WWF

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

The **co-operative** bank
insurance
investments

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.

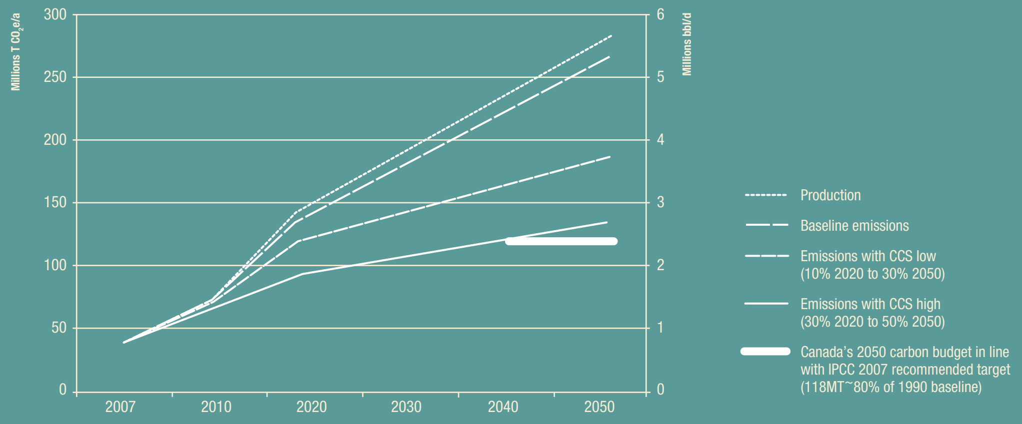
The maximum reductions achievable using CCS would therefore be insufficient to meet emerging low carbon fuel standards, such as those in the European Union and California, even by 2050.

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



CONTENTS

1. Alberta Oil Sands

2. GHG Emissions from Oil Sands

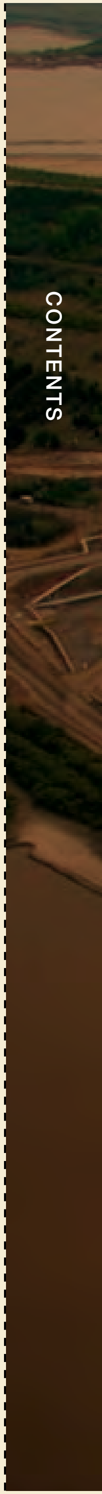
3. Carbon Capture and Storage

4. Perspectives on CCS

5. Synthesis and Analysis

6. Conclusions

7. References



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

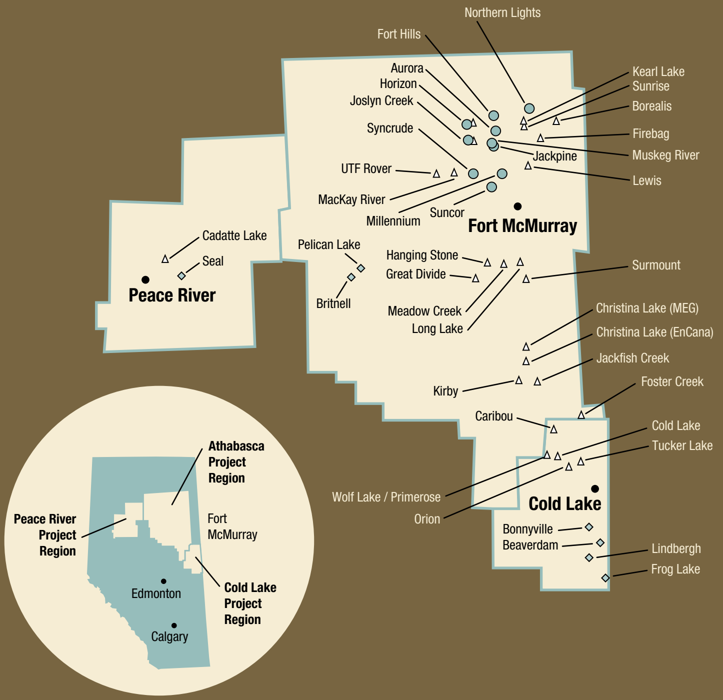
1.1 Introduction to the Oil Sands

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).

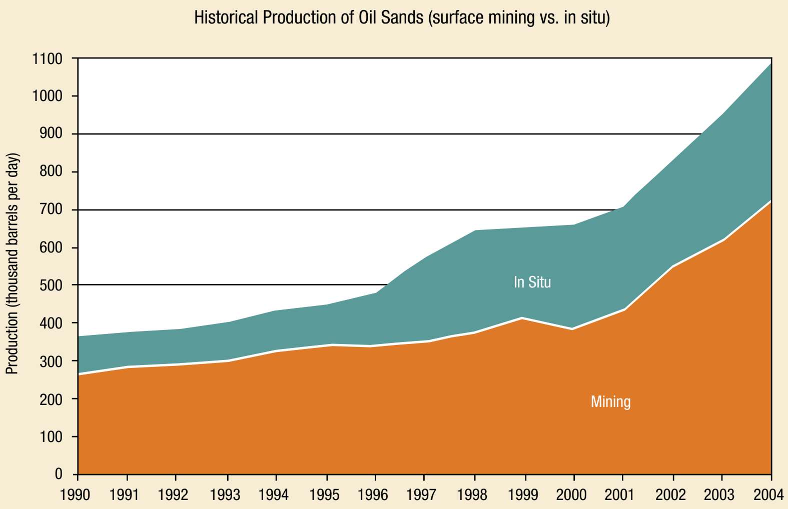
Figure 1.1.1-1 Oil Sands Regions in Alberta (Alberta Government, 2006)



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).

Figure 1.1.2-1 Bitumen Production by Type of Mining

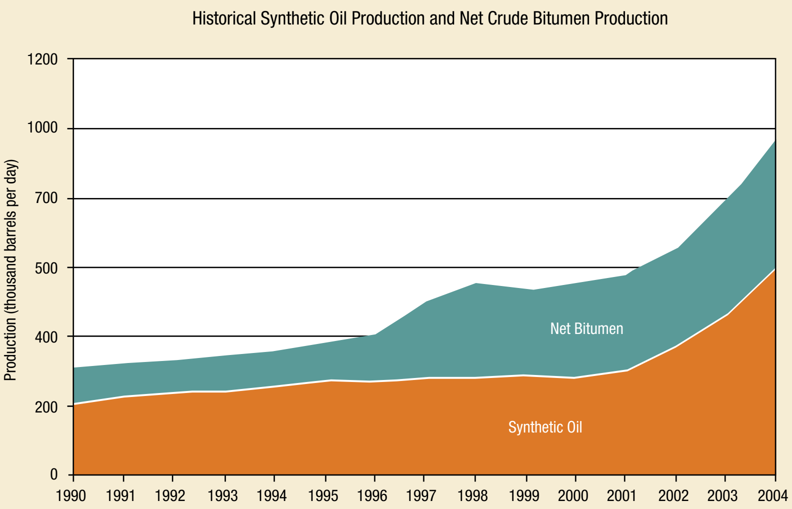


Source: Derived from Alberta Energy and Utilities Board ST 39 & ST 53

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 1.1.2-2 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.

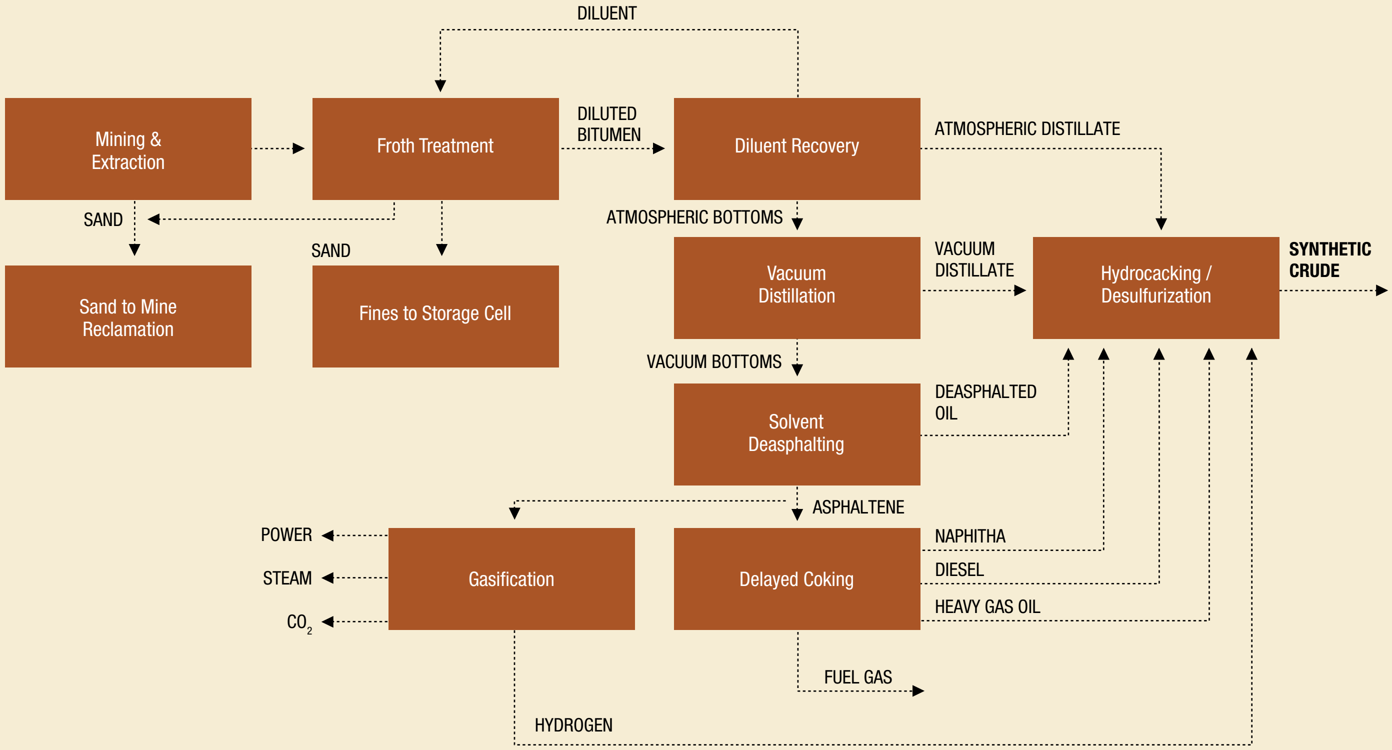
1.2.3 Upgrading

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)



