolved by the application of carbon capture and storage technology.

Investing heavily in oil sands is diverting money away from transforming the global economy into a sustainable one fit for the 21 century. We believe there should be greater transparency in the reporting of carbon emissions by companies to allow investors to assess the risks posed by carbon intensive projects. Ultimately this will mean that the money will be invested in other projects which have lower greenhouse gas emissions.

WWF-UK is calling for a halt to the expansion of oil sands in Canada and the introduction of mandatory carbon reporting by companies in the UK as set out in the Climate Change Act 2008.

David Norman
Director of Campaigns
WWF-UK

EXECUTIVE SUMMARY

The application of Carbon Capture and Storage (CCS) has been widely cited by supporters of the oil sands as justification for ongoing expansion activities. This study exposes the myth of CCS in the oil sands, finding it to have no serious ability to mitigate greenhouse gas emissions anytime this side of 2050. In its application to oil sands developments, CCS has limited potential to reduce upstream emissions to levels comparable with the average for conventional oil. Crucially, CCS will not enable oil sands products to meet emerging international low carbon fuel standards or enable Canada to meet its international climate change commitments.

Alberta's proven economically recoverable oil sands reserves amount to 173 billion barrels of oil equivalent, with estimates for bitumen in place between 1.7 and 2.5 trillion barrels, making it second only to Saudi Arabia in proven reserves. Production reached 1.3 million barrels per day (bpd) in 2008 and current projections place production between 2.5 and 4.5 million bpd by 2020, with production capacity possibly as high as 6.2 million bpd.

The extraction of oil from the oil sands is incredibly energy intensive. Studies have estimated that well-to-refinery emissions are on average three times more carbon intensive than for conventional oil and that Well-to-Wheel emissions are between 14 and 40% higher than the current average for conventional crude sources. These figures do not include emissions resulting from the destruction of boreal ecosystems.

In 2007, Canada's total greenhouse gas (GHG) emissions were 26% higher than 1990 levels and 34% higher than its then agreed Kyoto target. Furthermore, according to the Intergovernmental Panel on Climate Change (IPCC), industrialised nations should seek to reduce emissions by between 25 and 40 per cent below 1990 levels by 2020, and 80 to 90 per cent by 2050 (IPCC 2007). It would appear that Canada's current model of economic development is totally ill suited to its international environmental obligations.

Carbon capture and storage (CCS) has been cited by supporters of the oil sands as the solution. It has been claimed that separation of CO_2 from combustion streams and from industrial processes is common in a number of industries and underground gas storage has substantial history as a result of acid gas storage and enhanced oil recovery (EOR) projects. However, even the most optimistic estimates from industry experts claim reductions from oil sands upstream operations will be 10-30% in the medium term (and only for the more favourable sites) and 30-50% in the long term. Reductions of around 85% are required to make oil sands emissions comparable with the average for conventional oil production.

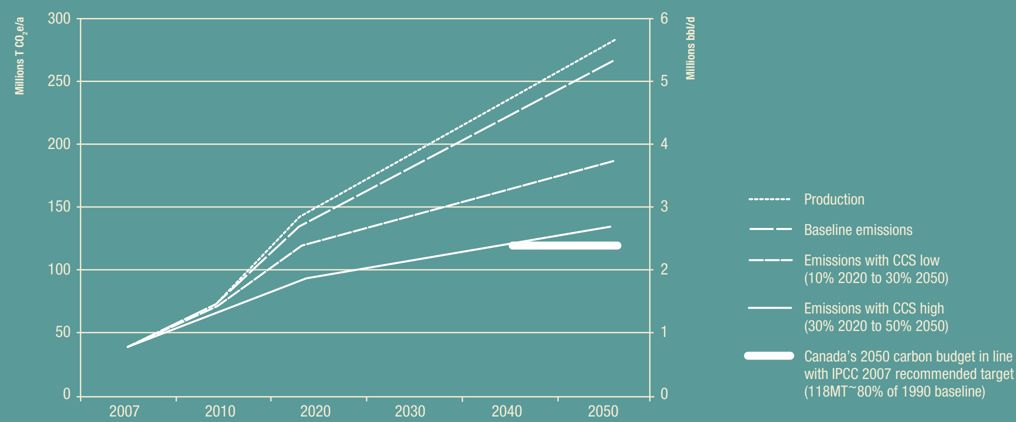
The maximum reductions achievable using CCS would therefore be insufficient to meet emerging low carbon fuel standards, such as those in the European Union and California, even by 2050.

Furthermore, CCS cannot address the even larger downstream emissions associated with burning the resulting fuel in vehicles, so that on a full lifecycle basis, emission reduction potential is likely in the 7 to 11 per cent range.

Significant barriers exist to CCS achieving its maximum potential in connection with the oil sands. Not least its expense, with estimates of between \$60 to \$290 per tonne of CO_2 captured (\$200 to \$290 for in situ production); which compares poorly with emissions capture from larger, highly concentrated sources, such as coal fired power stations. It has been estimated that subsidies of \$1 to \$3 billion per year would be required from the governments of Alberta and Canada to successfully promote CCS projects in Alberta. If these funds are invested in oil sands operations, then it is a major public investment in a technology that cannot deliver reductions of the magnitude that are required if we are to avoid dangerous levels of climate change.

The following graph depicts the high projected GHG emissions that would result from upstream oil sands operations under a constrained growth forecast and assuming a highly aggressive deployment of CCS i.e. 10-30% industry-wide reductions in 2020 and 30-50% in 2050. From a Well-to-Tank perspective, the emissions from the Alberta oil sands alone would exceed Canada's entire carbon budget for 2050, were it to meet what many consider to be a fair and appropriate GHG reduction target of 80% compared to 1990 levels by 2050. This chart does not consider additional energy used for CCS, the destruction of boreal ecosystems, tailings ponds and other emissions, or choice of energy supplies with a higher carbon content.

Figure 1.1-1 Estimated Upstream (Well-to-Tank) Emissions with and without CCS



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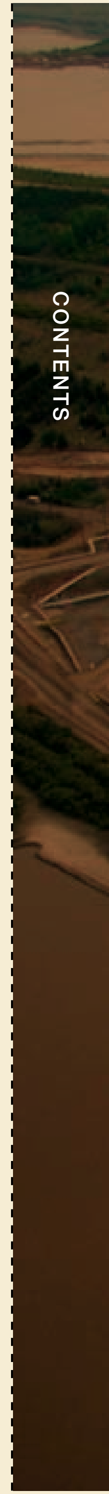



An estimated 1.7 to 2.5 trillion barrels of oil are trapped in a complex mixture of sand, water and clay.

ALBERTA OIL SANDS

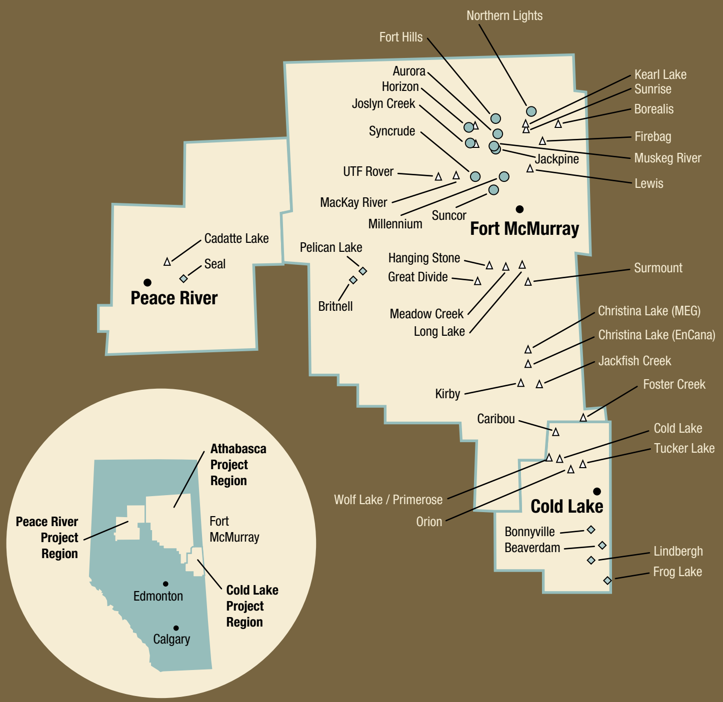
1.1 Introduction to the Oil Sands

Alberta's oil sands contain the second largest proven reserves of oil in the world. Alberta's proven oil reserves as oil sands that are economically recoverable amount to 173 billion barrels (Alberta Energy, 2008), but estimates for bitumen in place are between 1.7 and 2.5 trillion barrels (Oil Sands Discovery Centre). Unlike conventional crude oil, the oil sands must be mined or recovered in situ. The three regions of deposits – Athabasca, Peace River, and Cold Lake – comprise a total of 140,200 km2 (refer to Figure 1.1.1-1, Alberta Energy, 2009). Bitumen comprises approximately 10-12% of the actual oil sands, while 80-85% is comprised of mineral matter such as sand and clay and 4-6% is comprised of water (Alberta Energy, 2009).

1.1.1 History and motivation

The first attempts to develop the Athabasca Oil Sands commercially, from 1906 to 1917, were made under the assumption that the bitumen in the area must be coming from pools of oil deep beneath the surface. The Alberta Research Council (ARC) was established in 1921 and supported early research on separation of bitumen from sand and a demonstration project was carried out during the 1940s and 1950s. It was not until 1962 that oil sands development started in earnest, when the Government of Alberta announced a policy in which oil sands production would supplement, but not displace, conventional crude oil production in the province. As a result, the Great Canadian Oil Sands (GCOS) Project, ultimately owned by Suncor, came on stream in 1967 to become the world's first oil sands operation (Humphries, 2008).

Figure 1.1.1-1 Oil Sands Regions in Alberta (Alberta Government, 2006)



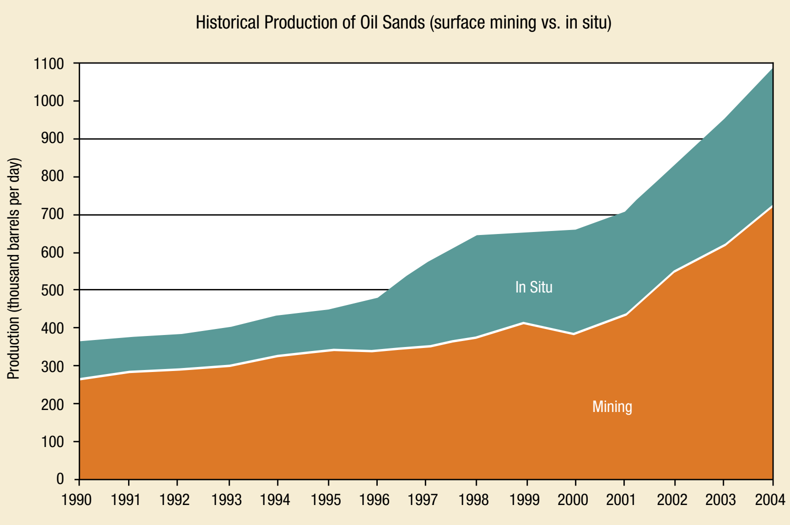
1.1.2 Growth rate

Production has steadily increased since the first oil sands development, the GCOS project in 1967. According to the Canadian Association of Petroleum Producers, oil sands production accounted for 62% of Alberta's total crude oil and equivalent production in 2004. The share is expected to be 87% by 2015, with light conventional crude oil production continuing to decline (CAPP, 2009). Figure 1.1.2-1 shows historic production broken down by type of mining while Figure 1.1.2-2 shows historic production broken down by resulting product. Production in 2008 stood at 1.3 million barrels per day (bpd).

1.2 Harvesting the Oil Sands

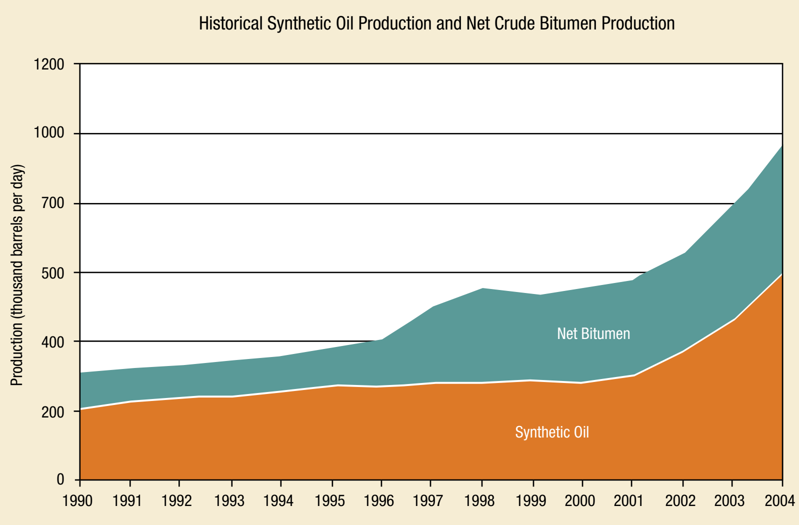
The Northern Alberta oil sands are considered to be one of the largest industrial projects in the world, and consequently, a significant contributor to growing GHG emissions. Oil sands activities can be classified into two types of operations: surface mining and in-situ.

Figure 1.1.2-1 Bitumen Production by Type of Mining



Source: Derived from Alberta Energy and Utilities Board ST 39 & ST 53

Figure 1.1.2-2 Bitumen Production by Product



Source: Alberta Energy and Utilities Board ST 39 & ST 53

1.2.1 Surface Mining

In surface mining operations, oil sands are mined using shovel-and-truck technology (Figure 1.2.1-1). The oil sands are loaded onto hauler trucks and transported to crushers. The crushers break down the ore into smaller pieces and the material is turned into a slurry with the addition of hot water. The mixture is passed through vibrating screens to separate large particles before the addition of air and caustic soda. The resulting slurry is then pumped to the extraction plant for separation of the coarse tailings from the slurry.

The main component of the extraction plant is the Primary Separation Vessel (PSV), which produces an overflow stream of bitumen, combined with water, clay, and sand fines. This stream, generally referred to as Froth, is further processed in the Froth Treatment Plant. The PSV produces an underflow stream of water and coarse solids which is pumped to the tailings ponds for recovery of the water for reuse, and deposition of the sand for dyke construction. In the PSV, a middlings layer is extracted and processed through a series of aerated flotation cells to recover residual bitumen, which is combined with the Froth overflow from the PSV. Underflow from the flotation cells, "Flot Tails", is either sent to the tailings ponds, or thickened to recover heat and water and the thickened tails sent to the tailings ponds.

In the Froth Treatment Plant, the bitumen is heated and diluted with a solvent to facilitate removal of residual water and fine solids. After solids removal, the solvent is recovered from the bitumen. Solvent recovery is a thermal process, requiring significant energy inputs, with energy recovered in the Froth Treatment Plant partially used to heat water for the extraction process. The bitumen is then processed on-site or sent for processing, pipelined as hot bitumen, or diluted with a lighter hydrocarbon and pipelined as diluted bitumen or 'dilbit'.

1.2.2 In-situ Extraction

The vast majority of Alberta's oil sands are buried too deep to allow surface mining operations. This oil is recovered by in situ techniques. Steam Assisted Gravity Drainage (SAGD) is the most commonly used type of in situ technology whereby steam is injected into the reservoirs via horizontal injection wells to heat the oil and lower the bitumen's viscosity. A parallel producer well collects the bitumen and the mixture is transported by pipeline to a centralized facility where the produced water is recovered, treated, turned into steam, and recycled back to the reservoir. Diluent is delivered to the centralized facility via pipeline and is blended with the bitumen. The diluted bitumen (dilbit) is then transported via pipeline to the upgrading facility. In some cases, a hot bitumen product can be sent directly to the upgrader facility.

Figure 1.2.1-1 Oil Sands Mining,
Photo by David Dodge courtesy of The Pembina Institute,
(www.OilSandsWatch.org)

Cyclic Steam Stimulation (CSS) is a technique whereby steam, injected into a heavy oil reservoir, is shut-in and allowed to "soak" the formation to mobilize the cold bitumen. After heating, the flow on the injection well is reversed producing oil through the same well bore. This cycle of soak-and-produce is repeated when oil production rates drop below a critical threshold as a result of the reservoir cooling. The choice between SAGD and CSS depends on reservoir properties including reservoir depth and quality. Generally, in Cold Lake and Peace River where reservoirs are deeper, CSS is preferred to SAGD; in Athabasca where oil sands are shallower and there is a lack of a capping formation, CSS is less viable and SAGD is the preferred production method.

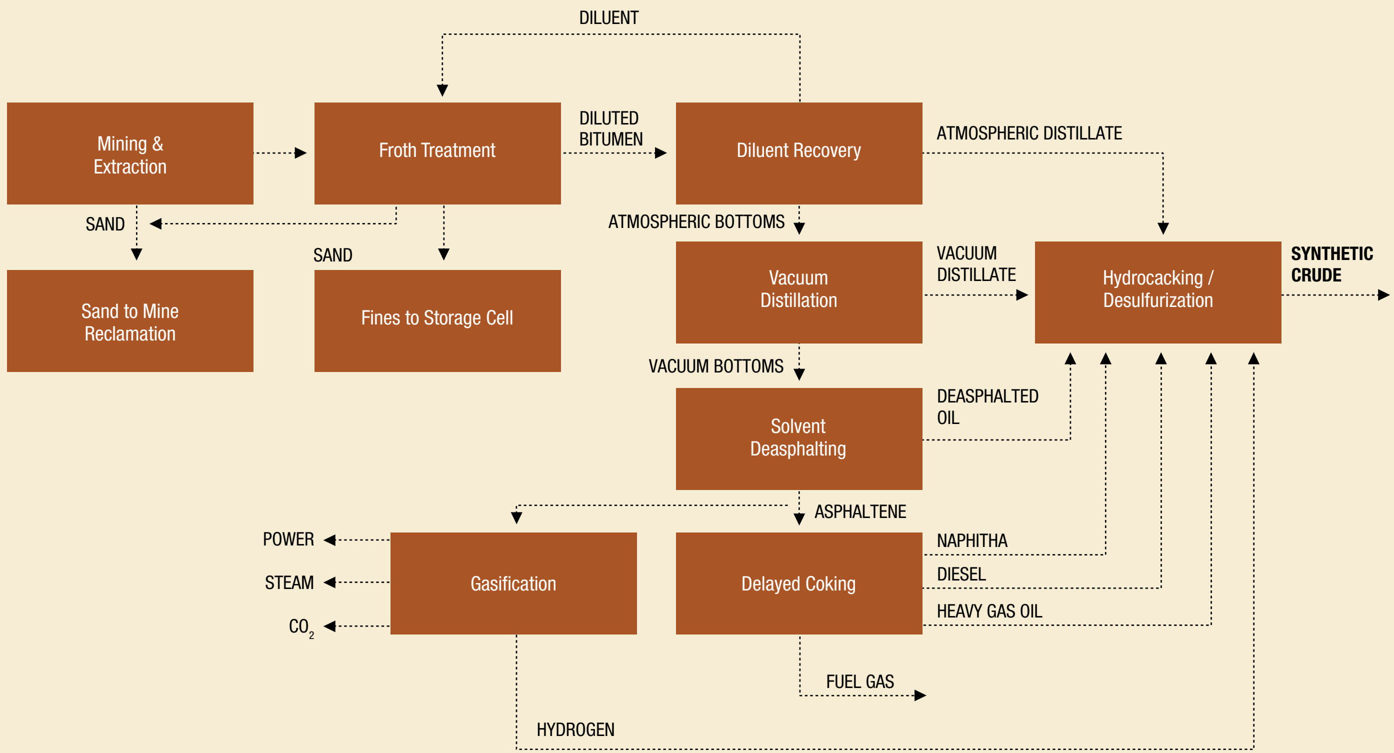
1.2.3 Upgrading

At the upgrading facility, a series of distillation systems is used to sort the hydrocarbon into different components and the diluent is also recovered during distillation and sent via pipeline back to the extraction facilities. The bottoms from the vacuum distillation is sent to a hydrocracking unit where large hydrocarbons are cracked and recombined with hydrogen to create products that can be used to create a high quality synthetic crude. The cracked oil together with the gas oils is sent to hydrotreating and stabilization where more hydrogen is added to further upgrade the oil and improve its properties. The hydrotreating operation also removes impurities such as sulphur and nitrogen, producing a sweet oil. The resulting products are blended to produce a sweet synthetic crude that can be pipelined to a refinery (Figure 1.2.3-1).

1.2.4 Refining

Once at the refinery, the SCO undergoes distillation and vacuum distillation to create various fuels. The distillate from the crude distillation processes is sent to hydrotreaters and naptha reformers, and distillate from vacuum distillation is sent to a Fluid Catalytic Cracking (FCC) unit. The fuels resulting from refining operations include kerosene, diesel, LPG, and various gasoline oils.

Figure 1.2.3-1 Process steps for recovery of synthetic crude oil from oil sands mining (adapted from Colt Engineering, 2007)



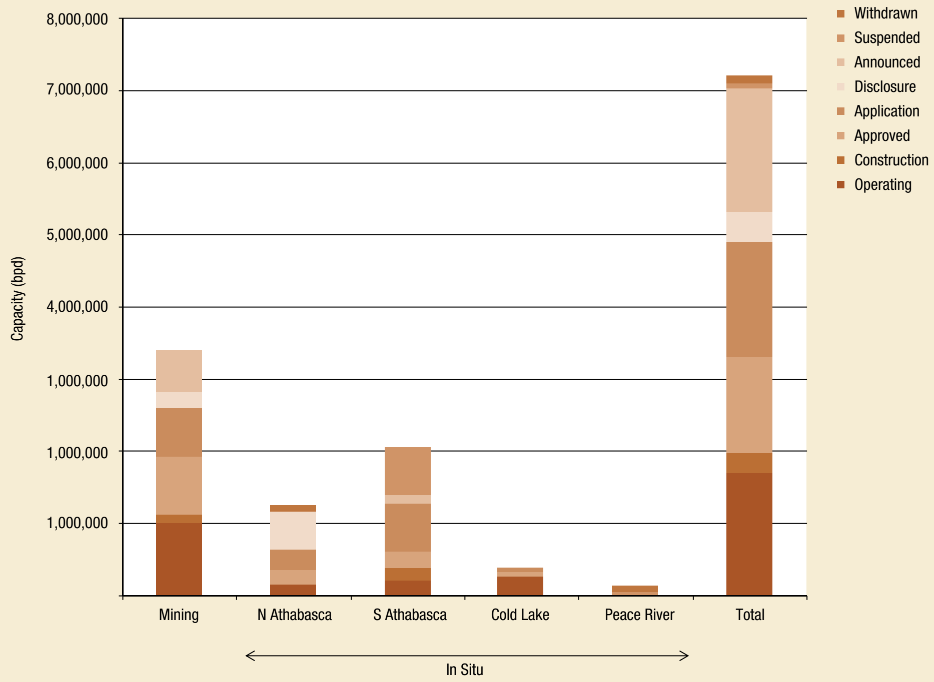
1.3 Production Trends

Oil sands production has been growing rapidly, driven by rising prices during the past several years, although the recent drop in oil prices and increasing cost of labour has temporarily slowed growth forecasts. Projections are typically based on projects announced, with consideration of project schedules, technologies, and stages of development.

1.3.1 Current Trends

Approximately C$125 billion in capital expenditures have been publicly announced for the period 2006 to 2015; however, since 2008, various companies have withdrawn applications for projects, announced delays, and/or placed their projects on hold pending financial review. A total of 7.0 million bpd capacity of existing and proposed operations remains as of February 2009, with start-up dates for 5.0 million bpd to be determined. The profile of projects in the various regions of Alberta is shown in Figure 1.3.1-1. Figure 1.3.1-2 shows projected total bitumen production growth from the oil sands given different economic scenarios.

Figure 1.3.1-1 Existing and Proposed Bitumen Producers, February 2009 (Dunbar, February 2009)



1.3.2 The Economics of the Oil Sands

Oil sands projects, particularly upgraders, are capital intensive and consequently, the project economics are extremely sensitive to raw materials and labour costs. The equivalent operating costs for oil sands activities have changed dramatically over time in terms of real dollars and stated break even prices have varied dramatically over the last few years. They are influenced by the pace of growth of the oil sands, global price of oil, and more recently by growing environmental concerns reflected in new Low Carbon Fuel Standard (LCFS) in California and the Specified Gas Emitters Regulation (SGER) in Alberta.

The recent period of high commodity prices together with regional labour shortages caused by rapid expansion (Figure 1.3.2-1) increased the required break even price for oil. The rapid expansion of oil sands projects in Alberta has also added inflationary pressures, increasing engineering, materials, and construction costs for new developments.

Existing operations are also sensitive to rising energy costs, because significant amounts of natural gas are currently used in the mining and upgrading process. Lower cost alternatives to natural gas are occasionally employed while newer technologies that can hedge against future rises in energy costs are being sought. Gasification of petcoke and other residues, nuclear energy, and geothermal energy sources are current options under investigation. Costs of carbon emissions are also a concern, particularly for large emitters in Alberta who are subject to the SGER.

Figure 1.3.1-2 Projected total bitumen production growth given different economic scenarios (McColl, February 2009)

Bitumen Production Capacity, Million Barrels per Day (mmbpd)

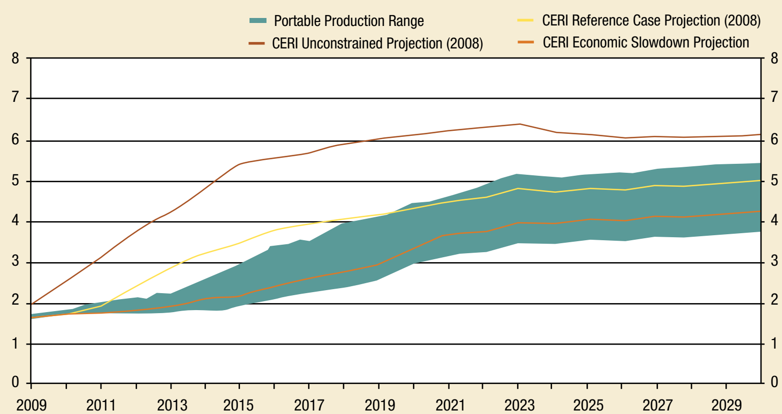
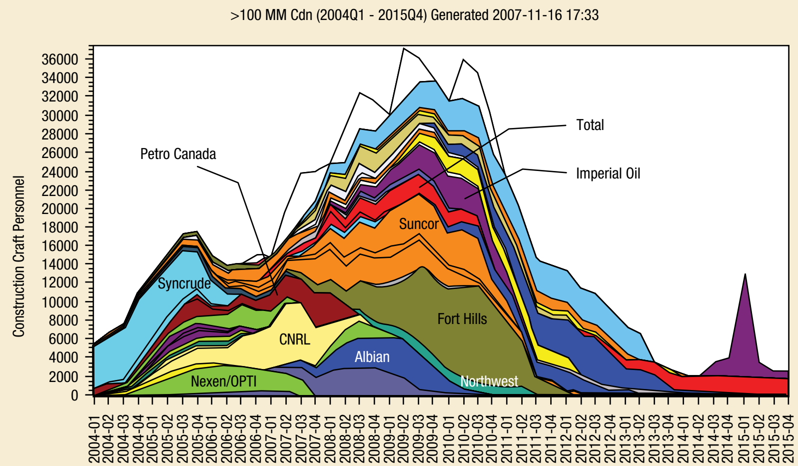


Figure 1.3.2-1 Industrial Construction Projects and Personnel Required



1.4 Other Environmental Impacts

While oil sands operations in Alberta are significant contributors to GHG emissions in Canada, it is important to keep in mind that reducing GHGs is only one part of sustainable development. Oil sands operations in Alberta have had significant adverse environmental and social impacts due to other aspects of their operations, such as tailings ponds, air emissions, and land and water usage.

1.4.1 Emissions to air

Though GHGs are a frequently area of focus, they are only a portion of the atmospheric emissions that arise from oil sands development and energy use. Many of the other air emissions associated with these activities, such as NOx and SOx, have other effects on plant and animal life, such as the production of acid rain.

1.4.2 Land impacts

Oil sands mining activities disturb large quantities of land, removing it from use by wildlife and other activities including as a carbon store through standing timber, peatland and wetlands. In-situ activities have fewer visible land impacts than mining activities, but larger impacts in other areas, including energy and solvent use. Studies have additionally shown that characteristic land-disturbances of in-situ site development (seismic lines, access roads, etc.) can have a disproportionately large impact on wildlife such as Woodland Caribou (Dyer et. al. 2001).

1.4.3 Water impacts

Enormous quantities of water, typically drawn from freshwater sources, is used for steam production for in-situ production and is used to separate synthetic crude from bitumen. Significant quantities are consumed and disposed of with thicker oil and waste from oil sands activities in tailings ponds (Holroyd & Simieritsch, 2009). Between two and four barrels of water are consumed for each barrel of synthetic crude oil produced from mining operations, and about half that is consumed for in-situ operations (Griffiths and Woynillowicz, 2009).

1.4.4 Tailings ponds

Current mining practices produce a fluids tailings stream that is currently contained in tailings ponds covering over 130 square kilometers. Tailings consist of water, sand, silt clay, unrecovered hydrocarbons and water with dissolved components. The toxic effects of tailings pond water has been documented since the early stages of oil sands development and the toxicity is primarily due to organic acids, particularly napthenic acids. Amongst the compounds detected in tailings pond water are benzene, toluene, phenol, and polycyclic aromatic hydrocarbons (PAHs); trace metals such as lead and arsenic have also been found in tailings pond water (Allen, 2008). Given the toxic composition of tailings, tailings waste must be held and managed on-site. As these resemble natural water sources, they attract birds and wildlife that are trapped in the thick fluid and unable to escape. Leakage from tailing ponds into the surrounding area has the potential cause further damage to the environment and wildlife if improperly managed (price, 2008). No tailings pond has been reclaimed to date (Grant et. al, 2008) and estimates of methane generation shown potential for significant emissions and a large error margin in current accounting (Siddique et. al., 2008).

1.4.5 Biodiversity

Both mining activities and in-situ can destroy and significantly fragment wildlife habitat, and pipeline infrastructure for carbon transport and storage will contribute to this problem. Alberta's woodland caribou, for example, is an endangered species which studies have shown to be been seriously affected by industrial activities in the region (Dyer et. al. 2001). Additionally there are a large number of under-examined impacts on species health as a result of oil and gas development activities in general potentially affecting humans (Witter et. al. 2008) as well as aquatic species and wildlife (Lister 2007).

1.4.6 Indigenous communities

These environmental impacts are also adversely affecting local indigenous communities. A number of First Nations are opposed to the unsustainable development of the oil sands on this basis. A statement of claim was filed in May of 2008 by the Beaver Lake Cree Nation that listed more than 17,000 approved or proposed developments in their traditional lands, near Lac La Biche.

The band claims the developments have forced members out of traditional areas, degraded the environment and caused a decline in wildlife, making it impossible for them to meaningfully exercise their Treaty 6 rights to hunt, trap and fish.

The greenhouse gas intensity of oil sands production is on average three times greater than for conventional oil.

GHG EMISSIONS FROM OIL SANDS

2.1 Greenhouse Gas Emissions from Oil Sands Operations

In signing and ratifying the Kyoto Protocol, Canada committed to reduce its emissions to 6% below 1990 levels on average during the period from 2008-2012. Canada is way off track to meet that commitment. Environment Canada estimated that total GHG emissions in Canada in 2007, expressed as "CO_2 equivalent," (CO_2e) were 747 Mt, 26% higher than 1990 levels and 34% higher than the Kyoto target of 558 MT (Figure 2.1-1). According to the Intergovernmental Panel on Climate Change (IPCC), industrialised nations should further reduce emissions by between 25 and 40 per cent below 1990 levels by 2020, and 80 to 90 per cent by 2050 (IPCC, 4th Assessment Report, Working Group III Report Mitigation of Climate Change, 2007, p. 776).

Extraction of oil from the oil sands is an energy intensive process. Consequently, some of the largest emitters of greenhouse gases are companies involved in oil sands operations. The oil sands mining operations of Syncrude and Suncor are Canada's 3rd and 6th largest emitters of GHGs, respectively. Between 1990 and 2003, the average emission intensity for producing oil from oil sands operations declined by 23%, largely as a result of declining emissions associated with fossil fuel combustion. While the greenhouse gas intensity of oil sands production has been declining, the cumulative emissions from the industry have been increasing, due to the rapid expansion of oil sands activities. Between 1990 and 2006, bitumen and SCO production from oil sands operations increased by about 230% (Environment Canada, November 2008). Expansion plans for oil sand operations involve deeper and more difficult to access reserves and include an increased proportion of in-situ operations, from 40% of the 1.7 million bpd in production capacity in 2009 to 52% of the proposed 7.0 million bpd capacity (Strategy West, February 2009). In-situ operations as currently operated are more carbon intensive than surface mining and as a result, the greenhouse gas intensity of oil sands production may begin to rise again.

Figure 2.1-1 Canada's Greenhouse Gas Emissions 1990-2007 (Environment Canada)

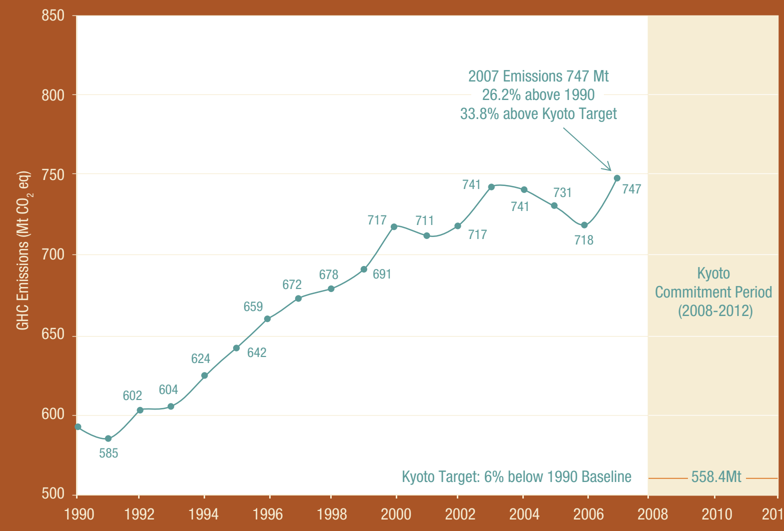


Figure 2.1-2 shows the various activities from which GHG emissions arise from a life cycle basis. A life-cycle basis considers all direct and indirect emissions from extraction at the well to combustion of the final transportation fuel, and is often referred to as a 'Well-to-Wheels' assessment. From a life cycle perspective, the most significant source of greenhouse gas emissions from oil sands processes are fuel combustion associated with power generation, extraction, upgrading and refining and combustion of the resulting fossil fuel products by downstream users.

2.2 Review of LCA Studies

There are relatively few life cycle analyses of oil sands operations that have been completed. Understanding greenhouse gas emissions from a life cycle analysis is critical to assessing where opportunities for carbon capture and storage exist and how significant an impact carbon capture and storage can have on overall GHG emissions.