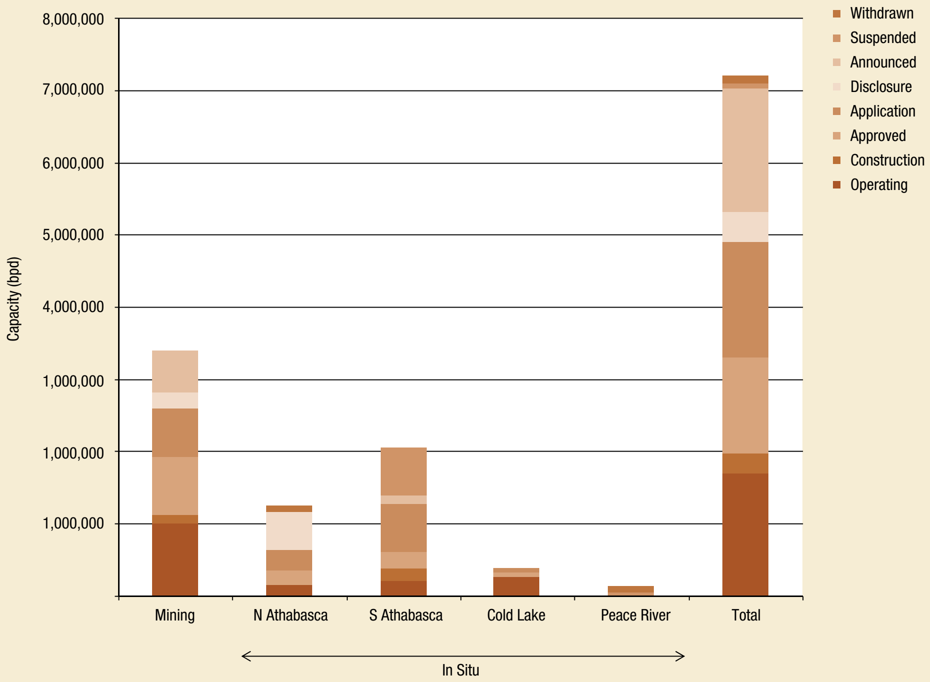
1.3 Production Trends

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.

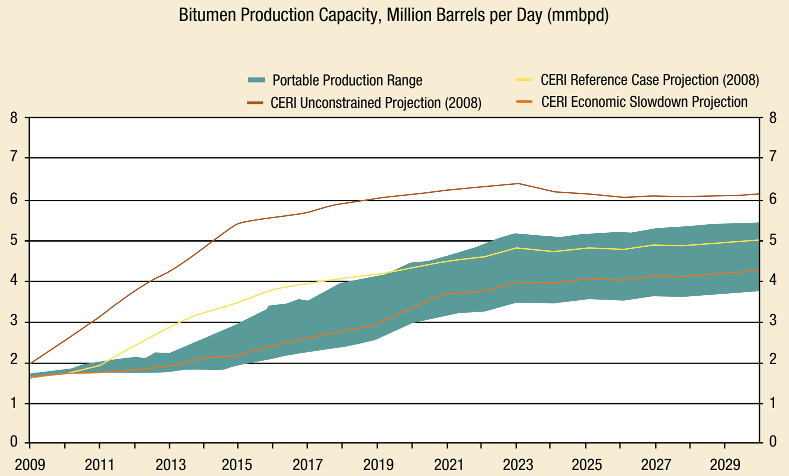
Figure 1.3.1-1 Existing and Proposed Bitumen Producers, February 2009 (Dunbar, February 2009)



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.

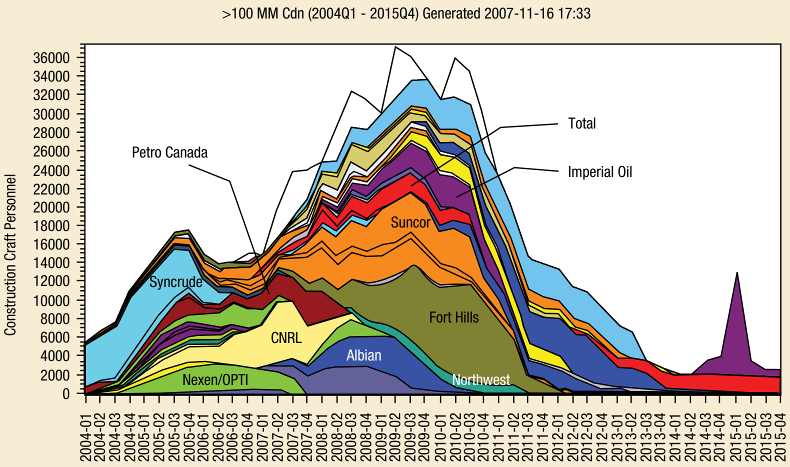
Figure 1.3.1-2 Projected total bitumen production growth given different economic scenarios (McColl, February 2009)



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 1.3.2-1 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 2.1-2 Canada’s Greenhouse Gas Emissions 1990-2007 (Environment Canada)

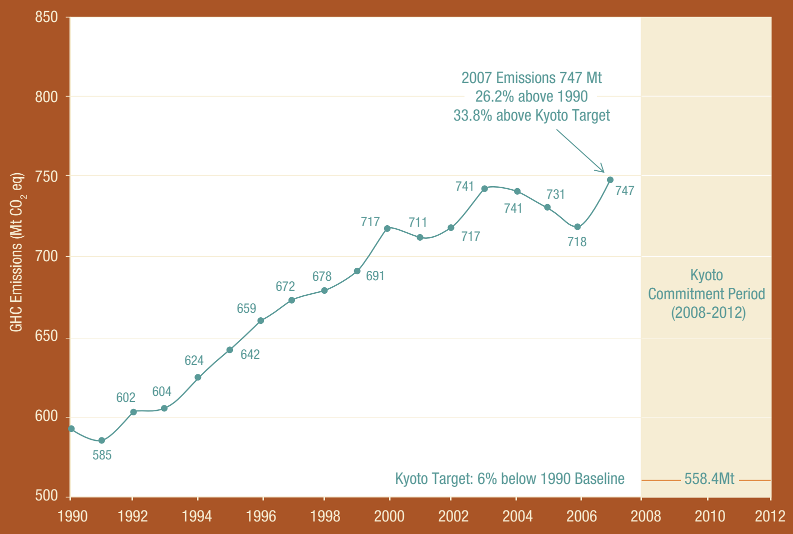


Figure 2.1-2 shows the various activities from which GHG emissions arise from a life cycle basis. A life-cycle basis considers all direct and indirect emissions from extraction at the well to combustion of the final transportation fuel, and is often referred to as a 'Well-to-Wheels' assessment. From 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

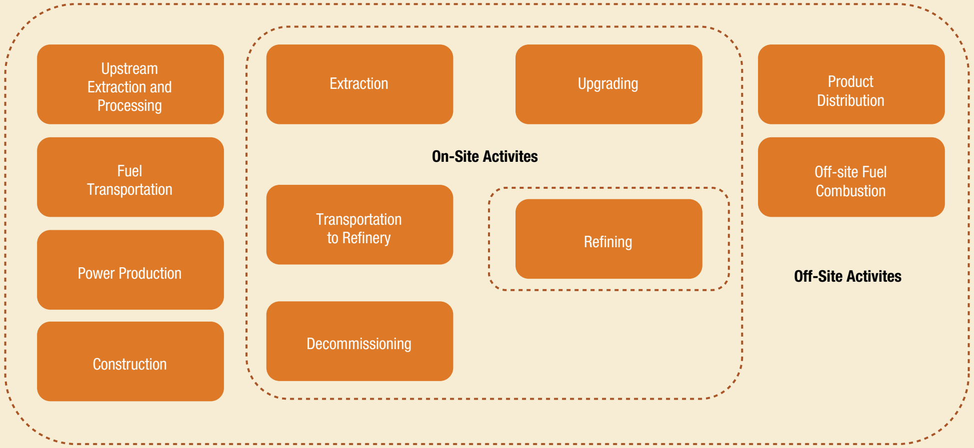
Very few studies have characterised GHG emissions associated with the construction of new facilities. These emissions are typically neglected in LCA studies for energy facilities as they are often an order of magnitude lower than emissions associated with fuel combustion. Bergerson and Keith (2008) suggest 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

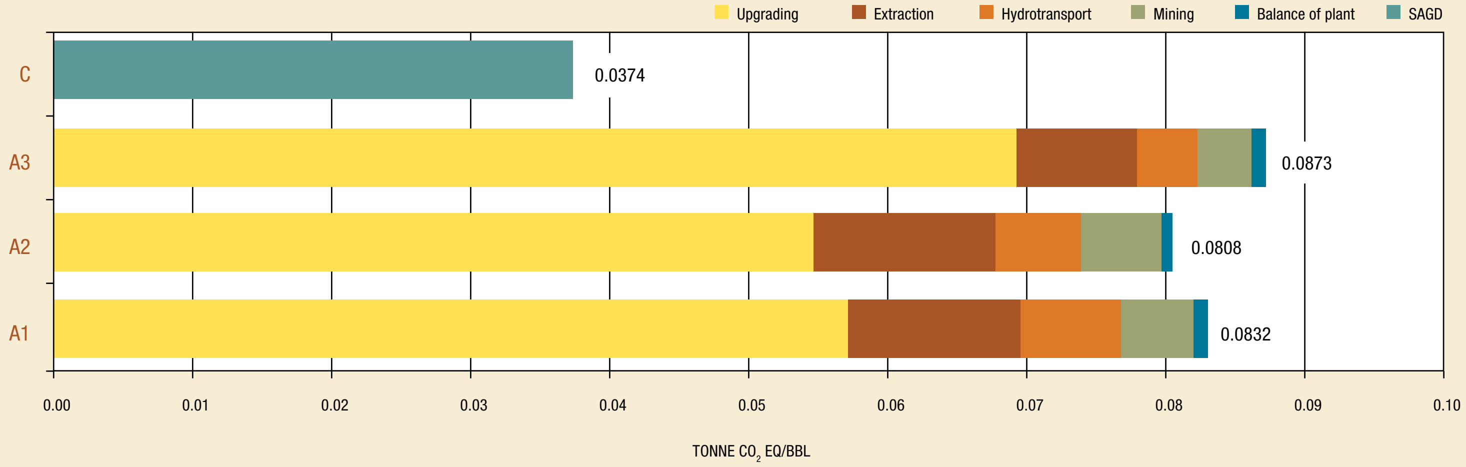
The main sources of greenhouse gas emissions during in situ extraction arise from fossil fuel combustion for the production of steam. Steam is typically produced using natural gas in steam boilers, and the steam-to-oil ratio, an indicator of efficiency of the operation, is typically between 2 and 3.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



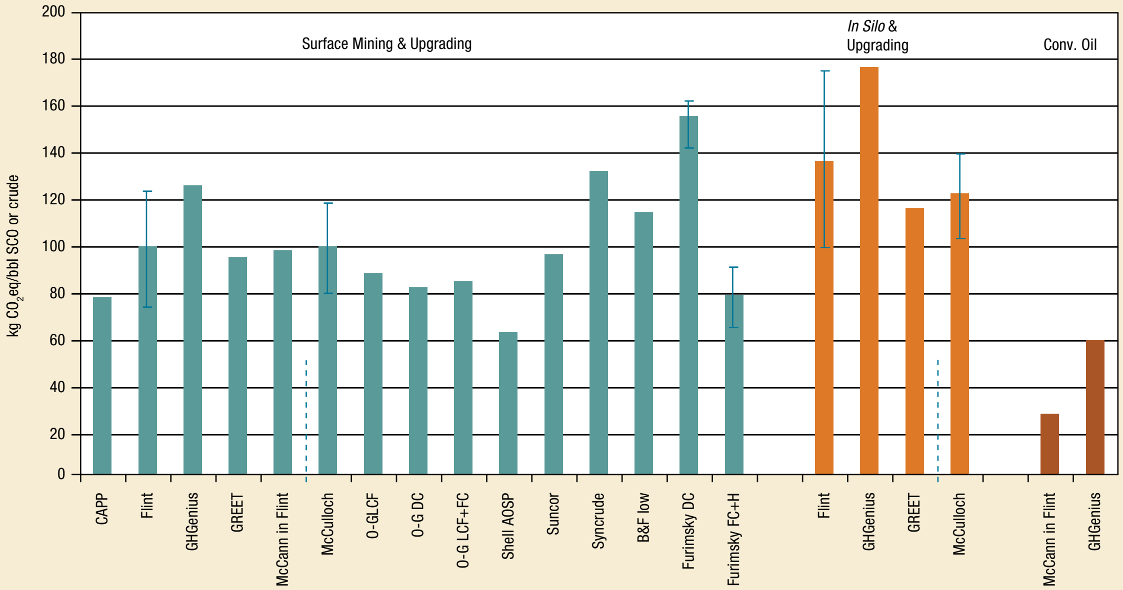
low sulfur products), FC (Fluid Coking where heat is employed rather than hydrogen for the cracking process), and Hydrotreating (A1), surface mining with bitumen upgrading by delayed coking and hydrotreating (A2), and surface mining with bitumen upgrading by LC Fining and hydrotreating (A3). The study 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)



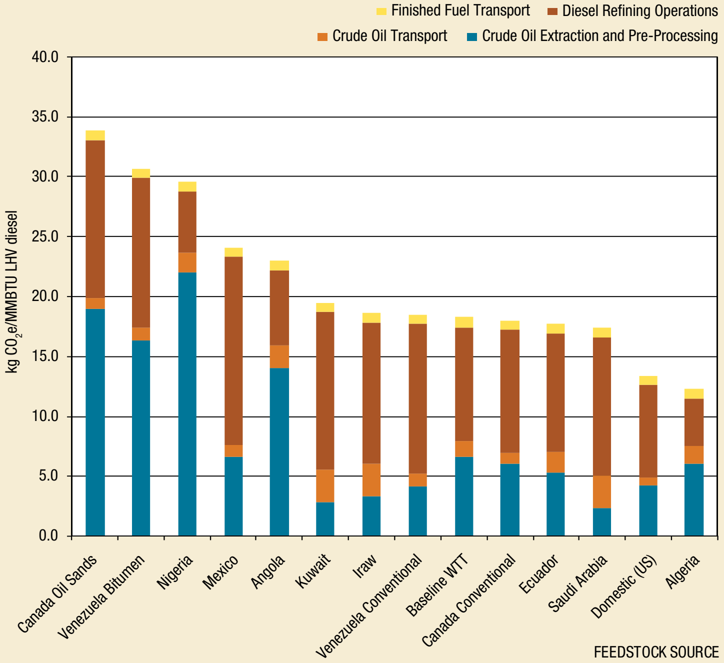
2.2.4 Refinery-to-Tank: Production of Gasoline Oils from SCO

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.

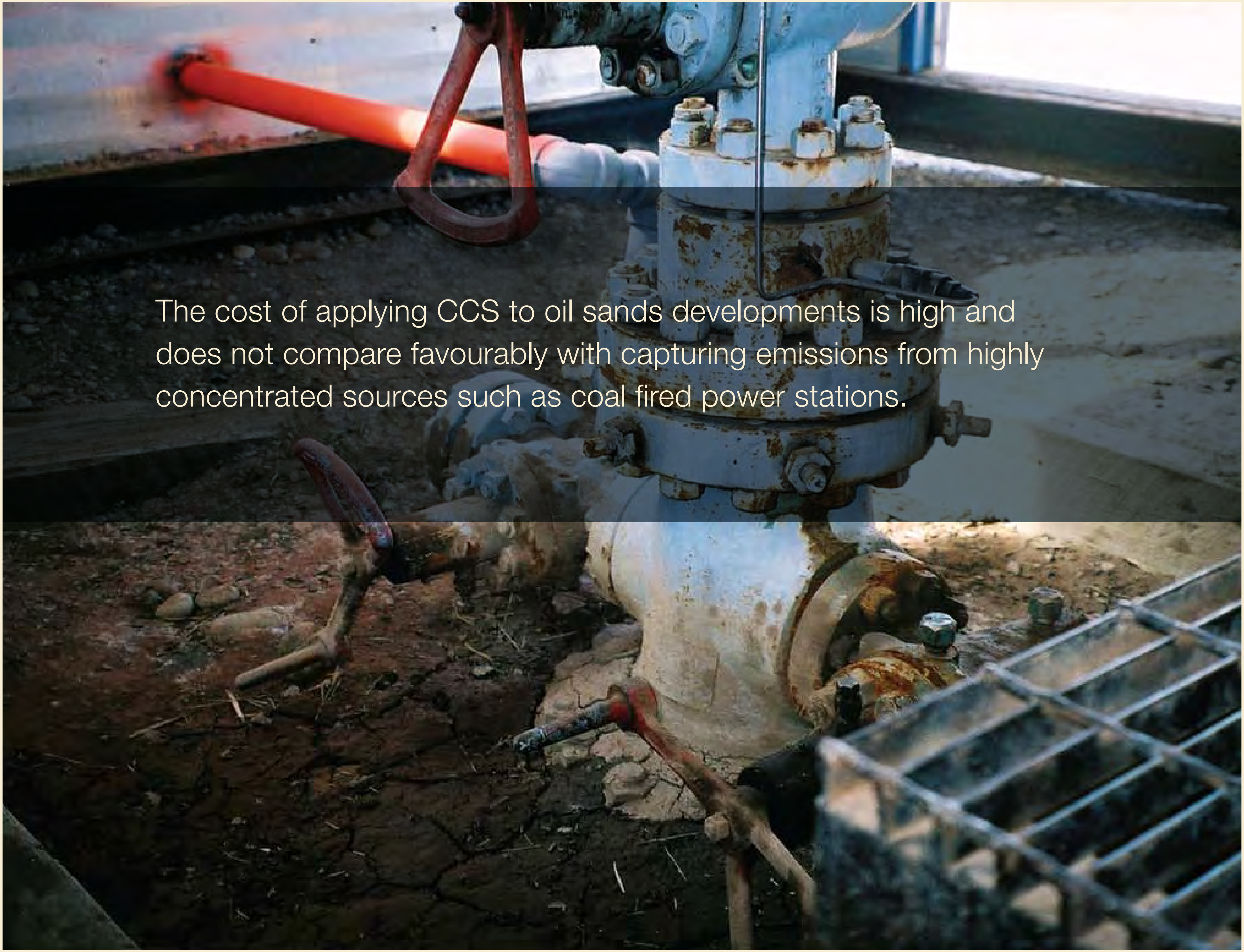
Production of fuels from the Canadian Oil Sands is significantly more carbon intensive than production of fuels from any other feedstock. Environment Canada's National Inventory Report on Greenhouse Gas Sources and Sinks in Canada 1990-2007, found that "oil sands mining, extraction and upgrading activities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