2.2.1 GHG Emissions from Construction

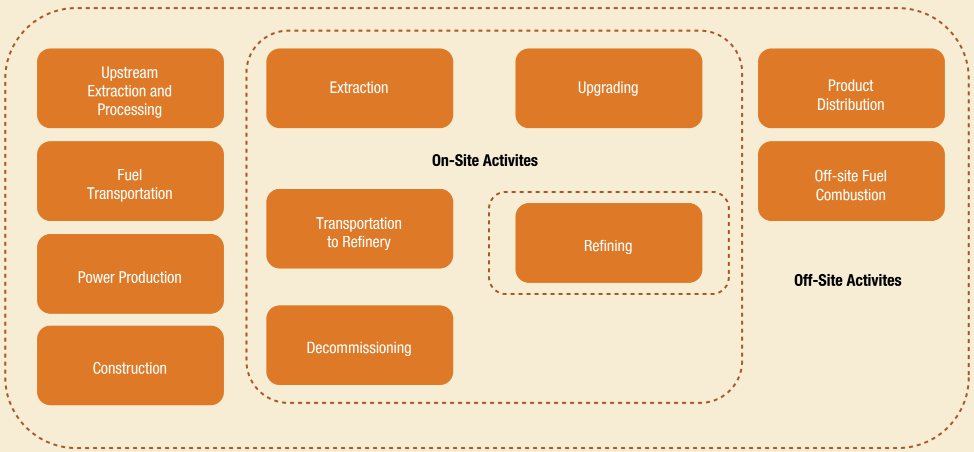
Very few studies have characterised GHG emissions associated with the construction of new facilities. These emissions are typically neglected in LCA studies for energy facilities as they are often an order of magnitude lower than emissions associated with fuel combustion. Bergerson and Keith (2008) suggest that for oil sands operations, GHG emissions from construction are significant and may comprise an additional 10% of total life-cycle emissions. Details about the methods used to estimate emissions from construction are not provided in their study, however and would be required for further inclusion.

2.2.2 Well-to-Upgrader: Production of Bitumen

Mining and Extraction – Surface Mining

During the mining stage, greenhouse gas emissions are largely associated with diesel fuel consumption for trucks to transport mined material from the mine site to processing area. The shovels used for extraction are primarily electric and either use grid power or power generated on-site. In the bitumen extraction stage, hot water and steam is used to separate the bitumen from the oil sand. Energy demands include electricity for equipment and hydrotransport as well as energy to produce heat. GHG emissions are also associated with surface mining tailings ponds and a large part of surface mining operations involves clearing of boreal ecosystems, the effects of which are largely unaccounted in emissions data.

Figure 2.1-2 Life Cycle Activities for GHG Emissions



Extraction – In Situ

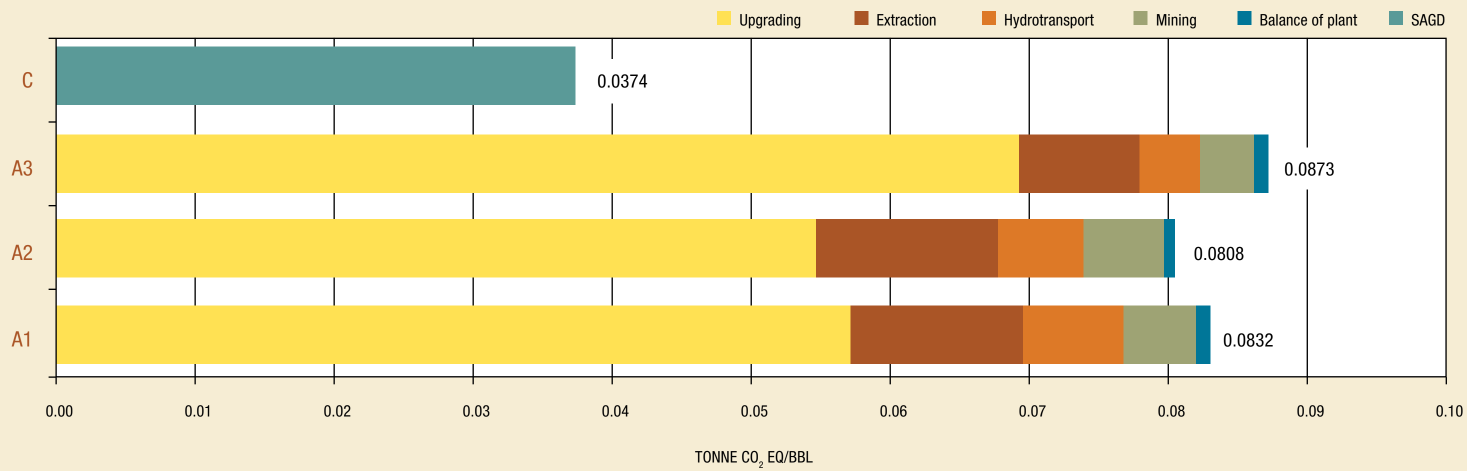
The main sources of greenhouse gas emissions during in situ extraction arise from fossil fuel combustion for the production of steam. Steam is typically produced using natural gas in steam boilers, and the steam-to-oil ratio, an indicator of efficiency of the operation, is typically between 2 and 3. Electricity and transportation fuels are also required for equipment operation.

In a report published by The Pembina Institute in 2008 (Dyer, 2008), surveys were sent to oil sands production companies with both mining and in situ operations requesting information on selected environmental performance indicators. One of these indicators was the greenhouse gas intensity for oil sands production of bitumen (i.e. before upgrading). The question asked of participating companies was: *What is your operational greenhouse gas emission intensity in kilograms (kg) per barrel (bbl) bitumen?* Responses were only received for mining activities and reported intensities between 23 and 45 kg CO_2eq/bbl bitumen. In situ operations tend to have higher greenhouse gas intensity for extraction of bitumen. More significantly, based on data reported to Alberta Environment as part of the specified gas reporting regulation to regulate greenhouse gas emissions from large industrial sources together with production data, in-situ operations resulted in between 34 and 115 kg CO_2e/bbl bitumen, with CSS operations being more intensive than SAGD operations (Alberta Environment, 2007).

2.2.3 Upgrader-to-Refinery: Production of SCO from Bitumen

During upgrading, energy consumption is significant. Large amounts of hydrogen, steam and power are required for the upgrading processes. Significant amounts of natural gas are used to create hydrogen. Hydrogen is purified using a solvent or using pressure swing adsorption (PSA). The carbon dioxide produced as a by-product is typically vented as a nearly pure CO_2 stream to atmosphere in solvent systems, or is released as part of the flue gases from the combustion of the PSA tail gas. Greenhouse gas emissions are also associated with venting, flaring and fugitive releases. In 2007, Ordorica-Garcia et al modeled the energy demands and greenhouse gas emissions of the Canadian oil sands industry. Amongst the scenarios reviewed were surfacing mining with LC Fining (Chevron's technique to treat heavy hydrocarbons with hydrogen in the presence of catalyst to produce

Figure 2.2.3-1 GHG Intensity per Process Stage (Ordorica-Garcia et al, 2007).
Scenarios reviewed were: A1 – Surface mining with LC Fining, Fluid Cracking, and Hydrotreating;
A2 – Surface mining with bitumen upgraded by delayed coking and hydrotreating;
A3 – Surface mining with upgrading by LC Fining and hydotreating; and C – SAGD bitumen production without any upgrading.



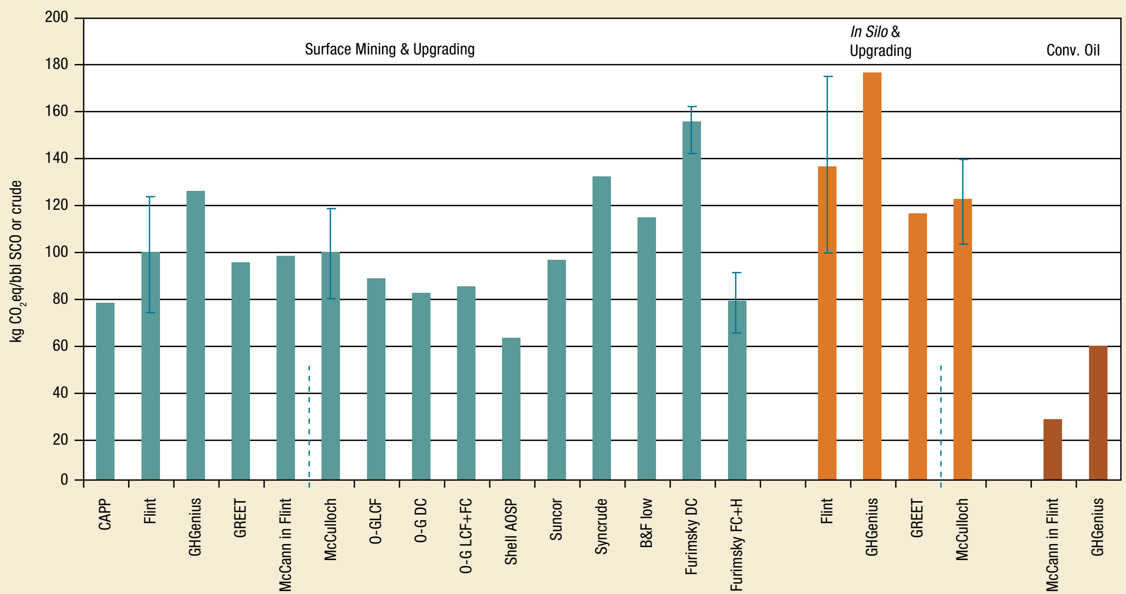
low sulfur products), FC (Fluid Coking where heat is employed rather than hydrogen for the cracking process), and Hydrotreating (A1), surface mining with bitumen upgrading by delayed coking and hydrotreating (A2), and surface mining with bitumen upgrading by LC Fining and hydrotreating (A3). The study also looked at a scenario for SAGD bitumen production without any upgrading (C). The results, reproduced in Figure 2.2.3-1, show that upgrading accounts for the vast portion of the greenhouse gases released from Well-to-Refinery in the production of SCO from surface mining operations. Upgrading typically emits between 50 and 70 kg CO_2/bbl SCO and accounts for between 65% and 85% of total GHG emissions in the production of SCO (Ordorica-Garcia et al, 2007).

Charpentier *et al* (2009) recently reviewed publicly available studies and models that estimate greenhouse gas emissions from oil sands activities. Their study aimed to provide a comprehensive review of past studies and current models; to highlight differences in emissions performances and elucidate possible causes of these differences; and to provide guidance for future studies. Figure 2.2.3-2 shows the emissions intensity from wellhead to the refinery entrance gate for synthetic crude oil production.

Variations are significant and some of the studies analyzed have quite different results, even for the same project or combination of projects. For the in situ operations, differences may be due in part to different steam-oil-ratios (SORs) assumed for each study or project. Steam production typically uses natural gas combustion, and the fuel combustion required to produce steam for SAGD operations accounts for the major part of GHG emissions.

The sustainability reports from the major industry players reveal similar numbers within the range found by Charpentier et al., Syncrude's 2007 Sustainability Report for example showed 133 kg CO_2eq/bbl of SCO production. Figure 2.2.3-2 shows surface mining and upgrading emissions vary from 60-155 kg CO_2/bbl SCO and in-situ and upgrading emissions vary from 118-178 kg CO_2/bbl SCO. For comparison, conventional oil emissions are reported to vary from 27-58 kg CO_2/bbl by Charpentier et. al.

Figure 2.2.3-2 Emissions Intensity of SCO Production (Charpentier *et al*, 2009)



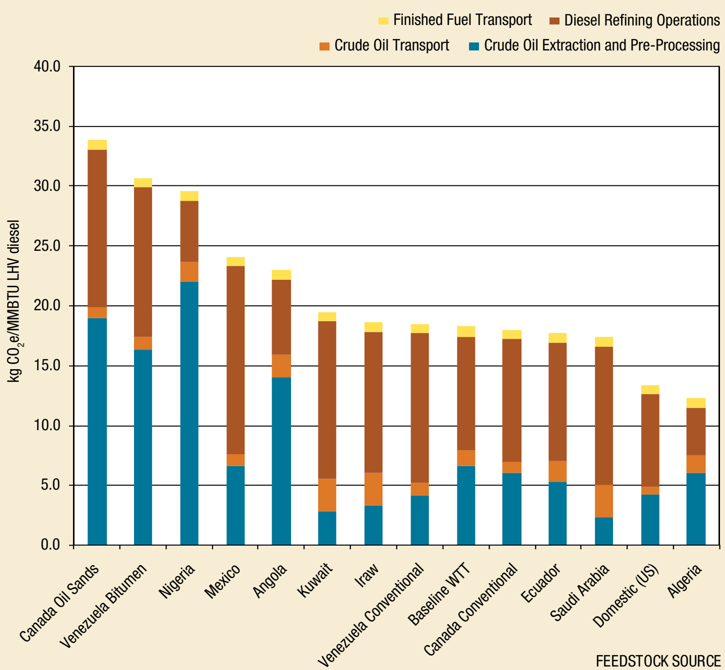
2.2.4 Refinery-to-Tank: Production of Gasoline Oils from SCO

The distillation and hydrotreating processes involved in refining SCO require heat sources, electrical power, and hydrogen production. The greenhouse gas intensity of refining operations depends on the quality of the crude oil being received at the entrance gate of the refinery. Refinery operations may account for 30-80 kg CO_2eq/bbl crude.

2.2.5 Tank-to-Wheels: Use of Gasoline in Transportation

The average heat content of crude oil is 5.8 MMBtu/bbl (compared to the heating value of a barrel of gasoline which is approximately 4.8 MMBtu) and the average carbon coefficient is 20.33 kg C per MMBtu. Given this, the CO_2 emissions associated with combusting one barrel of oil is approximately 430 kg. Most studies assume that CO_2 emissions associated with end user consumption is between 350 and 450 kg CO_2eq/bbl transportation fuel.

Figure 2.2.6-1 Well-to-Tank CO_2 Emissions (NETL, 2009)



2.2.6 Summary of Emissions: Well-to-Tank and Well-to-Wheel

The numbers described in previous sections cannot be directly summed because the results are not expressed on an equal basis, and reflect the different products (bitumen, SCO, transportation fuel) across the stages. A summary of life-cycle emissions for gasoline fuel on a Well-to-Tank basis is shown in Figure 2.2.6-1, reproduced from National Energy Technology Laboratory's evaluation of life cycle greenhouse gas emissions for imported crude oils.

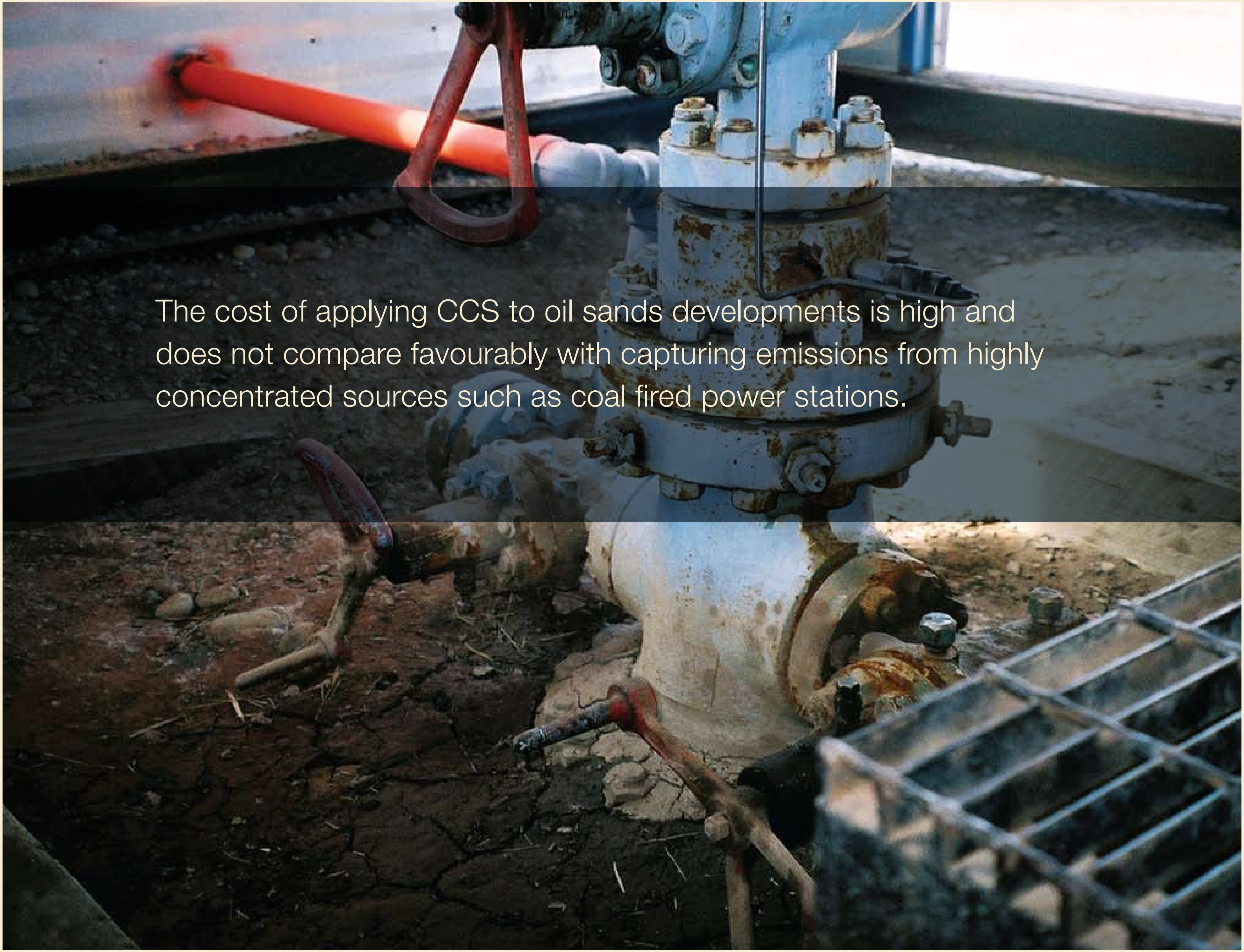
Production of fuels from the Canadian Oil Sands is significantly more carbon intensive than production of fuels from any other feedstock. Environment Canada's National Inventory Report on Greenhouse Gas Sources and Sinks in Canada 1990-2007, found that "oil sands mining, extraction and upgrading activities were about 1.7 times more GHG-intensive than conventional oil production in 2007" (Environment Canada, 2009).