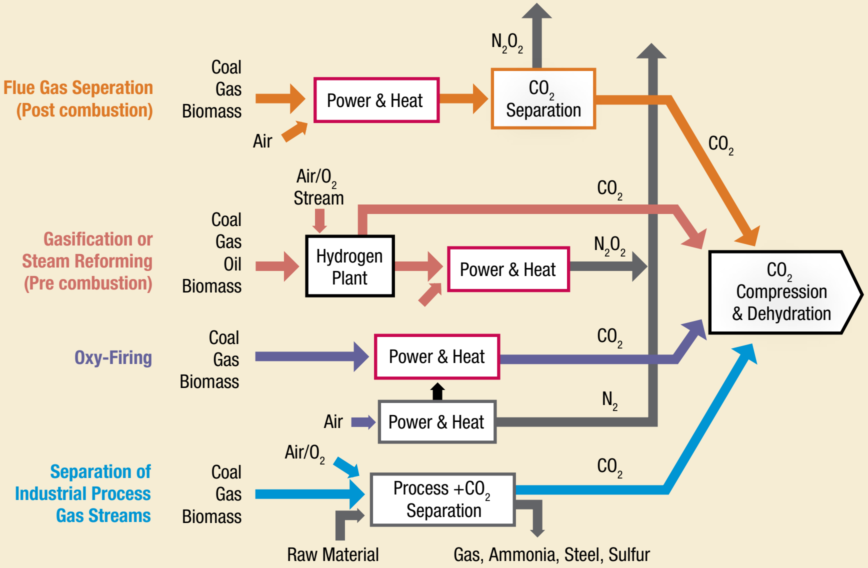
Oxy-fuel

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% O_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 3.1.2-1 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.

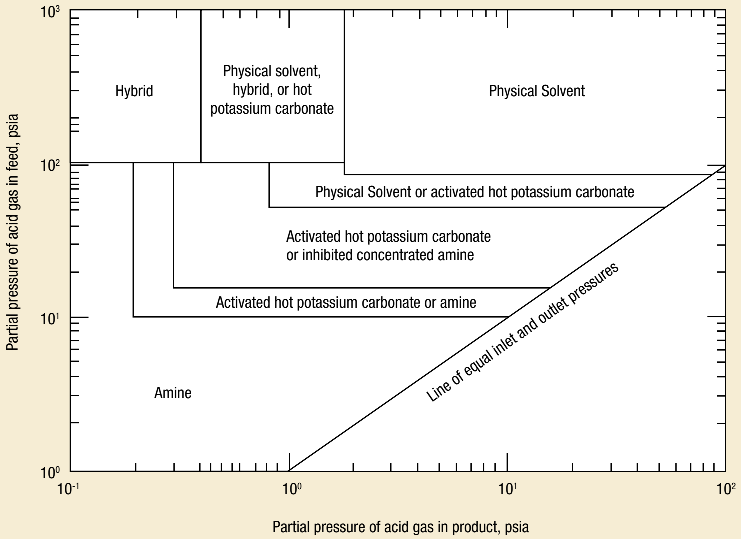
Membranes

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 3.1.2-1 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.

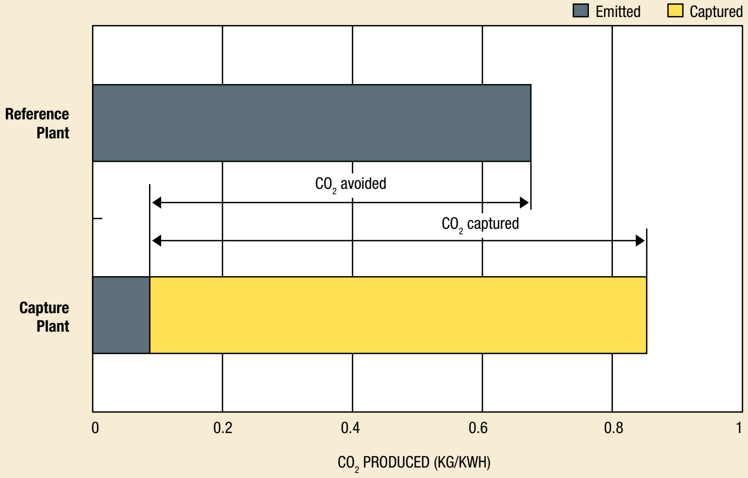
Though the terms storage and sequestration are at times used interchangeably, more accurate is to differentiate on the basis of whether the CO_2 is fixed on a permanent basis, for example by reaction into a mineral form, rather than stored often in a gaseous or liquid state with consequent larger potential 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 3.2-1.

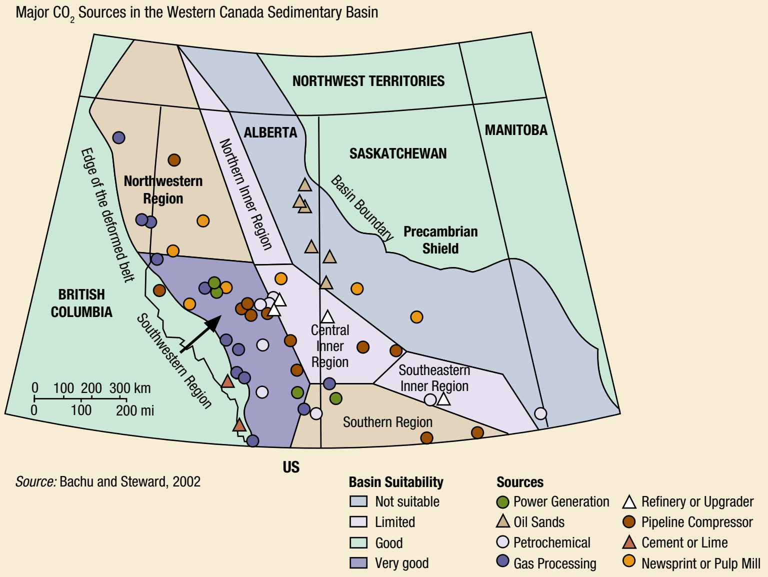
3.2.3 Aquifer

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 3.2-1 Basin Suitability and Sources for CCS (Reynen, 2008)



Source: Bachu and Steward, 2002

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 (commercialized 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 (S_o) and porosity (ø), $S_o ø$	> 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.

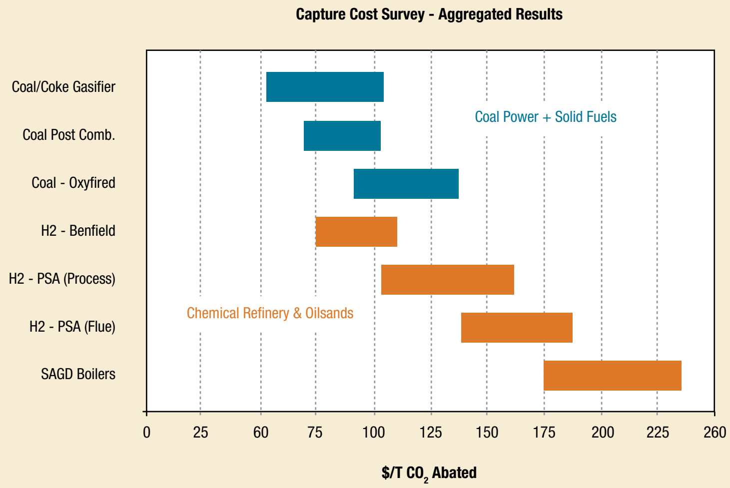
In March 2009, the Alberta Carbon Capture and Storage Development Council published its final report 'Accelerating CCS implementation in Alberta'. It found that CO_2 capture represents 70 to 90 per cent of the overall costs of the CO_2 capture, transport and storage sequence. In addition, it found capture 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.

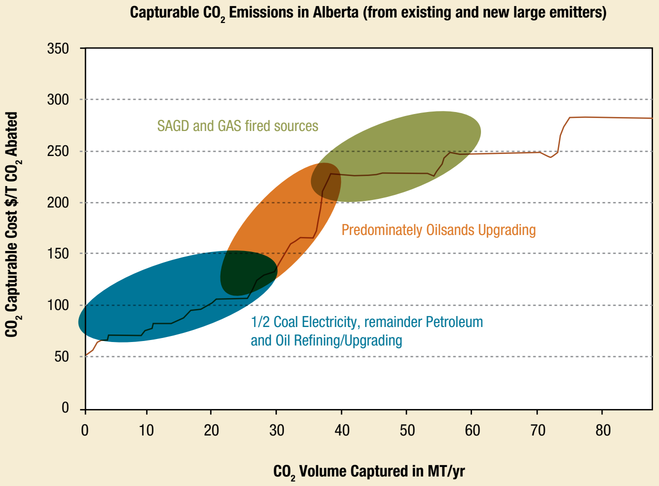
CO_2 Captured – Cost Estimates



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).