However, of the 13 studies used by Charpentier et al., only GREET (2008) and GHGenius (2008) compared emissions from all three categories and both found much higher GHG intensities. GREET found surface mining to be twice as carbon intensive as conventional oil and in-situ to be 3 times as intensive. GHGenius found surface mining and in-situ to be 3 and 3.5 times as carbon intensive respectively. These figures are supported by a 2005 Pembina Institute study, which found well to refinery emissions from oil sands to be on average 3 times more carbon intensive than the average for conventional oil. A 2008 RAND Corporation report found them to be between 2.4 to 4.1 times more carbon intensive depending upon the method of extraction.

While Well-to-Tank emission for conventional oil accounts for approximately 20% of total Well-to-Wheels GHG emissions, for Canadian Oil Sands, Well-to-Tank emissions account for approximately 30% of total Well-to-Wheels emissions (Figure 2.2.6-2). On a Well-to-Wheel basis, several studies have estimated that transport fuels derived from oil sands are between 14 per cent and 40 per cent more GHG-intensive than conventional oil.

2.2.7 Export Upgrading / Export Refining

Bitumen is increasingly being sent to the United States where there is a much greater upgrading and refining capacity for heavy oil. This trend is supported by Statistics Canada which shows a 28% increase between 2003 and 2006 in the ratio of bitumen to synthetic crude oil production (Environment Canada, 2008). With many of the new projects being shelved until favourable market conditions return, one of the worries in the oil sector is that capacity in the US will be used to meet demands for upgrading and refining. While exporting activities to the US would lower GHG emissions on record in Canada, from a life cycle perspective, there is no net benefit – the emissions will still arise and will need to be dealt with.



The cost of applying CCS to oil sands developments is high and does not compare favourably with capturing emissions from highly concentrated sources such as coal fired power stations.

CARBON CAPTURE AND STORAGE

3.1 Carbon Capture

The greatest opportunity for carbon capture and storage (CCS) is at large point sources. There are four types of systems for carbon capture: capture from industrial process streams, capture from pre-combustion processes, capture from post-combustion processes, and capture from oxy-fuel combustion processes.

3.1.1 Types of Systems

Process Stream

Raw natural gas contains small amounts of CO_2 and this CO_2 together with H_2S is normally removed during the gas sweetening process. The most common gas sweetening operations use amine to absorb CO_2 and H_2S at high pressure, and regenerate the amine solution at low pressure and high temperature. In response to environmental regulations, these acid gas components released from regenerated absorbents have been compressed and injected in deep wells. Separation of acid components from natural gas streams is a well-established technology with a long history.

Pre-combustion

Pre-combustion capture of CO_2 would involve capturing the CO_2 from a synthesis gas ("syngas") stream. Such a stream may be produced, for example, from the gasification of heavy oils or coal. Steam reforming of methane is the most common method of producing hydrogen and normally done in the production of hydrogen. The process involves first a partial oxidation reaction to create carbon monoxide and hydrogen, followed by a water gas shift reaction to convert carbon monoxide to carbon dioxide, as shown below.

$$CH_4 + \tfrac{1}{2}\,O_2 \longleftrightarrow CO + 2H_2$$

$$CO + H_2O \longleftrightarrow CO_2 + H_2$$

The initial reaction is endothermic and typically occurs in the 800°C to 900°C range with the addition of a catalyst. The gas is then cooled and the waste heat it gives up is used to generate steam which is sent to the shift reactor. Hydrogen is subsequently separated from the carbon dioxide in the cooled gas; in older hydrogen plants the CO_2 is most commonly removed using an amine solvent or hot potassium carbonate. For the most part a nearly pure stream CO_2 has typically been rejected to the atmosphere. In more modern plants, pressure swing adsorption (PSA) is used for the recovery of H_2. In these systems, the CO_2 is in the regeneration stream together with some CH4 and H_2. This regeneration stream is often then used as a fuel in the reformer and after combustion the CO_2 is vented to atmosphere with the flue gas from the reformer. Pre-combustion capture of CO_2 is largely discussed in the context of integrated gasification combined cycles (IGCC), and reference systems exist for CCS in IGCC plants.

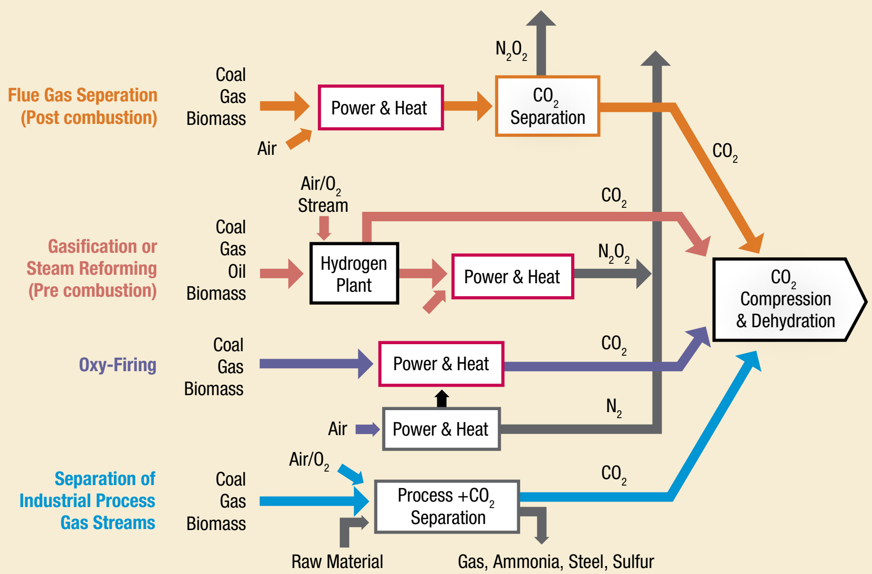
Oxy-fuel

An alternative to pre-combustion conditioning of the fuel is to condition the combustion environment. In oxy-fuel combustion, an enriched or nearly pure stream of oxygen is used rather than air in the combustion process. The elimination of nitrogen from the system reduces gas volumes, and results in a flue gas that is comprised mainly of CO_2 and H_2O. Combustion in a pure oxygen environment results in much higher flame temperatures and consequently, CO_2 and/or H_2O-rich flue gas is recycled to the combustion system to moderate temperature. Pure oxygen streams are normally produced by cryogenic separation of air, although new membrane and chemical systems are being developed that could reduce energy costs associated with producing a pure oxygen stream.

Post combustion

Flue gases containing CO_2 are referred to as post-combustion streams. These low concentration streams (<20% CO_2) are typically sent directly to the atmosphere. In a post-combustion capture system, the flue gas would be passed through a recovery system, discussed below, to capture most of the CO_2 and the remaining flue gases would be discharged to atmosphere.

Figure 3.1.1-1 Types of Carbon Capture Systems (IPCC, 2005)



3.1.2 Separation Technologies

Liquid Solvents

The most common method of CO_2 separation is through the use of liquid solvents, for either physical or chemical processes. In the case of physical solvents, organic liquids absorb CO_2 at high pressure and low or ambient temperatures. The solvent is typically regenerated by flashing to atmospheric or vacuum pressures. In some cases strip gas or heat with reflux can be used for regeneration. In the case of chemical solvents, the CO_2 undergoes a chemical reaction to form a weak salt in solution. The reaction is exothermic and is reversed with heat and low pressure. The circulation rate of the liquid absorbent typically varies directly with the amount of CO_2 being captured. A higher amount of CO_2 consequently results in more energy required for regeneration of the absorbent, and this adds a significant energy cost and energy efficiency penalty to a facility. As much as 70% to 80% of operational costs can arise due to solvent regeneration (Veawab, 2001). In order to be efficient, liquid absorbents must be able to operate under high CO_2 loading conditions and through many cycles without degenerating. Typical solvents for pre-combustion and post-combustion capture of CO_2 are shown Tables 3.1.2-1 and 3.1.2-2.

Table 3.1.2-1 Physical and Chemical Processes for Removal of CO_2 from Synthesis Gases (adapted from Maxwell, 2004)

PROCESS	TYPE	CHEMICAL	REGENERATION HEAT REQUIREMENTS	OPERATING PRESSURES (PHYSICAL SOLVENTS)	CO_2 SOLUBILITY@1ATM, 750F CC GAS/CC SOLVENT
aMDEA	Chemical	Activated Methyl Diethanolamine	42.5 (Two-Stage Regeneration)	—	N/A
BENFIELD	Chemical	Hot Potassium Carbonate	63-107 MJ/kmol CO_2	—	N/A
PRESSURIZED WASHING	Chemical	Monoethanolamine (MEA) or Diglycolamine (DGA)	88-209 MJ/kmol CO_2 for MEA	—	N/A
FLUOR SOLVENT	Physical	Propylene Carbonate	Pressure Only	850-1000 psi	3.3
PURISOL PROCESS	Physical	N-Methyl-2-Pyrrolidone (NMP)	Pressure Only	1000 psi	3.8
RECTISOL	Physical	Low Temperature Methanol	Pressure Only	400-1000 psi	
SELEXOL	Physical	Dimethyl Ethers of Polyethylene Glycol (DMPEG)	Flashing or Stripping (Uses Reboiler)	300-2000 psi	3.6

Table 3.1.2-2 Solvents Used for Postcombustion Removal of CO_2

PARAMETER	MEA	ECONOAMINE™	KS-1, KS-2, KS-3
TYPE	Chemical Solvent	Chemical Solvent	Chemical Solvent
CHEMICAL	15-20% MEA	30% MEA with inhibitor to resist corrosion	Sterically-hindered amines
VENDOR LARGEST CAPACITY	Kerr-McGee/ABB Lummus 800 tCO_2/d	Fluor Daniel 320 tCO_2/d Florida Power and Light Gas Turbine Flue Gas (2.8-3.1% CO_2, 13% 0_2)	KEPCO/Mitsubishi 200 tCO_2/d
REBOILER DUTY	180-251 MJ/kmol CO_2 (4100-5700 kJ/kg CO_2)	143 MJ/kmol CO_2 (3245 kJ/kg CO_2)	144 MJ/kmol CO_2 (3265 kJ/kg CO_2)

Figure 3.1.2-2 shows a matrix for the selection of processes for CO_2 removal. Because of the low pressure of post-combustion streams, chemical solvents are more appropriate than physical solvents for flue gases. At low pressures, chemical solvents are required to capture CO_2. Table 3.1.2-1 and Table 3.1.2-2 also show the significantly higher energy cost associated with capture CO_2 from low pressure flue gas streams compared to process streams.

Solid Sorbents

Systems using solid sorbents are usually comprised of a packed bed containing the solid sorbent. The gas stream flows through the bed and the sorbent is loaded with CO_2. The sorbent is regenerated with heat and/or by reducing pressure.

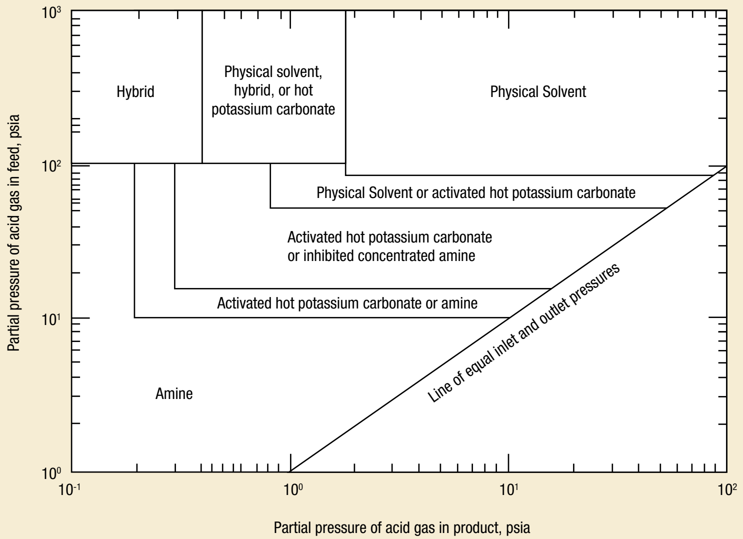
Membranes

Membrane technology uses pressure differentials to separate gases through a permeable surface. In order to operate effectively, membrane systems typically require high-pressure streams. Polymeric, metallic, and ceramic materials may have applications in separating CO_2 from H_2 in syngas streams or from other process streams. However, membrane technology is known to be expensive and much of the work on membrane systems for CO_2 separation is still in the R&D stage.

Cryogenic Processes

Cryogenic separations are done through extractive distillation with hydrocarbons. The Ryan-Holmes process is a commonly used means of separating CO_2 from natural gas components.

Figure 3.1.2-2 Selection of Process for CO_2 Removal (Faulkner, 2006)



Impact of Process Parameters

Operating parameters of a facility can have an impact on the technical and economic feasibility of carbon capture and storage systems.

Gas Flowrate – The gas flowrate determines the size of the absorber, which represents a significant portion of the capital cost of a recovery system. Carbon capture technologies can be applied to relatively large, continuous emission sources. Fugitive emissions and small venting streams do not have an adequate flowrate to warrant the capital and operating costs that would be associated with capturing CO_2. Further, compressing small streams to pipeline or injection pressure can be costly from a financial and an energy perspective.

CO_2 Partial Pressure – The partial pressure impacts the choice of solvent and the efficiency of solvent loading. Many of the sorbents currently being used in industry for CO_2 removal (e.g. amines, molecular sieves, physical solvents) operate at high pressure. The rich sorbents loaded with CO_2 are subsequently regenerated by reducing pressure and adding heat. The ability to use the differing equilibrium properties between a high pressure and low pressure system makes many of the sorbents much more efficient for CO_2 capture at high pressure than at low pressure.

CO_2 Removal – The specification for amount of CO_2 removed can have a significant impact on the selection of the technology. Requirements for higher recovery (i.e. lower concentrations remaining) correspond to taller absorption columns and higher energy penalties.

3.1.3 Transmission

Subsurface storage of CO_2 typically occurs at depths greater than 800 m. CO_2 separated from process or flue gas streams, therefore, must be compressed not only for transmission, but also for subsurface injection. Given the depths at which CO_2 is stored, it is compressed into its supercritical or dense phase. Depending on the distances to be transported and terrain, repumping and compression stations may be required enroute, incurring further energy penalties (McCoy, 2005). Trials combining CO_2 as a transport medium for other value added products are currently underway (PTAC, 2009) and have the potential to reduce transportation costs.

3.2 Carbon Storage

3.2.1 Criteria for Carbon Storage

No full scale integrated CCS system yet exists in connection with oil sands developments. The technology, and even the science, is at a very early stage. However, research is ongoing and various options are being considered, as outlined below.

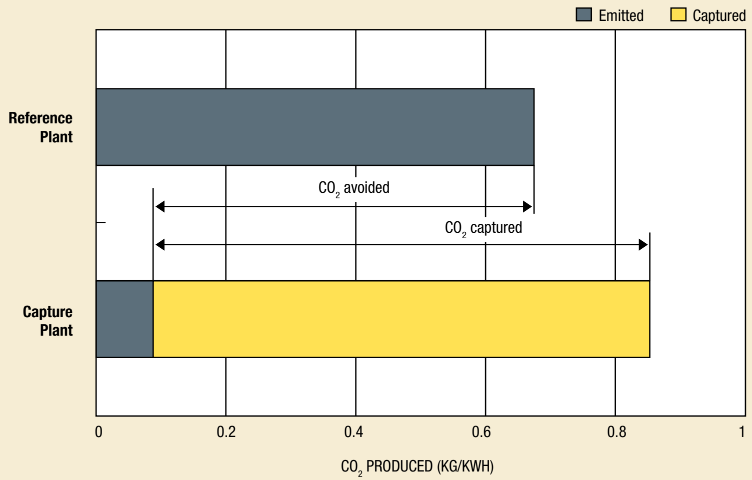
Though the terms storage and sequestration are at times used interchangeably, more accurate is to differentiate on the basis of whether the CO_2 is fixed on a permanent basis, for example by reaction into a mineral form, rather than stored often in a gaseous or liquid state with consequent larger potential for leakage (Griffiths, 2005). When estimating CO_2 emissions avoided, it is further necessary to differentiate that amount from the amount captured, as these represent different amounts due to the energy consumption of the CCS stages, shown in Figure 3.2.1-1.

3.2.2 Terrestrial/geological

Underground storage of carbon dioxide has some history as a result of a large number of acid gas projects and projects for enhanced oil recovery (EOR). The concept as a greenhouse gas mitigation strategy was first proposed in the 1970s, but it was only in the early 1990s that focused research was pursued.

Theoretically, if the CO_2 is injected below low-permeability structures, the CO_2 is physically trapped stratographically and structurally. Once injected into reservoir rock, CO_2 permeates, displacing some of the original fluid, conversely, the use of CO_2 injection can boost production, extend the production life of an oil and gas reservoir and create GHG emissions anew. Research exists to suggest that CO_2 injected into semi-depleted oil and gas reservoirs can be retained at a rate of 20-67% with the remaining CO_2 emerging from the well with co-products from which it can be separated and recycled with only an energy penalty. However, monitoring over time has been extremely limited given the need for CO_2 to be sequestered for at least decades.

Figure 3.2.1-1 CO_2 Captured and Avoided (Griffiths, 2005)



As EOR has the potential to increase net atmospheric carbon emissions because of improved recovery of fossil-fuels in addition to relatively high leakage rates, EOR is often not considered sequestration. But, as EOR may reduce land disturbances when compared to new explorations. As EOR is typically the lowest cost option (discussed in more detail later) it can contribute to decreasing research and development costs for all potential future users of CCS, including biomass sources.