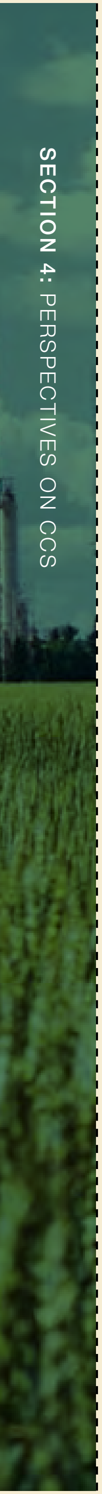
"As a nation, we should not unwisely depend on geologic sequestration to solve all of our problems. Nor should we wait until sequestration is commercially available and cost-effective before moving to make deep cuts in carbon emissions with reliable tools like energy efficiency and renewable energy."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

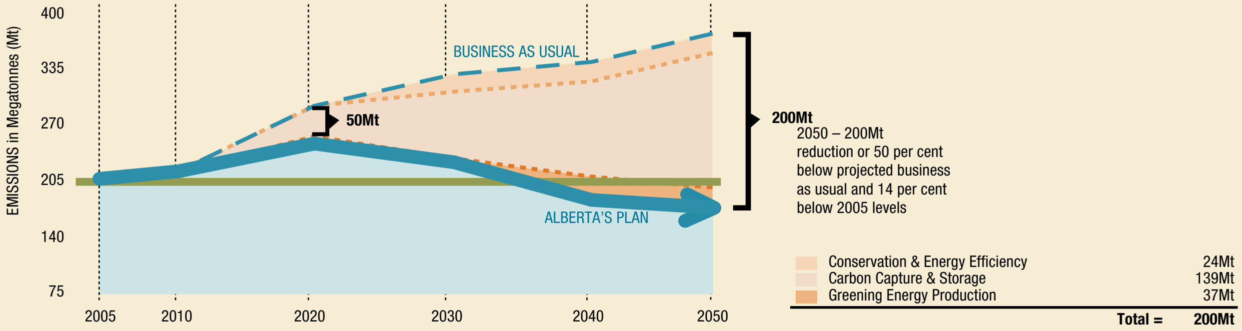
Established by Alberta and Federal Governments in March 2007, the ecoEnergy Carbon Capture and Storage Task Force is mandated to provide advice on how industry and government can together facilitate CCS opportunities. The Force believes that CCS can facilitate up to 40% reduction in the CO_2 emissions 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

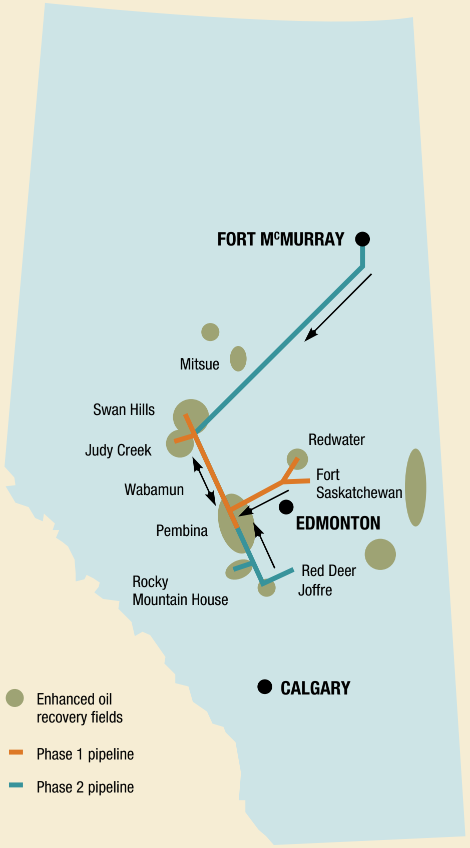
The Integrated CO$_2$ Network (ICO$_2$N) is an alliance of 15 of Canada's largest GHG emitters. The alliance alone accounts for more than 100 Mt of CO$_2$emissions and includes more than 60% of emissions from electricity generation and more than 95% of emissions associated with oil sands production. 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 sectors, which would likely take the form of public subsidies for CCS development and implementation.

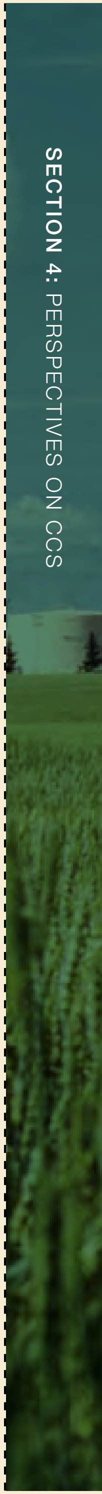
ICO$_2$N was formed to explore the viability of a large-scale Canadian carbon dioxide capture, transportation, and storage network. In December 2007, ICO$_2$N released a report, Carbon Capture and Storage: a Canadian Environmental Superpower Opportunity, which detailed the requirements to implement the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

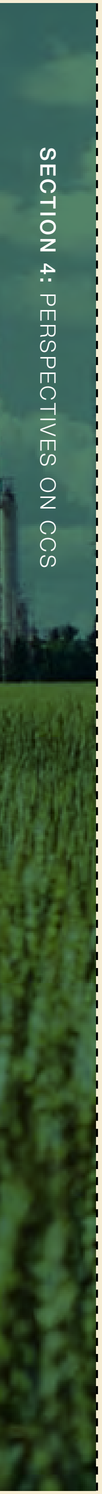
Canadian Natural Resources Limited (CNRL)

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$_2$N (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

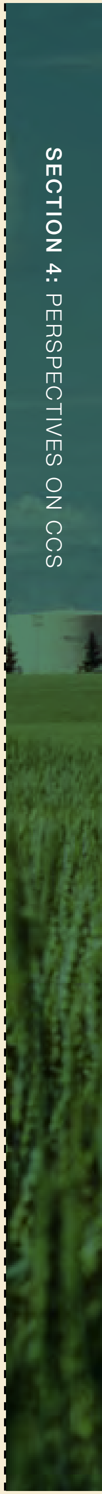
In response to the federal government's proposal for carbon intensity targets in 2010 and for its mandated carbon capture and storage, Petro-Canada has stated that "This solution poses some risks in that CCS has never been implemented on the scale proposed, nor have certain key implementation details 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$_2$N 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).

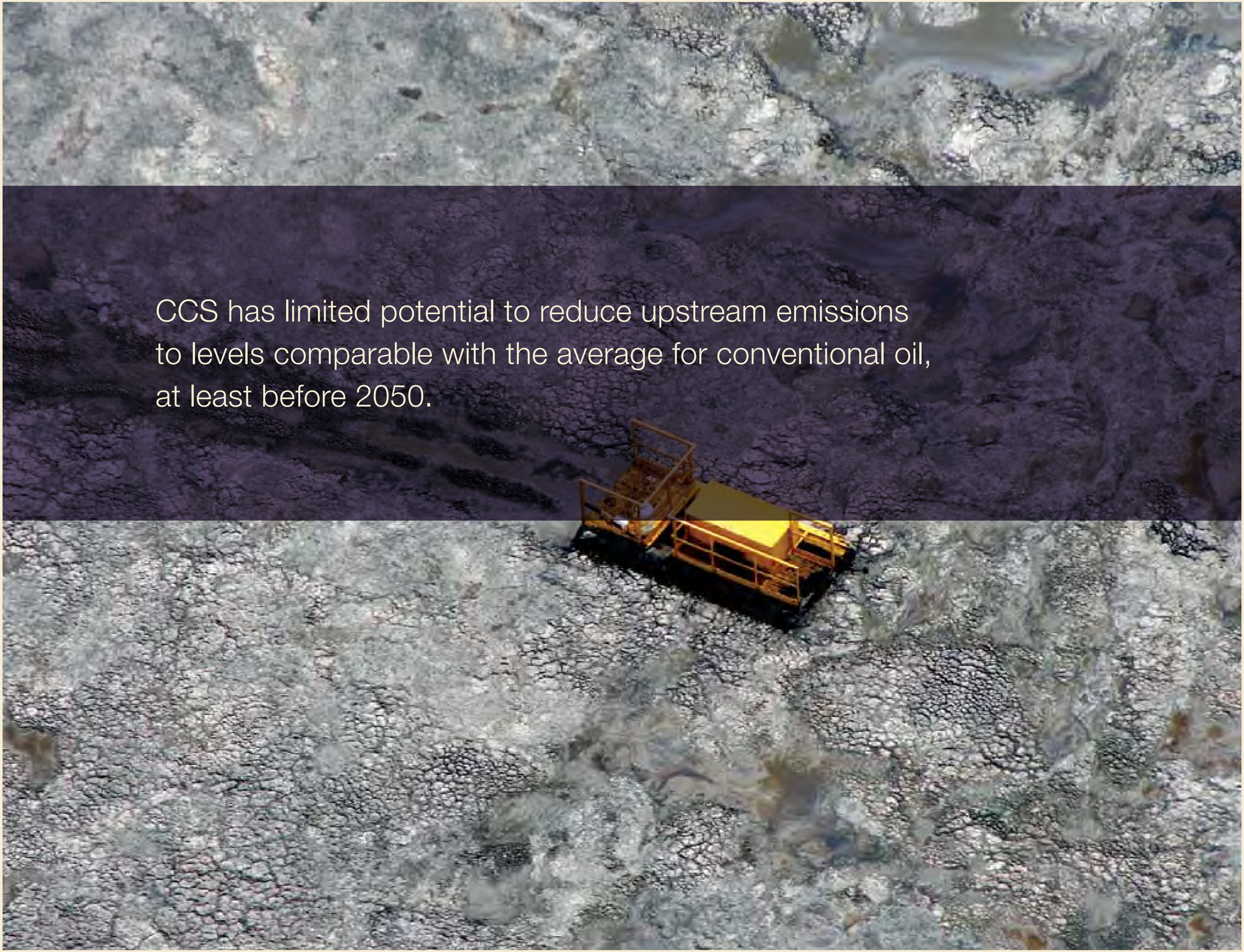
A survey administered by The Pembina Institute in 2008 sought to understand sentiment from various sectors. Respondents were from industry (50), NGOs (20), government (9), and academia (8). While the survey is less representative, of particular interest are the issues raised by the various bodies. Cost 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