The EOR market is relatively small compared to the total volume of capturable CO_2 in western Canada, so other storage options are needed. The total size of the EOR market depends on many factors (including the price of CO_2 and the price of oil) but preliminary estimates indicate that 450 Mt of capacity may be currently available. This equates to less than 10 Mt/year of storage for 50 years (Bachu in ecoEnergy, 2008), and oil sands operational emissions could be in the region of 127 to 140 Mt/year as early as 2020. It is claimed that the Western Canada Sedimentary Basin (WCSB) has a significant potential for carbon storage. Basin suitability and sources of CO_2 emissions are shown in Figure 3.2.2-1.

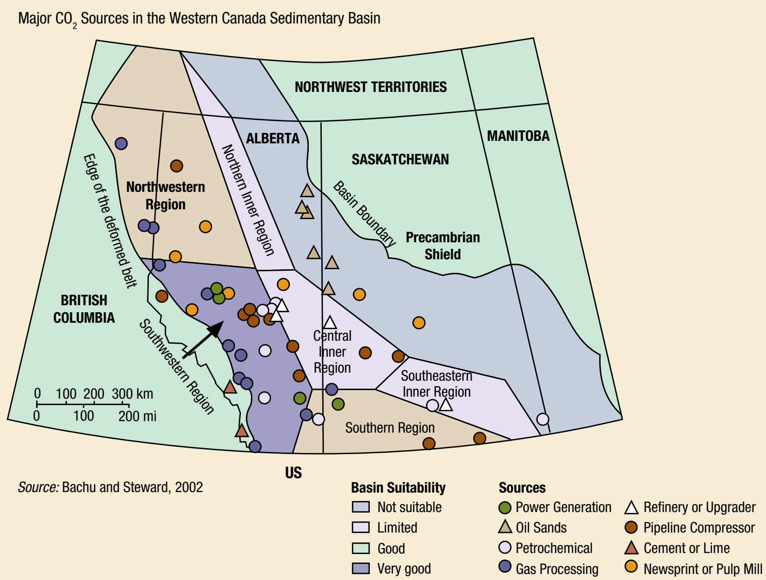
3.2.3 Aquifer

Deep saline aquifers are considered the most plausible long-term storage locations for compressed CO_2 by oil sands developers. Theoretically, CO_2 injected into deep saline aquifers will be trapped hydrodynamically. Some of the CO_2 will dissolve, but the rest forms a plume that lies at the top of the aquifer: in typical aquifer storage conditions (greater than 1000 m), the density of CO_2 will be about two-thirds that of brine, which means that the CO_2 would be buoyant and a driving force for escape would exist.

3.2.4 Solid

Solid sequestration of CO_2, also known as mineral carbonation or mineral sequestration, involves the reaction of carbon dioxide with metal oxide to form insoluble carbonates. The most attractive metals for mineral carbonization are calcium and magnesium. Solid sequestration can occur as an ex situ chemical process or an in situ process involving CO_2 injection in geological formations rich with silicate or in alkaline aquifers. The technology for mineral carbonation is still in the early stages of development (IPCC, 2005).

Figure 3.2.2-1 Basin Suitability and Sources for CCS (Reynen, 2008)



3.2.5 Tailings ponds

Carbon dioxide could both reduce the amount of calcium required for the consolidation process and at the same time scavenge excess calcium as a calcite precipitate. The consolidated tailings (CT) process (commercialised at Suncor) involves the transfer of mature fine tailings (MFT), addition of gypsum, and mixing with coarse tailings to create a material, which can be eventually reclaimed as a soil. During transfer of MFT, bubbling CO_2 could be used to extract residual bitumen from the MFT, while absorption of CO_2 in the MFT would result in favourable properties relative to CT production.

This manipulation of the MFT properties using CO_2 could result in a reduction of the gypsum requirement and ultimately reduce the ionic loading in the recycle water to the extraction process. Total CO_2 capture is approximately 100X greater for preliminary trials and depending upon the rate at which physically sequestered CO_2 becomes chemically sequestered as carbonate and bicarbonate, these results suggest that chemical sequestration would be at a minimum 1200t/Mt for a conventional CT deposit (R, D&D Project Database). It should be note that this concept is still in the very early stages of development.

Table 3.2.6-1 Proposed Screening Criteria for CO_2-EOR and CO_2 Sequestration (Kovscek, 2002)

PARAMETER	POSITIVE INDICATORS	DESCRIPTION
RESERVOIR PROPERTIES		
Average oil saturation (So) and porosity (ø), Soø	> 0.05	Reflective of the oil remaining per volume of a rock. The larger this factor, the more attractive the project due to the volume of oil in place.
Average permeability (k) and thickness of the oil-bearing zone (h), *kh*	> 10^{-14}-10^{-13}	Amount of oil a well can deliver is proportional to this factor
Pre pressure gradient (kPa/m)	< 17.4	Injection of CO_2 should be controlled so the pore pressure does not exceed approximately this value. Reservoirs containing hydrocarbons to be economic have a pore pressure gradient less than this; used as an indicator of potential for leakage
Location	Divergent basin	Convergent basis are subject to plate convergence and subduction, and hence earthquakes. Divergent basis are generally associated with more stable tectonics
Seals	Adequate characterization of caprock, minimal formation damage	Avoid areas prone to fault slippage
OIL PROPERTIES		
Density	> 22900	Most efficient production of oil by EOR comes from miscible displacement of light oils
Viscosity	< 5	Most efficient production of oil by EOR comes from miscible displacement of light oils
Composition	High concentration of C_5-C_{12}, relatively few aromatics	Promotes miscibility of oil and CO_2
SURFACE FACILITIES		
Corrosion	CO_2 can be separated to 90% purity in cost effective manner	Economic parameter
Pipelines	Anthropogenic CO_2 source is within 500 km of a CO_2 pipeline or oil filed.	Economic parameter
Synergy	Preexisting oil production and surface facilities expertise	Economic parameter

3.2.6 Oceanic

Oceanic storage of CO_2 involves injection directly into the ocean or on the sea floor. Below a depth of 3 km, CO_2 is denser than sea water. Over the past 200 years, oceans have taken up approximately 40% of total anthropogenic CO_2 emissions, and because the CO_2 resides in the upper ocean, it has resulted in a decrease in pH of about 0.1 at the ocean surface (IPCC, 2005).

Little is known regarding the CO_2 impacts on marine organisms or the ecosystem. Experiments have shown that marine organisms are adversely impacted by added CO_2, and studies on organisms living near the ocean surface have shown lower rates of calcification, reproduction, growth, circulatory oxygen supply and mobility, and increased mortality; in some cases, these effects are seen in response to small increases in CO_2 (IPCC, 2005). Given the requirement to be proximal to oceanic shores, oceanic sequestration of CO_2 is not likely to be pursued for oil sands operations. Table 3.2.6-1 shows factors that must be considered prior to pursuing CCS for enhanced oil recovery and for sequestration.

3.2.7 Stability and Impact of Carbon Storage

The Weyburn Oilfield

The Weyburn Oilfield is the largest geological CO_2 storage project and has been studied by various research groups, including the International Energy Agency. Research has looked at long-term safety and performance of CO_2 storage; definition of baseline hydrogeological and hydrochemical conditions; and changes resulting from CO_2 injection.

Initial data has shown that CO_2 injection in Midale beds led to rapid reactions with carbonate dissolution, and some precipitation of gypsum. Three CO_2 flooding experiments were completed on Midale Marly samples. Sample porosity and gas permeability increased while calcite and dolomite underwent significant corrosion and some disintegration was observed. Microseismic monitoring has been completed, and microseismic events were recorded with the microseismicity being possibly related to small fractures produced by injection driven fluid migration within reservoir. No evidence has been observed so far of any leaks of injected CO_2 at surface (Riding, 2006), although it has to be noted that the research project only commenced in 2000.

Other large projects

Other large projects globally include the In Salah CCS project in Algeria where approximately 1 Mt/year of carbon dioxide from a natural gas stream is re-injected, and two deep sea projects in Norway that inject into deep formations under the sea.

WEYBURN SEQUESTRATION PROJECT

The Weyburn oilfield began operation in 1954 and produced about 18,200 barrels per day. The field comprises 10% of EnCana's oil production. In 2000, EnCana agreed to use the Weyburn field as a demonstration project for CO_2 storage and enhanced oil recovery. Approximately 6000 tpd of CO_2, produced from a synfuels plant in North Dakota is transported via a 325 km pipeline to the Weyburn field for enhanced oil recovery, and production has been boosted by 25%. The Weyburn Project is the world's largest geological CO_2 storage project and is studied intensively by the International Energy Agency. Phase I of the project (2000-2004) focused on proving the ability to store CO_2 over the long-term and demonstrating predictive, monitoring, and verification techniques. Phase II of the project (2005-2010) is focused on developing an understanding of oil wellbore integrity over hundreds of years of CO_2 storage and developing practical protocols to guide implementation of CCS projects. Phase II will also develop a Best Practices Manual for site selection, monitoring and verification, wellbore integrity, and performance assessment, and inform the development of regulatory and policy frameworks.

3.3 Maturity of Carbon Capture and Storage

Investment into technologies for carbon capture and storage is increasing rapidly. Capturing CO_2 from process streams or combustion streams is a well-understood operation. Compression of CO_2 and injection into transportation pipelines is also well understood. Apart from Enhanced Oil Recovery, however, long-term storage of carbon dioxide is still in the early phases. Table 3.3-1, reproduced from the IPCC Special Report on CCS, summarizes the state of technology for each of the components and options with a CCS system.

Table 3.3-1 Current Maturity of CCS System Components (IPCC, 2005)

CCS COMPONENT	CCS TECHNOLOGY	RESEARCH PHASE	DEMONSTRATION PHASE	ECONOMICALLY FEASIBLE UNDER SPECIFIC CONDITIONS	MATURE MARKET
CAPTURE	Post-combustion			X	
	Pre-combustion			X	
	Oxyfuel combustion		X		
	Industrial separation (natural gas processing, ammonia production)				X
TRANSPORTATION	Pipeline				X
	Shipping			X	
GEOLOGICAL STORAGE	Enhanced Oil Recovery (EOR)				X
	Gas or oil fields			X	
	Saline formations			X	
	Enhanced Coal Bed Methane recovery (ECBM)		X		
OCEAN STORAGE	Direct injection (dissolution type)	X			
	Direct injection (lake type)	X			
MINERAL CARBONATION	Natural silicate materials	X			
	Waste materials		X		
INDUSTRIAL USES OF CO_2					X

* CO_2 injection for EOR is a mature market technology, but when this technology is used for CO_2 storage, it is only 'economically feasible under certain conditions'.

3.4 Economics of CCS

Hands-on CCS technology experience at scale is very limited globally, and therefore cost estimates, technology selection choices, and performance expectations all have a high degree of uncertainty.

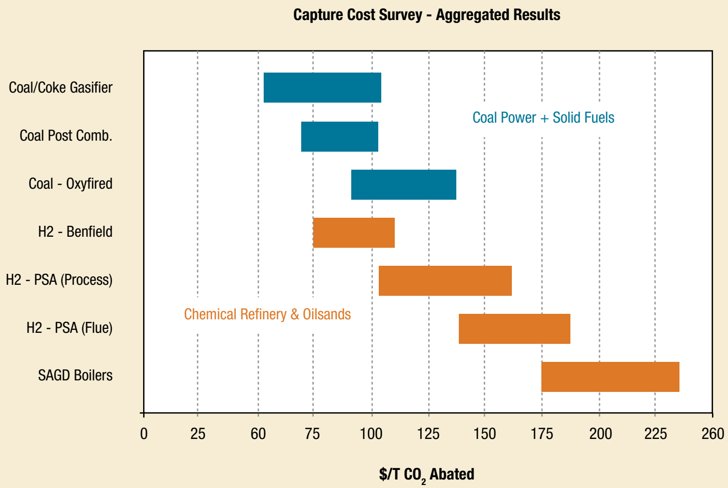
In March 2009, the Alberta Carbon Capture and Storage Development Council published its final report 'Accelerating CCS implementation in Alberta'. It found that CO_2 capture represents 70 to 90 per cent of the overall costs of the CO_2 capture, transport and storage sequence. In addition, it found capture is the step with the least amount of actual technology application and, accordingly, it is the area where there is significant cost uncertainty.

To better understand the cost of capture, it surveyed 27 companies known to be interested in CCS. Data was collected on more than 20 facility concepts from 10 companies. Cost estimates were \$75 to \$235 per tonne of CO_2 for chemical, refinery and oil sands capture, with SAGD boiler capture within the \$175 to \$235 range.

Using this data, a cost curve was generated for all capturable CO_2 emissions in Alberta for the year 2020. The overall capture costs ranges from: \$60 to \$150 per tonne for coal fired power stations and oil refining/upgrading; \$110 to \$240 per tonne for oil sands upgrading; and \$200 to \$290 per tonne for SAGD and gas fired sources.

The Government of Alberta announced a \$2 billion CCS fund in 2008 to help ensure that a first wave of three to five CCS demonstration projects was initiated. The Alberta CCS Development Council's final report estimated that an investment of between \$1 to \$3 billion per year from the governments of Alberta and Canada will be required to promote further CCS projects after the first wave of demonstration plants.

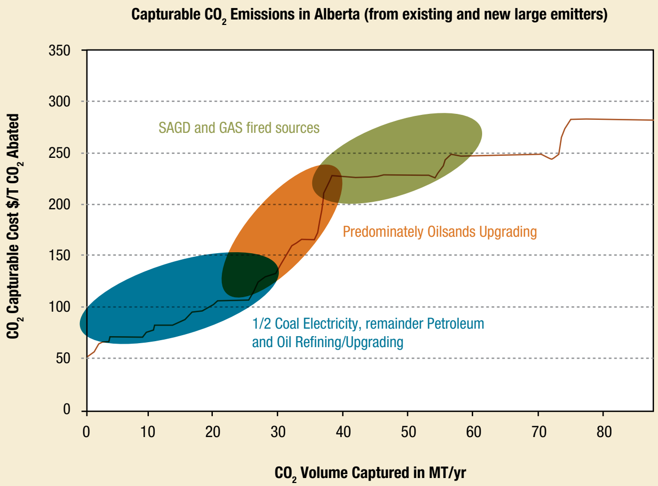
CO_2 Captured – Cost Estimates



Note:
- Based on over 50 interviews and 20 different facilities. Cost Ranges due to geographic, technical and greenfield vs. retrofit considerations
- Excludes pipeline, storage costs, credit from EOR sale, avoided offset purchase
- Capital costs in 2008 C\$. Operating costs levelized at 2008 real \$ cost (10% time value discount)
- "CO_2 Abated Cost" includes cost penalty for make up production and incremental CO_2 emissions from energy use (fuel and electricity)

Source: Ian Murray and Co. Ltd.: Alberta CO_2 Capture Cost Survey and Supply Curve 2008

CO_2 Captured Cost Curve



Note:
- Includes all facilities estimated to be operating in Alberta by 2020 (existing and yet to be built)
- Reflects only capture costs, not pipeline or storage costs, nor credit from EOR, sale, nor avoided offset purchase Capital costs in 2008 C\$. Operating costs levelized at 2008 real \$ costs for fuel and operatic
- "CO_2 Abated Cost" includes penalty for make up production and incremental CO_2 emissions from energy use (fuel and electricity)

Source: Ian Murray and Co. Ltd.: Alberta CO_2 Capture Cost Survey and Supply Curve

The most optimistic forecasts for CCS in the oil sands are reductions of between 30% and 50% by 2050.

PERSPECTIVES ON CCS

4.1 ENGOs

4.1.1 The Pembina Institute

The Pembina Institute is cautious about CCS, viewing it as "…one of a number of potentially effective technologies for reducing GHG emissions on the scale required to combat catastrophic climate change" (Pembina, 2009). Their position recognises that "even if CCS is acceptable as a means of storing CO_2, capture is only realistic from large point sources. Thus only a portion of total emissions would be available for storage." (Griffiths et al, 2005).

Recognising the global realities, Pembina affirms that CCS provides a technically feasible option to manage a portion of the CO_2 waste from this growth in fossil fuel use, especially in the rapidly growing economies of Southeast Asia (including China and India). Past research papers have encouraged the oil sands operators to implement CCS in order to reduce their impact without dwelling on the small portion of total carbon contained in the product this could account for. The Pembina Institute believes that development and deployment of CCS in Canada should be conditional upon a massive scale-up of energy efficiency and low-impact renewable energy production; application of CCS in regional contexts; implementation of a strong regulatory framework; a fair distribution of investment between taxpayers and polluters, with polluters quickly shouldering the full cost of CCS deployment; establishment by government of a price on emissions high enough to stimulate the adequate deployment of low/no emission technologies, including CCS where appropriate; and an increase in public education and awareness in order for CCS to be more widely accepted as a viable technology within a portfolio of solutions for reducing GHG emissions.

4.1.2 Sierra Club

The Sierra Club's (SC) position on CCS is less favourable than that of Pembina. SC has focused on the broader energy implications or investing heavily into a technology that does not permanently address the link between energy consumption and carbon emissions. SC emphasises the uncertainties and gaps in knowledge with respect to CO_2 retention in geological storage, and in particular, the uncertainties in long-term impacts. SC, therefore, encourages the focus of resources on other means of reducing carbon emissions, particularly in light of the expense and energy-intensiveness of CCS (Sierra Club, 2008).

"As a nation, we should not unwisely depend on geologic sequestration to solve all of our problems. Nor should we wait until sequestration is commercially available and cost-effective before moving to make deep cuts in carbon emissions with reliable tools like energy efficiency and renewable energy." **– Sierra Club**

4.1.3 Greenpeace

Greenpeace has been strongly opposed to CCS, calling it a 'pipe dream' and opposing taxpayer subsidies of CCS efforts. In its publication, "False Hope: Why Carbon Capture and Storage Won't Save the Climate," Greenpeace underscores that CCS is a technology which has not been demonstrated commercially, and is expected to have an extremely high cost. To support their position, a more recent study was commissioned with the European Renewable Energy council details alternatives to an energy future with CCS. Economic modelling for the study was performed by the German Aerospace Centre (DLR) using International Energy Agency forecasts for a baseline and proven technologies for the alternative scenario. It attempted to demonstrate "how Canada can, with off-the-shelf technology, cut carbon dioxide emissions from the Canadian energy sector 40% below 1990 levels by 2020 and 82% by 2050." (EREC 2009)

4.1.4 Environmental Defence

Environmental Defence has opposed oil sands developments, most prominently through its publication: Canada's Toxic Tarsands: The Most Destructive Project on Earth. In that document, Environmental Defence states that "Tar Sands companies know how to capture and store their carbon emissions underground or under the sea. The technology exists. They aren't doing it because it's more profitable to use the atmosphere as a free waste dump until the Canadian government requires them to stop." Environmental Defence advocates for a hard cap on emissions from the tar sands, suggesting that this would lead to companies having to figure out carbon capture and storage without public subsidies, or forego future operations. A higher price on carbon would also close the gap more quickly (Hatch and Price, 2008).

4.1.5 WWF

WWF acknowledges that carbon capture and storage has the potential to reduce greenhouse gas emissions as part of a broader suite of measures. The Climate Solutions report found that renewable energy and energy efficiency could deliver most of the necessary reductions in emissions, and that the use of fossil fuels with the capture and storage of the resulting carbon emissions could also play a significant role as a bridge to a truly low-carbon, sustainable energy system (WWF, 2007).

This is a qualified support. CCS technology has not yet been proven at scale and as a result there are legitimate concerns regarding the cost of CCS compared to other carbon-cutting alternatives including: the permanence of carbon storage, the potential biodiversity impacts, the full energy balance of CCS operations, and how quickly it can be scaled up in order to achieve significant greenhouse gas reductions. Additionally, the WWF has a policy not to support carbon capture when it is primarily part of a public relations strategy intended to justify business as usual rather than reduce emissions (WWF-UK, 2008).

4.2 Intergovernmental Organizations

4.2.1 Intergovernmental Panel on Climate Change (IPCC)

Working Group III (WGIII) of the IPCC was charged with responsibility of assessing scientific, technical, environmental, economic, and social aspects of CCS. The assessment was to include the maturity of technology, the technical and economic potential to contribute to mitigation of global warming, and the costs for CCS.

WGIII found that CCS has some potential to reduce overall mitigation costs and increase flexibility in achieving reduction targets for greenhouse gases and that CCS in the portfolio of options could play a role in achieving stabilisation goals. Post-combustion capture of CO_2 from power plants is economically feasible under certain conditions and the technology required for pre-combustion capture is already widely applied.

The IPCC Special Report on CCS noted that “the technical maturity of specific CCS system components varies greatly” and that as of mid-2005 there had been just three commercial projects linking CO2 capture and geological storage. Moreover, that “CCS has not yet been applied at a large (e.g. 500 MW) fossil fuel power plant, and that the overall system may not be as mature as some of it components”.

4.2.2 United Nations Principles for Responsible Investment

A recent UN-PRI sponsored letter to oil sands operators, from over 40 international institutional investors with interests in Alberta’s oil sands and representing over $3 trillion of assets, stated: “Oil sands present a different and challenging set of economic, political, environmental and social risks to conventional oil that, without comprehensive and rapid mitigation, threaten their viability as long term investments”. With regard to GHG emissions, the letter requested a plan from each operator for reducing emission intensity per barrel to levels approaching the average of conventional sources presently, no later than 2020 and using an accessible methodology that encompasses all GHG emissions in the production chain prior to combustion, including those resulting from the destruction of boreal ecosystems and tailings ponds.

4.3 Government

4.3.1 Environment Canada

Environment Canada’s “Turning the Corner” plan sets out the Federal Government’s framework for reducing emissions from the Canadian economy. It aims to reduce greenhouse gas levels to 20% below 2006 levels by 2020 which is approximately 3% below 1990 emissions baseline upon which the Kyoto agreement is based. The IPCC recommends cuts of 25-40% by 2020 from 1990 levels and Canada’s commitment for the current period to 2012 is 6% below a 1990 baseline.

The Federal plan assumes that CCS technologies will soon be mature and requires oil sands projects starting from 2012 and onwards to effectively implement CCS technology or “other green technology to drastically reduce greenhouse gas emissions.” by 2018. Research and development funding announced in the latest budget supports CCS research, however, the plan has not passed into law at the time of writing.

4.3.2 Alberta Energy / Alberta Government

Their strategy – 'the Alberta Climate Change Strategy' – identifies three themes for which action will be taken: implementation of CCS, greening energy production, and conserving and using energy efficiently. CCS is viewed as a significant contributor to Alberta's long-term climate change strategy and it is claimed that up to 70% of Alberta's potential reductions will come from CCS. At the same time, the Alberta government has recognised that it will take 15 years to commercialise CCS technology. The plan is often criticized for failing to place hard targets on emissions, opting for intensity based targets that have the potential to result in overall increases if future targets fail to account for growth in the industry. The current target of a 50% reduction from business-as-usual levels by 2050, for instance, has been calculated to result in a 31% increase relative to a 1990 baseline in absolute terms (EREC 2009).

To encourage development of CCS technologies in Alberta, the provincial government has put forward $2 billion in funding for research and demonstration projects. In October 2009, the Alberta government announced $745 million towards the Quest project of Royal Dutch Shell Plc, which aims to capture and store up to 1.2 million metric tonnes of CO_2 per annum at it's Scotford upgrading facility. The federal government has committed an additional $120 million, for a total of $865 million in public subsidy for a project with an estimated capital cost of $1.3 billion. Shell has not committed to the project, and will decide within the next two years as to whether or not they will proceed. If the project goes ahead, it would be operational in 2015 at the earliest.

4.3.3 ecoENERGY Carbon Capture and Storage Task Force

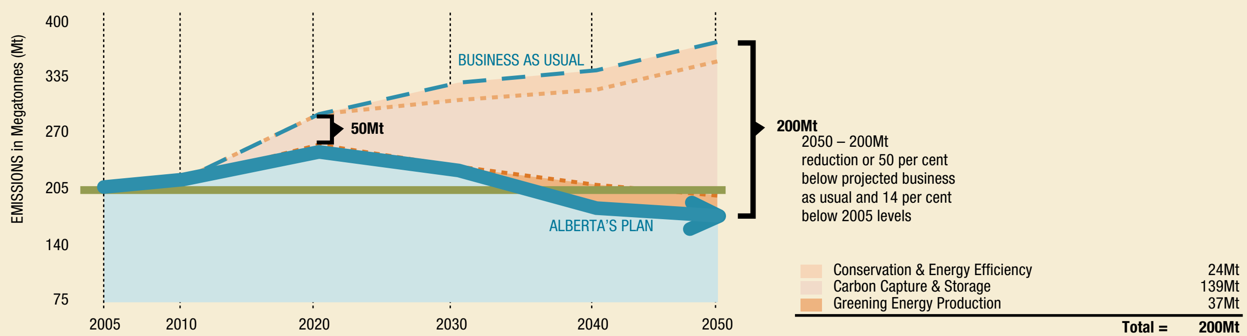
Established by Alberta and Federal Governments in March 2007, the ecoEnergy Carbon Capture and Storage Task Force is mandated to provide advice on how industry and government can together facilitate CCS opportunities. The Force believes that CCS can facilitate up to 40% reduction in the CO_2 emissions expected in 2050, and that CCS can play a role in breaking the link between energy use and GHG emissions.

Their view is that if Canada acts too aggressively to reduce GHG emissions in the near term it risks putting its industrial base at a competitive disadvantage. By the same token, however, if Canada moves too slowly it may also hurt its competitiveness as the rest of the world turns to standards that make GHG-intensive energy sources less viable. The taskforce emphasises that competitiveness of the domestic fossil energy sector hinges on using CCS to satisfy growing GHG reduction obligations while continuing to develop these fossil energy resources.

The Task Force recognizes that there are challenges in implementing CCS, in particular that lower-concentration or smaller emission streams are more costly to capture because of the additional capital and operating costs (including energy use) associated with capture, separation, and purification processes (ecoEnergy Carbon Capture and Storage Task Force, 2009).

"Oil sands are the fastest growing sector for domestic GHG emissions so that there are real opportunities for reductions. However, oil sands operations are diverse (geographically and technically) and only a small portion of the CO_2 streams are currently amenable for CCS due to both the size of emissions streams and the concentrations." **– ecoEnergy CCS Task Force**

Figure 4.3.3-1 Contribution of CCS to Alberta's Commitments to Greenhouse Gas Emissions



4.4 Industry

4.4.1 Associations

ICO$_2$N

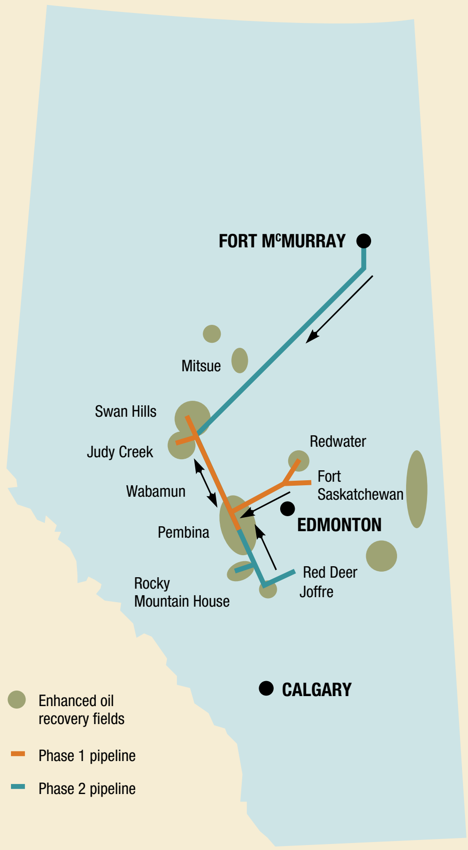
The Integrated CO$_2$ Network (ICO$_2$N) is an alliance of 15 of Canada's largest GHG emitters. The alliance alone accounts for more than 100 Mt of CO$_2$emissions and includes more than 60% of emissions from electricity generation and more than 95% of emissions associated with oil sands production. The Network views CCS as an opportunity for Canada to be a global leader. Amongst the challenges for companies to engage in CCS are an appropriate public policy framework and an infrastructure through which the investment costs for establishing the technology can be shared between the private and public sectors, which would likely take the form of public subsidies for CCS development and implementation.

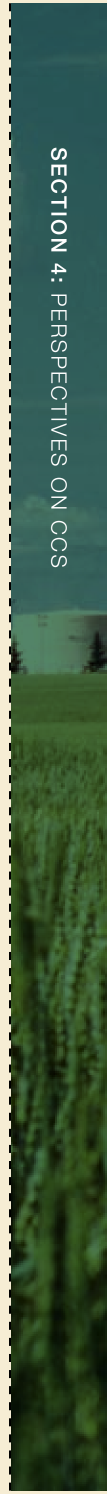
ICO$_2$N was formed to explore the viability of a large-scale Canadian carbon dioxide capture, transportation, and storage network. In December 2007, ICO$_2$N released a report, Carbon Capture and Storage: a Canadian Environmental Superpower Opportunity, which detailed the requirements to implement the system in Canada.

The report targets large sources of industrial emissions in Alberta, including coal-fired electrical generation and energy production. A portion of the captured CO$_2$ would be used for enhanced oil recovery in the conventional crude oil industry, and the balance would be sequestered in geological formations.

ICO$_2$N has proposed pipelines to reduce the transport cost of CO$_2$ from the major sources at power facilities to appropriate storage sites shown in Figure 4.4.1-1. This is a fundamental infrastructure requirement for CCS to be considered on a large scale, and includes the site of major oil sands upgrading facilities in Fort Saskatchewan in Phase 1. In terms of the proportion of CO$_2$ emissions from oil sands production activities that can be captured, ICO$_2$N's Director of Strategy and Policy has stated: "Oil sands operations that install current CO$_2$ capture technology in the best process locations can expect to reduce CO$_2$ emissions from all mining and upgrading operations from 10% to 30%. As technology improves, cost reductions will allow CCS to be viable in other areas of oil sands plants, taking overall reduction levels to the 30% to 50% range." (Beynon, National Post, March 9, 2009).

Figure 4.4.1-1 ICO$_2$N Proposed CO$_2$ Pipeline





ICO_2N PARTICIPANTS

Agrium Inc.
Air Products Canada Inc.
Canadian Natural Resources Ltd.
Chevron Canada Ltd.
ConocoPhillips Company
Devon Energy
EPCOR
Husky Energy Inc
Imperial Oil Ltd.
Keyera
Nexen Inc.
Opti Canada Inc.
Shell Canada Energy
Sheritt International Corporation
StatoilHydro Canada Ltd.
Suncor Energy Inc.
Syncrude Canada Ltd.
Total E&P Canada Ltd.
TransAlta Corporation

Canadian Association of Petroleum Producers

The Canadian Association of Petroleum Producers (CAPP) represents 130 companies that explore for, develop, and produce natural gas, natural gas liquids, crude oil, oil sands, and elemental sulphur throughout Canada. The member companies account for more than 95% of Canada's natural gas and crude oil. Although CAPP supports the actions of its members in exploring CCS, the organization does not have any flagship projects. The association has previously said that "Canada should look beyond an emerging technology of burying greenhouse gases underground if it wants to help tackle climate change" (Gardner, 2008); however, more recent statements have focussed on ensuring a complicit regulatory framework including tax deductibility of GHG reduction initiatives including CCS, an expanded capital cost allowance to include CCS expenditures, and increased direct public funding of new and developmental CCS projects.

4.4.2 Private Sector Companies

Canadian Natural Resources Limited (CNRL)

Canadian Natural Resources Limited (CNRL) CNRL's Horizon project focuses on maximizing heat integration and using cogeneration to meet steam and electricity requirements and reduce greenhouse gas emissions. It is claimed that the design of the hydrogen production facility for the Horizon initiative enables CO_2 capture and the Project will, at a future date, incorporate various other advancements in technology to minimize greenhouse gas ("GHG") emissions including the research, development, and implementation of a process to sequester CO_2 into tailings (CNRL, 2007). CNRL has applied for a part of the Alberta Government's $2 Billion dollars in funding for CCS projects in support of their plan to sequester CO_2 into tailings ponds.

Shell Canada

As part of its sustainability plan, Shell targets to have CO_2 emission levels that are in the top 25% of similar facilities. In order to achieve this, it looks to greater energy efficiency and further progress on CCS.

Shell, on behalf of the Athabasca Oil Sands Project (a joint venture with Chevron and Marathon Oil), has also submitted for public disclosure plans to refit all three hydrogen processing units at the Scotford upgrader to enable the relatively pure CO_2 stream to be compressed for sale to EOR projects commercially or for injection for storage within 60km of the plant. The project would involve the capture of 1 million tonnes of CO_2 annually which would otherwise be vented to the atmosphere and storing it at a depth of 2000 – 2500 metres in the Cambrian Basal Sands. Depending on the results of their test wells, Shell expects to apply for regulatory approval in 2009 and if successful then construction and commissioning would place startup approximately 6-9 years from regulatory approval (Shell 2008). Shell has successfully applied for the Alberta Government's CCS funding pool for the Quest project.

Imperial Oil

In spite of the current economic uncertainties, Imperial Oil recently announced that it would be proceeding with the Kearl oil sands project. The company is not planning to include carbon capture and storage.

Syncrude and Suncor

Syncrude claims to be working with other companies to develop CCS technology and its position is aligned to that of ICO_2N (Syncrude, 2007). Suncor's has publicly committed to being a leader in the development of renewable energy and biofuels and also "to bring a carbon capture and storage initiative closer to implementation." Syncrude, along with Suncor and several other major oilsands player have not, however, decided to avail themselves of 2 Billion dollars in funding offered by the government of Alberta for CCS demonstration projects (Alberta Energy 2009).

"Though CCS has the potential for dramatically reducing GHG emissions, it is currently extremely energy intensive and very expensive. In addition, clarification is also needed around developing climate change regulations in many areas including investment, readiness, legal ownership of storage and future liability." **– Petro-Canada**

Petro-Canada

In response to the federal government's proposal for carbon intensity targets in 2010 and for its mandated carbon capture and storage, Petro-Canada has stated that "This solution poses some risks in that CCS has never been implemented on the scale proposed, nor have certain key implementation details been discussed." (Petro-Canada, 2009). Petro-Canada claims to be studying to build infrastructure to capture and store CO_2 and is engineering the hydrogen plant at its proposed Sturgeon Upgrader to be carbon sequestration ready (Petro-Canada, 2009).

StatOilHydro

Based in Norway, StatoilHydro is an oil and gas company that is expanding internationally. The company has investments in the oil sands region in Alberta. StatOilHydro plans to produce using SAGD, and recognizes that "the process is energy-intensive and that the carbon dioxide emissions will be much higher than from conventional oil production." (StatOilHydro, 2008). In 2008, StatOilHydro Canada established a climate change group with the main tasks of establishing a strategic plan for CO_2 and ensuring implementation of corporate climate change policies in Canadian projects. The strategic plan calls for energy efficiency measures, technology development, generation and use of offsets and evaluation of CCS (StatOilHydro, 2008). StatOilHydro hopes to participate in a CCS project with other industry players in Alberta. StatoilHydro is a member of ICO_2N and has experience in CCS including though its Sleipner fields in the North Sea and its activities in Salah in Algeria.