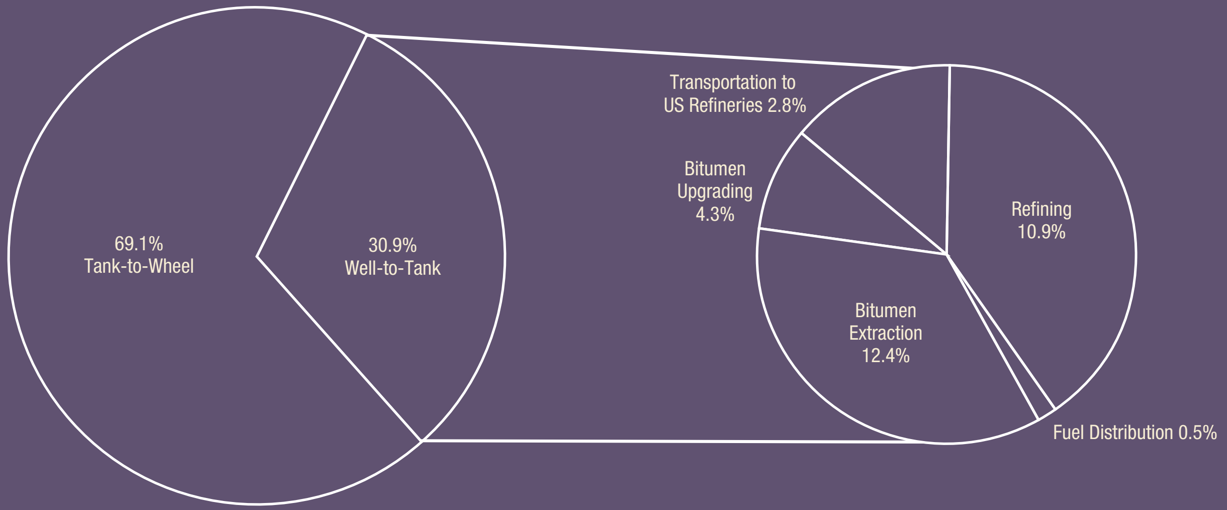
5.1 Technology Readiness of CCS

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

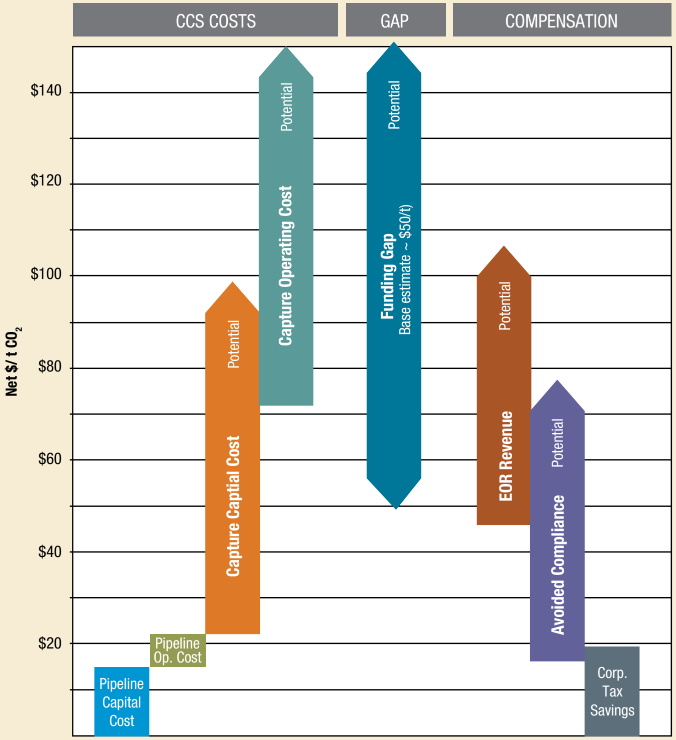
The price of oil has a significant impact on the economic feasibility of CCS technologies. In the last year, the price of oil has dropped as low as $35 per barrel and the impact on oil sands projects has been significant. Oil sands producers are also expected to face greater challenges in the medium 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

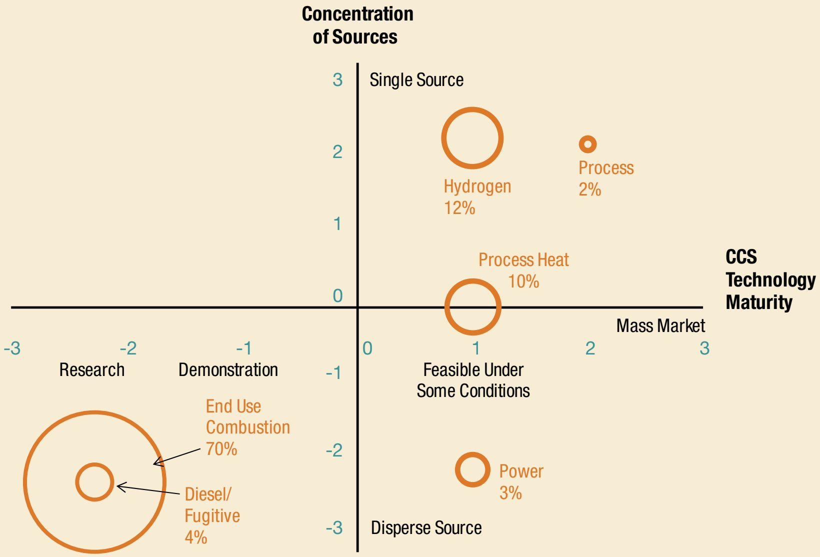
5.3 Opportunities for CCS in Alberta's Oil Sands

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.

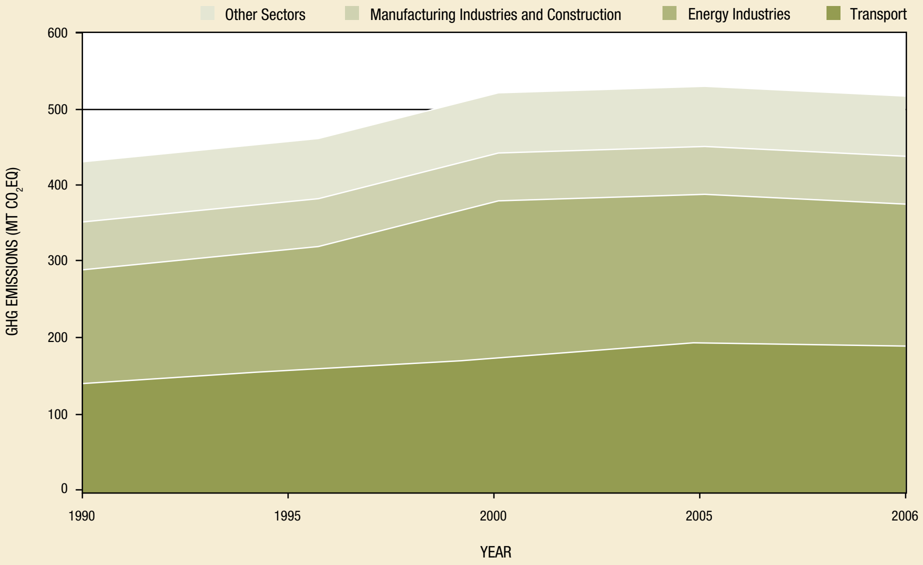
Given that technology for Tank-to-Wheel capture of CO_2 emissions is primitive at best, CCS in the oilsands cannot be considered a mitigation measure with sufficient scope to deal with the magnitude of the issue. Demonstrating this, Figure 5.5-1 shows the contribution of various sectors to Canada's GHG 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 that 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.

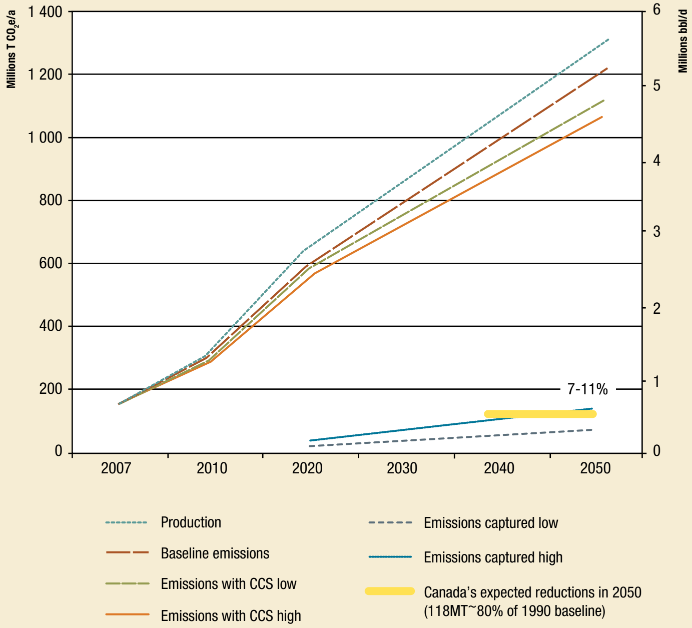


Figure 5.5-2 WTW Emissions of Oilsands Products With and Without CCS

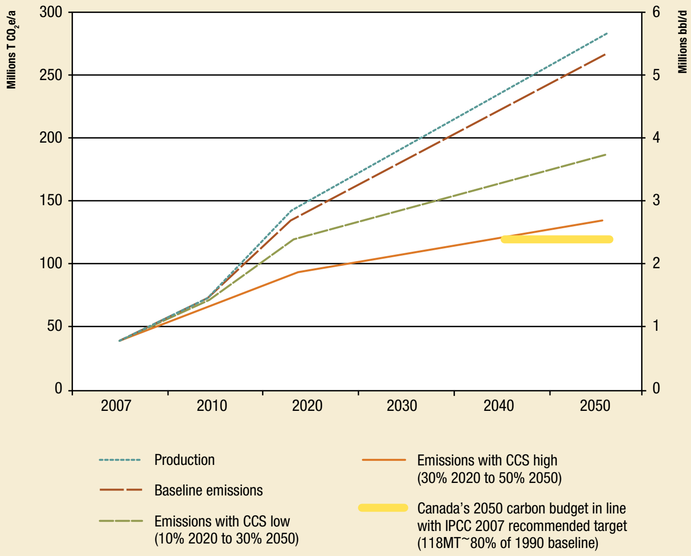


Figure 5.5-3 WTT Emissions from Oilsands With and Without CCS

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.

REFERENCES

Alberta Biodiversity Monitoring Institute (ABMI) *The Status of Birds and Vascular Plants in Alberta's Lower Athabasca Planning Region 2009 Preliminary Assessment*, version 2009-02-01, February 2009. Available at **www.abmi.ca** (June 2009).

Alberta Carbon Capture and Storage Development Council. *Accelerating Carbon Capture and Storage in Alberta: Interim Report*. September 30, 2008.

Alberta Carbon Capture and Storage Development Council. *Accelerating Carbon Capture and Storage Implementation in Alberta: Final Report*. March 2009.

Alberta Energy. February 5, 2009. *What is Oil Sands*. **www.energy.gov.ab.ca/OilSands/793.asp.** (March 2009).

Alberta Energy "Carbon capture and storage: full project proposals" published at **www.energy.gov.ab.ca/Initiatives/1438.asp** (June 2009).

Alberta Environment. *Alberta Environment Report on 2007 Greenhouse Gas Emissions*.

Alberta Government "Investing in our Future: Responding to the Rapid Growth of Oil Sands Development Final Report." December 29, 2006. Accessed at **http://alberta.ca/home/395.cfm** (March 2009).

Alberta Saline Aquifer Project. [Press Release] Alberta Saline Aquifer Project awards key contracts to launch carbon sequestration pilot in early 2009. September 17, 2008. **www.albertaasap.com** (March 2009).

Allen, Erik W. Process water treatment in Canada's oil sands industry: I. Target pollutants and treatment objectives. *J. Environ. Eng. Sci. 7*: 123-138, 2008.

Anderson, J. D. (2008) "CO2 mitigation costs for Canada and the Alberta oil sands" MIT, USA, MSc thesis.

Bang, N.C. (2008) "Carbon Capture and Sequestration, the technology that will allow Canada to develop the Alberta Oil Sands, and meet its Kyoto Targets?" Roskilde University, Denmark, MSc thesis.

Benson, S. "Safety and Monitoring of CO2 Storage Projects" Presentation notes to Sustainable Development and CSS, New York, NY September 10-11, 2007. Available at **http://pangea.stanford.edu/research/bensonlab/presentations/** (June 2009).

Bergerson, J. and Keith, D. "Life Cycle Assessment of Oil Sands Technologies" published by Institute for Sustainable Energy, Environment and Economy, November 2006.

Baer, Paul. "An Issue of Scenarios: Carbon Sequestration as Investment and the Distribution of Risk" in *Climatic Change*, 59: 283-291, 2003.

Beynon, Eric. Director, Strategy and Policy, the Integrated CO2 Network, Calgary. [Letter to the Editor]. National Post. March 9, 2009.

Brandt, A. R., and Farrell, A. E. "Scraping the bottom of the barrel: greenhouse gas emission consequences of a transition to low-quality and synthetic petroleum resources" in *Climatic Change* 84: 241-263, 2007.

Canadian Association of Petroleum Producers. *Canada's Oil, Natural Gas and Oil Sands Overview and Outlook*. February 2009.

Canadian Association of Petroleum Producers. *Challenges and Progress in Canada's Oil Sands*. April 2008.

Canadian Owners Association of Alberta. Industrial Construction Projects >100 MM Cdn (2008Q4-2015Q4). February 13, 2009.

Chadwick, A. et. al. "Geological monitoring of the CO2 Plume at Sleipner, North Sea" in Lombardi et. al. (eds.) Advances in the Geological Storage of Carbon Dioxide, 303-314, 2006.

Charpentier, A.D., Bergerson, J.A., and MacLean, H.L. "Understanding the Canadian oil sands industry's greenhouse gas emissions" in *Environ. Res. Lett.* January-March 2009.

CNRL. "Delivering the Future through Responsible Operations" 2007 Stewardship Report to Stakeholders.

Colt Engineering Corporation. “Greater Edmonton Area Bitumen Upgrader Supply Chain Study”, March 31, 2007.

Cooper, C., “A Technical Basis for Carbon dioxide Storage”. Published by the CO^2 Capture Project.

Cryderman, Kelly. “Oilsands opts out of carbon capture.” *Calgary Herald.* April 2, 2009.

ecoENERGY Carbon Capture and Storage Task Force. *Canada’s Fossil Energy Future: The Way Forward on Carbon Capture and Storage.* January 9, 2008. Report to The Minister of Alberta Energy, The Minister of Natural Resources Canada.

Damm, D.L., Fedorov, A.G. “Conceptual study of distributed CO^2 capture and the sustainable carbon economy” in *Energy Conversion and Management* 49: 1674-1683, 2008.

Dunbar, R.B. Existing and Proposed Canadian Commercial Oil Sands Projects. Strategy West Inc. February 2009.

Dyer, S. et. al. “Under-Mining the Environment: the Oil Sands Report Card” published the Pembina Institute/WWF-Canada, January 2008 available at **www.pembina.org/pub/1571** (accessed 03/09).

Dyer, S.J., O’Neill, J. P., Wasel, S. M., Boutin, S., “Avoidance of industrial development by woodland caribou” in *Journal of wildlife management* 65(3):531-542, 2001.

Dyer, S., Severson-Baker, C. Alberta’s Oil Sands Just Got Dirtier Media Release published Feb 13, 2009 at **http://alberta.pembina.org/media-release/1783**.

Enkvist, P. et al., “A cost curve for greenhouse gas reduction” in *The McKinsey Quarterly* 2007, Number 1.

Environment Canada. *Canada’s Greenhouse Gas Emissions: Understanding the Trends*. November 2008.

Environment Canada. *Information on Greenhouse Gas Sources and Sinks*. May 2008 available at **www.ec.gc.ca/pdb/ghg/inventory_report/2006/som-sum_eng.cfm (accessed 04/09)**.

Environment Canada. *National Inventory Report: Greenhouse Gas Sources and Sinks in Canada 1990-2007*. Submission to the United Nationals Framework Convention on Climate Change. April 2009.

Environmental Research and Studies Centre (ERSC) “Running out of Steam? Oil Sands Develoipment and Water use in the Athbasca River-Watershed: Science and market based Solutions” published by the Munk Centre for International Studies, University of Toronto and the Environmental Research and Studies Centre, University of Alberta, May 2007.

Price, M. “11 million litres a day: the tar sands’ leaking legacy” published by Environmental Defence, December 2008. Available from **www.environmentaldefence.ca**.

Gardner, T., *Canada must look beyond carbon burial: CAPP* by Reuters June 3rd, 2008, available at **www.reuters.com/article/GlobalEnergy08/idUSN0359779020080603** (accessed 03/09).

Gilbert, R. & Pearl, A. “Energy and Transport Future” Prepared for the round Table on Environment and Economy, June, 2005. Available at **www.richardgilbert.ca/Files/2005/Energy%20and%20Transport%20Futures%20(Web).pdf**.

Government of Alberta. *Alberta’s 2008 Climate Change Strategy*. January 2008.

Grant, J., Dyer, S., Woynillowicz, D. “Fact or Fiction? Oil sands reclamation” The Pembina Institute, May 2008.

Griffiths, M., Cobb, P. and Marr-Laing, T. November, 2005. “Carbon Capture and Storage: An arrow in the quiver or a silver bullet to combat climate change? A Canadian Primer” published by The Pembina Institute. **http://pubs.pembina.org/reports/CCS_Primer_Final_Nov15_05.pdf** (March 2009).

Griffiths, M. And Woynillowicz, D. *Heating Up in Alberta: Climate Change, Energy Development and Water*. The Pembina Institute. February 2009. **http://pubs.pembina.org/reports/heating-up-in-alberta-report.pdf** (May 2009).

Hatch, C. and Price, M. “Canada’s Toxic Tar Sands: The Most Destructive Project on Earth”, Toronto: Environmental Defence, February 2008.

Hamilton, Tyler “Don’t bet farm on a greener champion” interview in the Toronto Star, March 30, 2009 available at **www.thestar.com/printArticle/610261** (June 2009).

Holloway, S. Sequestration – the Underground Storage of Carbon Dioxide. *Climate Change and Energy Pathways for the Mediterranean*, pgs. 61-88, 2008.

Holroyd, P., Simieritsch, T., “The waters that bind us: transboundary implications of oil sands development” The Pembina Institute, February 2009.

Humpries, Marc. *North American Oil Sands: History of Development, Prospects for the Future*. Congressional Research Service. Updated January 17, 2008.

Imperial Oil, Kearl Oil Sands project website, Environment-Air Quality heading **www.imperialoil.ca/Canada-English/ThisIs/Operations/TI_O_Kearl_Air.asp**. Retrieved March 25, 2009.

ICO_2N. *Carbon Capture & Storage: A Canadian Environmental Superpower Opportunity*. December 2007.

IPCC Special report on Carbon Dioxide Capture and Storage, Summary for Policymakers. 2005, available from **www.ipcc.ch/pdf/special-reports/srccs/srccs_summaryforpolicymakers.pdf** (June 2009).

Jordaan, S.M., Keith, D. W., Stelfox, B. *Quantifying land use of oil sands production: a life cycle perspective*. Environ. Res. Lett. 4 (2009) pg. 15.

IPCC 2007 4th Assessment Report, Working Group III Report Mitigation of Climate Change, 2007.

Kovscek, A. R. “Screening Criteria for CO2 Storage in Oil Reservoirs.” *Petroleum Science and Technology* (2002). 20:7&8, 841-866.

Kraemer, D. et. al. “Solar assisted method of recovery of bitumen from oil sand in *Applied Energy* (2009) doi:10.1016/j.apenergy.2008.12.003 (in press).

Levi, M. A. “The Canadian Oil Sands: Energy Security vs. Climate Change” Council Special Report No. 47. Council on Foreign Relations at the Centre for Geoeconomic Studies, May 2009.

Lister, A. Nero, V., Farwell, A., Dixon, D.G., Van Der Kraak, G., “Reproductive and stress hormone levels in goldfish (Carassius auratus) exposed to oil sands process-affected water” in *Aquatic Toxicology* 87:170-177, 2008.