4.5 Public Perceptions of CCS

Two major surveys have been conducted to gauge public opinion of CCS in Canada. The first study, carried out in 2005 by researchers at Simon Fraser University in British Columbia was administered by Synovate and involved 1972 respondents, including 775 from Alberta and Saskatchewan. The second survey, conducted by Canadian Ipsos-Reid Express, had 1300 respondents, including 600 from British Columbia, Alberta, Saskatchewan and Manitoba (Sharp, 2008).

Awareness of Carbon Capture and Storage has increased over the last few years. A study conducted in 2005 found that about 10% of Canadians and 15% of residents in Saskatchewan and Alberta had an awareness of CCS. A 2007 study found this number to have increased to 31% of Canadians and 40% of Albertans. When Canadians were asked in the 2007 Ipsos Reid poll on their level of support for CCS, 62% of respondents said they supported it (19% strong, 43% somewhat). The Prairie Provinces had the highest level of support, approaching 70%.

Both surveys sought to understand the reasons behind public support of CCS and in both cases, the results shown that Canadians viewed CCS as a bridging technology by which short-term reductions in GHG emissions could be achieved while sustainable, long-term solutions were being developed. In the 2007 survey, more than two-thirds of the respondents agreed that CCS was a good option for enabling Canadian industries to contribute to solving climate change and just under two-thirds agreed that the technology provides Canadians with an opportunity to become a clean energy “superpower”.

It should also be noted that nearly 70% of respondents also agreed with the statement that CCS sounds like sweeping a problem under the rug, rather than solving a problem. The most common concern amongst those who opposed CCS was the possibility of leakage or other problems arising from underground storage of CO_2 (Sharp, 2008).

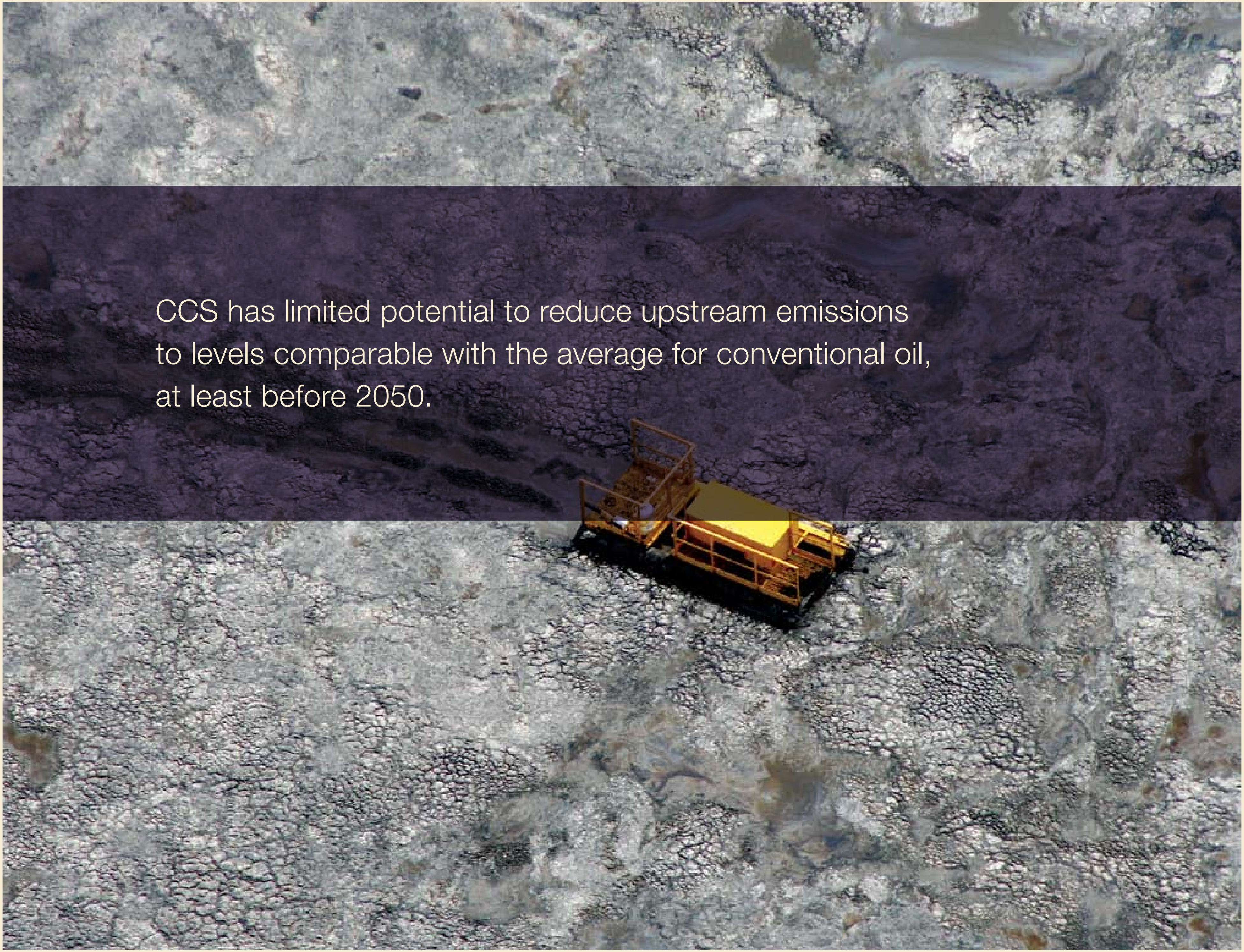
A survey administered by The Pembina Institute in 2008 sought to understand sentiment from various sectors. Respondents were from industry (50), NGOs (20), government (9), and academia (8). While the survey is less representative, of particular interest are the issues raised by the various bodies. Cost effectiveness was amongst the most important issues by all four sectors, and government policy certainty and stability was also amongst the most important issues for Industry, Government, and Academia. The security of storage and liability were also flagged as the most important issues for NGOs (Sharp, 2008).

4.5.1 Consolidating Positions

Table 4.5-1 summarizes the relative perspectives of various stakeholders, as well as the key concerns raised. The private sector is pursuing commercialisation of CCS to a limited degree, but wants to see significant public sector investment in order to defer costs. Encana, for example, in its 2007 Corporate Responsibility Report in the section on Climate Change indicates that is strategy for climate change involves three facets: managing existing costs, responding to price signals, and planning for future carbon constraints. In the case of the provincial and federal governments, both say CCS will make a significant contribution to the overall reduction or provincial and federal greenhouse gas emissions, while the joint ecoEnergy task force has recently talked about the limited application of CCS in oil sands. Amongst stakeholders, positions and expectations are clearly divided, as are expectations with respect to the potential of CCS in oil sands operations.

Table 4.5-1 Stakeholder Positions Regarding Carbon Capture and Storage in the Oil Sands

STAKEHOLDER	SUMMARY OF POSITION
Unsupportive ENGO’s	Carbon Capture and Storage in the oil sands is unproven, carries too much risk and is too expensive; efforts and resources would be better spent pursuing energy efficiency, renewable energy, and other ways of reducing greenhouse gas emissions.
Cautiously Supportive ENGO’s	Carbon Capture and Storage in the oil sands may be technically feasible and should be pursued immediately to reduce greenhouse gas emissions, but not at the expense of more cost-effective and proven alternatives.
Government	Carbon Capture and Storage in the oil sands will play a significant role in reducing greenhouse gas emissions in Alberta and in Canada. Perspectives on the potential for GHG reductions through CCS differ.
Private Sector	Carbon Capture and Storage will be a key method of addressing climate change issues in the oil sands. The cost of implementing CCS systems and developing a network is expensive, and while industry will be involved, significant support should be provided by the public sector.
Public	Carbon Capture and Storage may be a good option for Canadian industries to contribute to solving climate change with the benefit of being a bridging technology to achieve short-term reductions while long-term alternatives are developed. But security of storage is a concern and most also agree with the statement that CCS sounds like sweeping a problem under the rug.



CCS has limited potential to reduce upstream emissions to levels comparable with the average for conventional oil, at least before 2050.

SYNTHESIS AND ANALYSIS

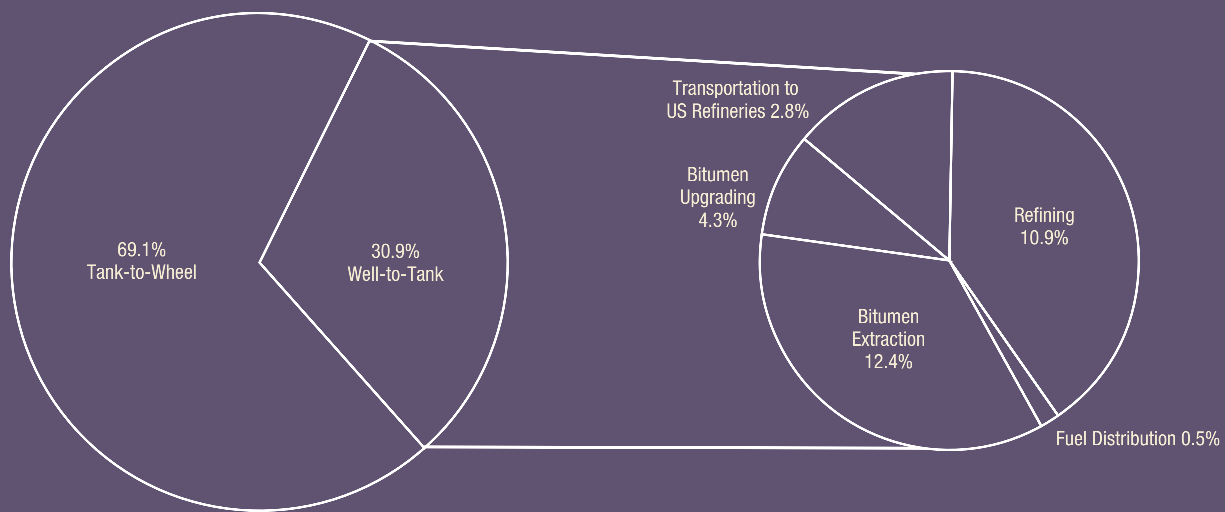
5.1 Technology Readiness of CCS

Where GHG concentrations are amenable, some technological facets of the oil sands do lend themselves to separating and capturing a gaseous stream of CO_2 with relative technological ease. They occur only in particular places in the Well-to-Wheel spectrum of activities, and have a relatively small contribution to the total release of carbon contained in the final product (Figure 5.1-1). Successful capture and storage of some upstream CO_2 emissions will improve the carbon footprint of oil sands oil, at the expense of efficiency of the overall operations, but will not eliminate the vast majority of greenhouse gas emissions, which happen at the point of use that is commonly transport related.

5.1.1 Well to Refinery: Production of SCO

Of the emissions associated with production of SCO, the greatest opportunity for CCS arises in the hydrogen production process, which contributes to approximately one-third of the greenhouse gas emissions associated with SCO production. The production of hydrogen produces a high purity CO_2 stream as part of the water gas shift reaction, and this CO_2 requires separation to produce hydrogen for hydrocracking. Most fugitive emissions and the emissions associated with diesel combustion are not practical to capture at present.

Figure 5.1-1 Life Cycle GHG Emissions (Woynillowicz, 2008)



It is significant that most proposals from industry concerning CCS in oil sands operations have focused on CO_2 sequestration from hydrogen plants. Little discussion of capturing CO_2 in flue gases arising from fossil fuel combustion for steam production from current energy sources has occurred. Recent studies have commented upon the use of CCS to mitigate further growth in emissions as a result of a switch to higher-carbon content fuels such as petcoke (Ceri, 2009), however these have not yet been taken up by industry players.

5.1.2 Refinery-to-Tank: Production of Gasoline Oils

As with upgrading operations, refining operations have significant GHG emissions associated with hydrogen production and fossil fuel combustion for steam production. Here, again, CCS for the CO_2 by- product produced from hydrogen plants in an area of obvious focus.

5.1.3 Tank-to-Wheel

Technology for CCS of emissions from vehicles and small generators is in the earliest stages of development at best. While there are small, individual projects focusing on mobile CCS (Damm 2006), the technological readiness to effectively capture carbon dioxide from the dominant use – mobile transport providers – is small.

5.1.4 Well-to-Wheel

The technical ability of CCS to reduce greenhouse gas emissions from a life-cycle or a Well-to-Wheel perspective is moderate, even under best case industry scenarios. Combustion of transportation fuels by end users accounts for approximately 70% of total greenhouse gas emissions. Of the remaining 30%, the most optimistic estimates have suggested that overall reductions from upstream operations could be in the 30% to 50% range by 2050, accounting for at best between 9% and 15% of total life-cycle emissions.

A recent study by the RAND think-tank summarises the potential technical impact of CCS technologies based on oil sands emissions intensity estimates generated by the Pembina institute. The RAND study looked at the potential economics of SCO production with CCS in 2025 and assumed the capture of all point sources – a CCS rate of 85% of upstream emissions, not something even the most optimistic of oil sands producers are suggesting would be widely applied. Yet, even under this theoretically possible, but highly unlikely CCS capture scenario, oil sands GHG intensities merely fall to ranges comparable with conventional sources.

Furthermore, it is unlikely that the sector as a whole will be able to meet existing international low carbon fuel standards or the UN-PRI target of matching greenhouse gas emissions per barrel of conventional oil by 2020. This is compounded by current adoption trajectories and targets/timelines being called for in a number of industry-supported studies. For example, the current proposal, outlined in the joint industry-government ACCSDC report only calls for pilot projects in the 2010-2015 period, followed by the introduction of a CCS requirement for some new operations in the 2015 to 2020 period, and full commercial deployment post 2025.

5.2 Economic Feasibility of CCS

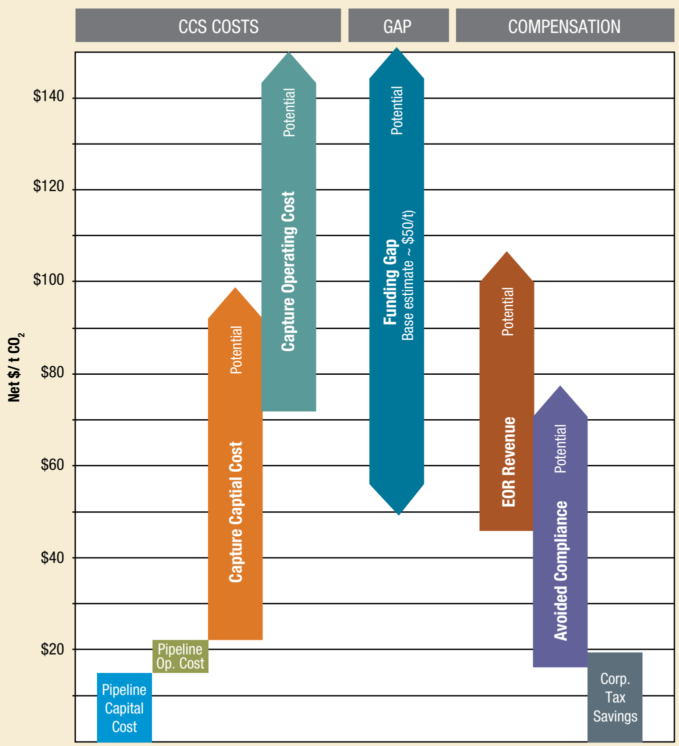
The price of oil has a significant impact on the economic feasibility of CCS technologies. In the last year, the price of oil has dropped as low as $35 per barrel and the impact on oil sands projects has been significant. Oil sands producers are also expected to face greater challenges in the medium to long term as stocks of natural gas – heavily used for power and hydrogen production – decline province-wide. The Alberta Government's currently carbon off-set system supports a floor price of CO_2 of $15/tonne, well below the best cost estimates for carbon capture of between $60 and $250/tonne.

When considering the learning curve and future CO_2 prices, the cost of mature commercial systems may be in the range of CO_2 price forecasts. In the near term, however, costs are a significant barrier, and the current off-set market in Alberta for CO_2 is not adequate to provide incentives for CCS. Many of Alberta's largest companies including Suncor and Syncrude have chosen to hold off on further plans for carbon capture and storage projects and declined to apply for funding offered by the Alberta government for CCS demonstration. High costs and the belief that CCS money can be better used for coal-fired plants and larger, more concentrated sources of emissions were amongst the reasons cited for the recent decisions. The Hypothetical economic profile of CCS opportunities in the province shown in the figure below summarises the cost related conclusions of the recently released Alberta Carbon Capture and Storage Council report and the level of public sector support they estimate is necessary to achieve commercial viability. The magnitude of the gap and potential additional revenues from EOR royalties (from $11 to $81 billion depending on oil prices) are key pieces to the Council report's business case for further government support for CCS.

However, as noted in *Section 3.2*, using captured carbon for EOR rather than sequestering could actually result in an increase in net atmospheric carbon emissions because of improved recovery of fossil fuels. This is potentially significant, as the ACCSDC has estimated that EOR could effectively double Alberta's recoverable conventional oil reserves. The emissions resulting from the production and normal use of this oil would be greater than the amount of carbon sequestered underground from CCS operations.

Hypothetical Economic Profile

(Facility with ~ $100/t capture costs)



Source: Development Council Evaluation

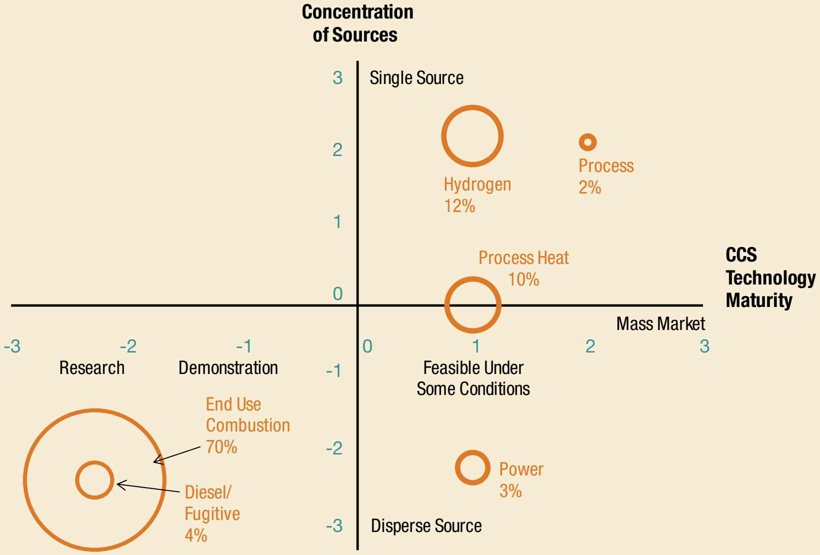
5.3 Opportunities for CCS in Alberta's Oil Sands

When evaluating the opportunities for CCS in Alberta's Oil Sands, both the technology readiness and the economic feasibility come into play. Figure 5.3-1 profiles CCS activities according to the maturity of CCS technology as assessed by the IPCC together with concentration and level of dispersion of the CO_2 emissions source. Combustion of transportation fuels, combustion of diesel, and fugitive emissions releases are disperse and systems for CCS from these sources are non-existent or in the very early stages of research. Emissions from power production or from fired boilers used to produce heat are typically atmospheric with relatively low concentrations of CO_2. Capture of these post-combustion emissions is technically feasible, but limited by economic feasibility. Process emissions and some pre-combustion hydrogen production facilities have rich CO_2 sources with relatively high partial pressures/ CO_2 concentrations, and these streams are most amenable for CCS. Estimates for the amount of CO_2 reductions achievable from oil sands operations, which have suggested reduction opportunities in oil sands activities of 10-30% at only the most favourable locales in the near term (3-9% of Well-to-Wheel emissions) essentially reflect the fact that current opportunities for reductions lie in the top right quadrant of Figure 5.3-1.

5.4 Policy Readiness for CCS

Within Alberta, some procedural regulations exist for the use and management of injection wells, including well construction, operation, and abandonment. As early as 1994, Directive 51 was established and defined various classes of injection wells. Class III wells are used for the injection of hydrocarbons or other inert gases for the purpose of storage in or enhanced hydrocarbon recovery from a reservoir. Included in this category is CO_2 used for storage or enhanced recovery. There are, however, still policy gaps with respect to long-term CCS.

Figure 5.3-1 Opportunities for CCS in the Oil Sands – End use combustion accounts for the vast majority of CO_2 emissions. A very small portion of CO_2 emissions from oil sands is available for capture.



5.4.1 Monitoring and Verification

Standards for measurement, monitoring and verification of CCS projects are crucial as these activities provide critical information on containment, leakage, and seismic activity in surrounding areas. Phase II of the Weyburn project, which is expected to inform policy decisions regarding monitoring requirements, has yet to be completed. Policy requirements for site specific monitoring programs to track migration of CO_2 and evaluate trapping mechanisms must be established, together with levels for operational, verification, and environmental monitoring. The current suite of projects across the world from the R&D phase to the commercial phase involves a variety of geological settings including deep saline aquifers and different geological media. Understanding site-specific factors and variations across data being generated from the various projects will be important to developing monitoring and verification standards. Carbon accounting schemes and greenhouse gas emissions inventories would also need to be adjusted not only for consideration of CCS, but also for any leakage that occurs from CCS projects (IPCC, 2005).

5.4.2 Liability

Liability issues impact the costs associated with CCS and will also play a role in furthering public acceptance and attracting private investment. Operational liability covers the short-term for a CCS project and can be considered as the timeframe of the project as well as a contractually assigned project timeline thereafter. Over the long-term, however, CCS may have environmental, in situ, and transborder liabilities that extend anywhere between a hundred years and thousands of years. Regulatory and policy models for short-term liability exist in the oil and gas sector. Regulations for long-term liability, however, have little precedent. The concern of long-term liability involves leakage or migration that can contribute to atmospheric CO_2 emissions. At the same time, regulatory mechanisms to correct accounting inventories may also need to be devised to reverse assigned credits. Not only does there need to be greater clarity on time frames for assigned liabilities, but delineation of ownership and responsibilities amongst government bodies and private corporations must also occur (Robertson, 2006).

5.5 Impact of CCS on Canada's Climate Mitigation Strategy

Most predictions regarding wide scale commercial application of CCS technologies place their deployment between 10 years and 15 years into the future, at best. Significantly, the IPCC WGIII report suggests that "notwithstanding significant penetration of CCS systems by 2050, the majority of CCS deployment will occur in the second half of this century" (IPCC, 2005). The importance of viewing the application of CCS in the oil sands in context of the life cycle of production is highlighted by considering that end user consumption accounts for about 70% of the Well-to-Wheel CO_2 emissions. Of the 30% CO_2 emissions from mining, extraction, and refining, the emissions from hydrogen production facilities are the most easily targeted. Emissions from fugitive releases and diesel combustion impractical to recover, and low pressure flue gases with low amounts of CO_2 are challenging.

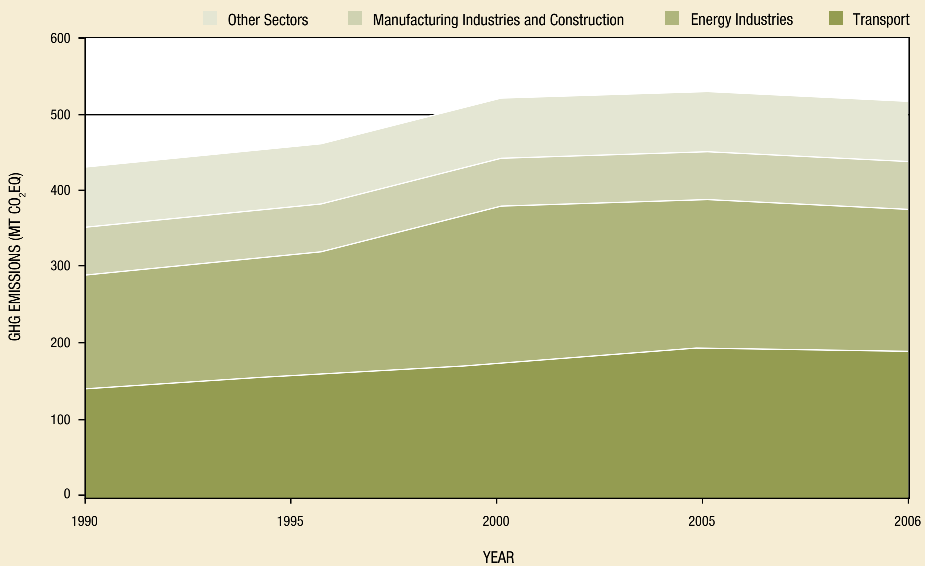
Given that technology for Tank-to-Wheel capture of CO_2 emissions is primitive at best, CCS in the oilsands cannot be considered a mitigation measure with sufficient scope to deal with the magnitude of the issue. Demonstrating this, Figure 5.5-1 shows the contribution of various sectors to Canada's GHG emissions inventory to 2006. Note that the emissions associated with transportation are equal to all energy industry activities, including power generation. Projecting this sectoral comparison into the future, commentators have predicted that "If oil sands production increases as expected and the emissions entailed in producing each barrel are not reduced, that contribution will roughly triple by 2030, making oil sands a huge relative contributor to Canadian emissions but still a relatively marginal one in the U.S. and global contexts. If, however, policy efforts manage to slash other emissions, as they must if ambitious goals for reducing the risk of catastrophic climate change are to be met, the relative prominence of the oil sands would greatly increase. Imagine, for example, that oil sands emissions rose as expected over the next two decades and then stabilized in 2030, while total U.S. and Canadian emissions dropped by 80 percent by 2050 (an oft-proposed target). Oil sands emissions would then become equivalent to about 10 percent of U.S. emissions by 2050, representing almost all emissions from Canada at that point. Oil sands' emissions will thus be critical to deal with in the long term though not as important in the immediate future." (Levi 2009)

A recent academic paper (Ordorica-Garcia 2009) modelled maximum emissions reductions from specific plants and found that deep emissions reductions (>30%) from the industry were only possible when CCS was applied to natural gas fuelled plants, rather than gasification of Petcoke and ashphaltenes, a suggested means of reducing industry dependence on natural gas supplies and reducing costs. Use of these waste fuels, with or without CCS, were shown by report for Environment Canada (Bowers et. al. 2008) to result in an increase of many other air pollutants including NOx, SOx and some emissions of heavy metals. Production of 1.3 million bpd of SCO in 2008 has been projected to increase to 7.0 million bpd in capacity if all approved, in application for permits, announced or disclosed projects are executed (CERI 2009).

Figures 5.5-2 and 5.5-3 shows the relationship between expected lifecycle and upstream emissions (from Well-to-Wheel and Well-to-Tank respectively) from oil sands sources under constrained growth forecasts from the current production level of 1.3 million bbl/d to 5.5 million-bbl/d by 2050.

Figure 5.5-3 (WTT emissions) illustrates how, even with the aggressive deployment of CCS the sector's upward emissions trend will continue. At the upper rate of implementation, by 2020, a maximum of 30% of upstream CO_2 emissions from oil sands activities could be captured (around 7% of WTW emissions), resulting in a net increase in emissions from the industry more than double 2007 levels. The emissions from the oil sands in 2050 predicted by the maximum technically achievable amounts captured shown in the charts (approximately 131MT by 2050 – a high estimate) are greater than Canada's entire carbon budget in 2050, i.e. where emissions are 80% below1990 levels by 2050 (i.e. (118MT). These charts do not consider additional energy used for CCS, boreal forest destruction, tailings ponds and other emissions, or choice of energy supply (i.e. natural gas or Petcoke and ashphaltene gasification) which commentators (Ordorica-Garcia 2009) have suggested could limit the reduction levels due to higher carbon content of initial fuels. That the largest portion of WTW emissions shown in Figure 5.5-2 will occur at the point of use, and therefore not necessarily in Canada, reinforces that this is a global climate problem in which it is imperative that international actors are included in an evaluation of options.

Figure 5.5-1 Contribution of Sectors to National GHG Emissions



A recent MIT study using their in-house economic modelling program elucidated how in the face of a high cost of emissions in Canada, there exists a significant potential for leakage from the bitumen processing activity to less restrained emissions environments, which is particularly evident in the case where CCS is not available as a mitigation option for Canadian producers.

On a global scale, bitumen processing leakage from Canada due to restrictions on the availability of CCS or other low cost mitigation measures may lead to a net increase in emissions. Models results suggest that an average of 87% of upgrading capacity could leak from Canada during the 2010 to 2050 timeline, even at a $25/tonne price levels. “Commercial CCS technology could allow bitumen production growth under strict CO_2 policies. Commercial CCS could also keep a portion (20-50%) of bitumen upgrading in Canada that would, under similar conditions but without CCS, move out of the country.” (Anderson, 2008).

As international efforts to address CO_2 emissions intensify, cap-and-trade systems and legislation such as the Californian and EU Low Carbon Fuel Standards are likely to become more commonplace. A number of US states now have proposals for such standards. This could have major consequences for Alberta’s oil sands and the companies who operate there. The Californian and EU standards come into effect in 2010, prohibiting transport fuels with lifecycle CO_2 emissions greater than the 2010 average and requiring reductions in lifecycle CO_2 emissions of between 6% and 10% by 2020.

In the short term, the oil industry is generally expected to meet these upcoming standards by blending above average conventional oil with biofuels. However, barriers to the sustainable development of large-scale biofuel production exist, such as the lifecycle carbon emissions of some feedstock, land use change and food prices. Current export market access for the oil sands largely depends upon the outcome of the new US administration’s energy policy, with alternative markets posing different but equally significant problems.

Figure 5.5-2 WTW Emissions of Oilsands Products With and Without CCS

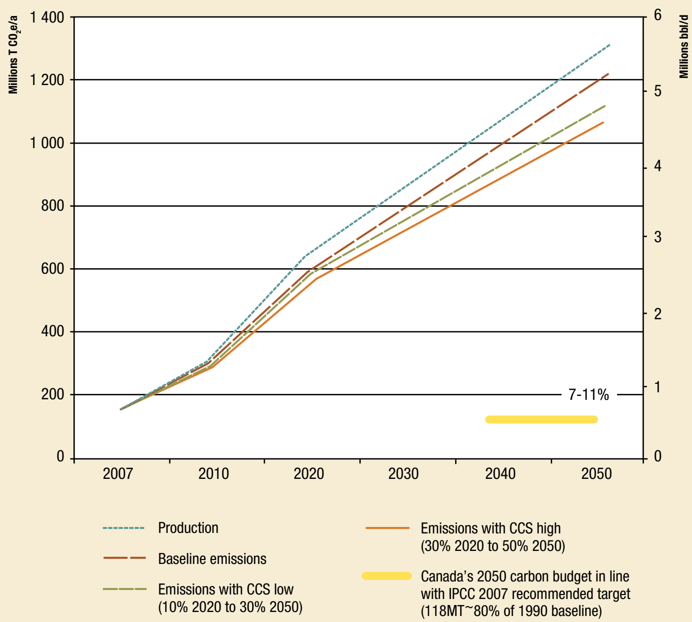
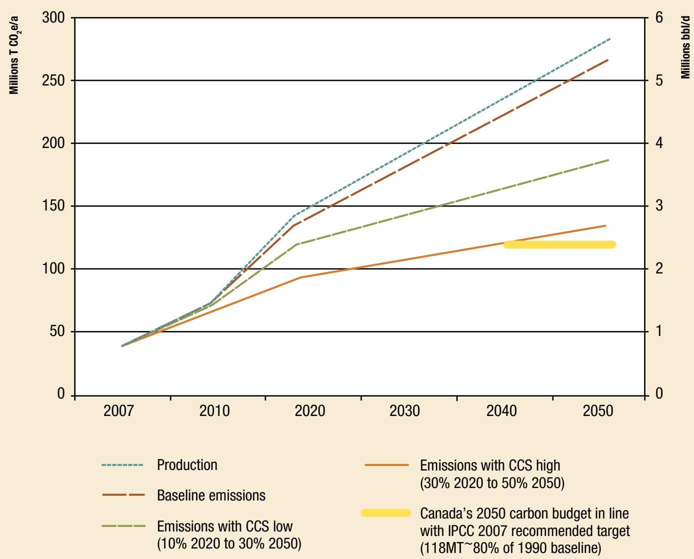


Figure 5.5-3 WTT Emissions from Oilsands With and Without CCS



The application of CCS into oil sands activities will not enable Canada to meet its international climate change commitments.

CONCLUSIONS

- Oil sands production reached 1.3 million bpd in 2008. Current projections place production between 2.5 and 4.5 million bpd by 2020, with capacity possibly as high as 6.2 million bpd. As at February 2009, licenses had been granted for the production of 7 million bpd.
- Even on the assumption of a constrained growth forecast for oil sands developments and the aggressive deployment of CCS, rather than what is likely, projected upstream emissions from the oil sands alone are set to exceed the whole of Canada's 2050 carbon budget, were it to meet the IPCC 2007 recommended GHG reduction target of 80% on 1990 GHG levels.
- Optimistic industry estimates for CCS have suggested that overall reductions from upstream operations could be in the 10% to 30% range at the best process locations by 2020 and the 30% to 50% range industry wide by 2050. This would account for at best between 3% and 9%, and between 9% and 15%, of total life-cycle emissions by 2020 and 2050 respectively.
- The cost of applying CCS to oil sands developments is high and does not compare favourably with capturing emissions from highly concentrated sources such as coal fired power stations. SAGD for instance is estimated to be capturable in the range of $200 to $290 per tonne of CO_2, compared to $60 to $150 per tonne for coal fired power stations in Alberta.
- CCS is unlikely to make a significant contribution to reducing the GHG intensity of oil sands products sufficiently to meet emerging international low carbon fuel standards, at least until 2050.

GLOSSARY AND ABBREVIATIONS

Bitumen
A tar-like mixture of petroleum hydrocarbons with a density greater than 960 kilograms per cubic metre.

Diluent
Light petroleum liquids used to reduce the viscosity of heavy crude oil, or fractions, particularly bitumen, so that it can flow more easily through pipelines.

EOR
Enhanced Oil Recovery

Froth treatment
A process for recovering bitumen from the water, bitumen and solids froth produced in a hot water extraction process.

FCC
Fluid Catalytic Cracking

Hydrocracking
A process for reducing heavy hydrocarbons into lighter fractions, using hydrogen and a catalyst.

Hydrotreating
A process for treating petroleum fractions from atmospheric or vacuum distillation units and other petroleum by placing these feedstocks in contact with substantial quantities of hydrogen under high pressure and at a high temperature in the presence of a catalyst. Hydrotreating includes desulphurization, removal of nitrogen and metals, and conversion of polyaromatics and olefins to paraffins. It is usually a final stage in the upgrading process.

Middlings
A suspended mixture of clay, sand, water, and some bitumen.

SAGD
Steam Assisted Gravity Drainage

SOR
Steam-Oil Ratio

Synthetic crude oil (SCO)
A high quality, light, usually sweet, crude oil derived by upgrading heavy crude oil, particularly bitumen, through the addition of hydrogen or removal of carbon. It comprises mainly pentane and heavier hydrocarbons.

Syngas
A gas comprised of hydrogen (H2) and carbon monoxide (CO), also used for the synthesis of new chemicals (syngas is also short for synthesis gas).

Tailings
A combination of water, sand, silt and fine clay particles that are a byproduct of removing the bitumen from the oil sand.

Vacuum distillation
The vacuum distillation unit (VDU) separates by fractionation most of the petroleum fractions that vaporizes without thermal cracking from atmospheric distillation residuum under nearly full vacuum (i.e., near zero absolute pressure) when heated up to between 700°F and 800°F.

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