Maxwell, Gary R. (2004). Synthetic Nitrogen Products. Springer.

McColl David (February 2009). The Eye of the Beholder: Oil Sands Calamity or Golden Opportunity? CERI. **www.ceri.ca/documents/CERIOilSandsBriefingFebruary2009.pdf**. Retrieved March 9, 2009.

McCoy, S. & Ruin, E. ‘Models of CO2 transport and storage costs and their importance in CCS cost estimates’ in *Fourth Annual Conference on carbon capture and sequestration DOE/NTL proceedings*. May 2005.

McKinsey & Company *Carbon Capture and Storage: Assessing the economics accessed* at **www.mckinsey.com/clientservice/ccsi/pdf/CCS_Assessing_the_Economics.pdf**. Retrieved March 9, 2009.

Mui, S., Hannah, D. And Hwang, R. [White Paper]. *Life Cycle Analysis of Greenhouse Gas Emissions from Tar Sands*. Natural Resources Defense Council. November 18, 2008.

National Energy Board. *Canada’s Oil Sands – Opportunities and Challenges to 2015: An Update*. June 2006. **www.neb.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/lsnd/pprtntsndchllngs 20152006/pprtntsndchllngs20152006-eng.pdf**.

National Energy Technology Laboratory. *An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions*. DOE/NETL-2009/1362. March 27, 2009.

National Energy Technology Laboratory. *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels.* November 26, 2008.

North Sea Basin Task Force. *Storing CO2 under the North Sea Basin: A key solution for combating climate change*. June 2007.

Ordorica-Garcia, G. Croiset, E., Douglas, P., Elkamel, A. and Gupta, M. "Modeling the Energy Demands and Greenhouse Gas Emissions of the Canadian Oil Sands Industry" in *Energy & Fuels*, 21:2098-2111, 2007.

Ordorica-Garcia, et al. Modeling the Energy Demands in the Greenhouse Gas Emissions of the Canadian Oil Sands Industry. Energy Fuels. June 1, 2007. 21(4): 2098-2111.

The Pembina Institute. February 19, 2009. The Pembina Institute's Perspective on Carbon Capture and Storage (CCS). **http://pubs.pembina.org/reports/pembina-perspective-ccs-feb-19-09.pdf** (March 2009).

Petro-Canada. Air. 2009. **www.petro-canada.ca/en/environsociety/4700.aspx** (March 2009).

Petro-Canada. Risks and Opportunities. 2009. **www.petro-canada.ca/en/environsociety/4580.aspx** (March 2009).

Polczer, Shaun. "Upgrader Alley projects toppling like dominoes" in *Calgary Herald*, January 31, 2009. Available at **www.calgaryherald.com/Upgrader+Alley+projects+toppling+like+dominoes/1239493/story.html** (June 2009).

Reddy et al. Fluor's Econamine FG Plus^{SM} Technology: An Enhanced Amine-Based CO^2 Capture Process. Fluor. Presentation to Second National Conference on Carbon Sequestration, National Energy Technology Laboratory/Department of Energy. May 5-8, 2003.

Reynen, Bill. *CO$_2$ Storage Potential in Canada*. Natural Resources Canada. January 22, 2008.

Rhodes, J. S. and Keith, D. "Biomass with Capture: negative emissions within social and environmental constraints" *Climactic Change* issue 87:321-328, 2008.

Riding, J.B. The IEA Weyburn CO^2 Monitoring and Storage Project. *Advances in the Geological Storage of Carbon Dioxide*. 2006. 223-230.

Robertson, K., Findsen, J., and Messner, S. "International Carbon Capture and Storage Projects: Overcoming Legal Barriers" published by National Energy Technology Library. June 23, 2006.

Sandborn, T. "Law Suit a Tar Sands Stopper? Win for Alberta Cree band could clog up oil ambitions" 28 Jul 2008, **TheTyee.ca**

Schmidt, L., "Big Oil's Big Change" *Calgary Herald*, February 7, 2009. Available from **www.calgaryherald.com/story_printhtml?id=1264880** (June 2009).

Schnitzer, H., Brunner, C., Gwehenberger, G., "Minimizing greenhouse gas emissions through the application of solar thermal energy in industrial processes" in *Journal of Cleaner Production* 15: 1271-1286, 2007.

Secret advice to politicians: oilsands emissions hard to scrub. Briefing document is pessimistic on carbon storage and capture. *CBC News*. November 24, 2008.

Sharp, J., "Carbon Capture and Storage: The Views of the Canadian Public" published by The Pembina Institute, October 2008. Available from **http://pubs.pembina.org/reports/ccs-discuss-public-views.pdf** (June 2009).

Sharp, J. "Carbon Capture and Storage: Online Survey of Sector Experts" discussion paper published by The Pembina Institute, October 2008. **http://pubs.pembina.org/reports/ccs-discuss-online-opinion.pdf** (June 2009).

Shell. *Responsible energy: The Shell Sustainability Report 2008*. Available from **www.shell.com/home/content/responsible_energy/sustainability_reports** (June 2009).

Shell Canada *Shell Quest: Carbon Capture& Storage* Public disclosure document available from **www.shell.ca/home/content/ca-en/about_shell/what_we_do/oil_sands/quest/dir_quest.html accessed**. June 6, 2009.

Shinar, R. Francesco, C. (2009) "Solar Thermal Energy: the forgotten energy source" in *Techology in Society*, 261-270.

Siddique, T., Gupta, R., Fedorak, P.M., MacKinnon, M. D., Foght, J. "A first approximation kinetic model to predict methane generation from oil sands tailings settling basin" in *Chemosphere* 72: 1573-1580, 2008.

Sierra Club. [Fact Sheet]. April 2008. The Basics of Carbon Capture and Sequestration. **www.sierraclub.org/energy/factsheets/basics-sequestration.pdf** (March 2009).

StatOilHydro. 2008. *Annual and Sustainability Report*. **www.statoilhydro.com** (April 2009).

Stone, B. Mednick, A.C. Holloway, T and Spak, S (2009) "Mobile source mitigation through Smart Growth Development and Vehicle Fleet Hybridization' in *Environmental Science and Technology*, vol. 43, no.6.

Sturgess, K. P. "A 2020 fresh water neutral upstream petroleum industry: feasibility study 1730 v.3" published by Alberta Energy Research Institute, March 2008.

Suncor Energy. *A closer look at our journey toward sustainable development. Sustainability Report 2007*. Available from **www.suncor.com/doc.aspx?id=115** (June 2009).

Suzuki, David. February 27, 2009. Are we digging ourselves into a hole with carbon capture? **www.davidsuzuki.org/about_us/Dr_David_Suzuki/Article_Archives/weekly02270901.asp** (March 9, 2009).

Syncrude Canada 2007. *Sustainability Report*. Available from **http://sustainability.syncrude.ca/sustainability2007** (June 2009).

Tolley, R. Ed. (1990) The Greening of Urban Transport: walking and cycling in western cities. Wiley and Sons, New York.

Toman, M., Curtright, A.E., Ortiz, D.S., Darmstadter, J., Shannon, B. "Unconventional Fossil-Based Fuels Economic and Environmental Trade-Offs." RAND Corporation 2008.

Veawab et al. "Solvent Formulation for CO$_2$ Separation from Flue Gas Streams" in proceedings from 2001 Conference on Carbon Sequestration.

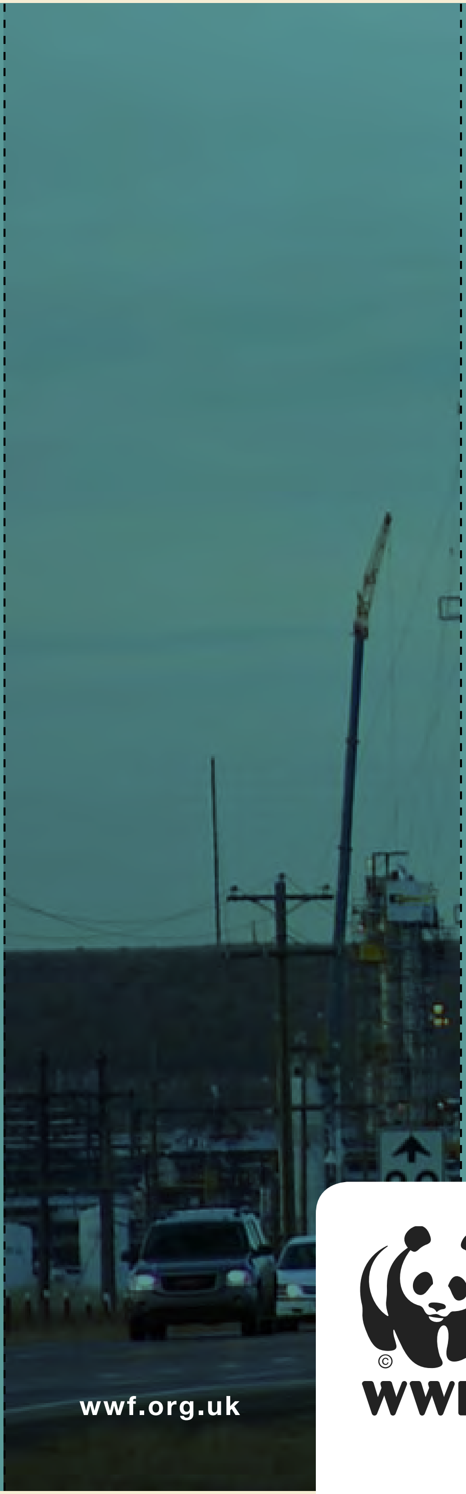
Witter, R., Stinson, K., Sackett, H., Putter, S., Kinney, G., Teitelbaum, D., Newman, L. "Potential exposure-related human health effects of oil and gas developments: a white paper" Colorado School of public health, September 15, 2008.

Working Group III of the Intergovernmental Panel on Climate Change. *Carbon Dioxide Capture and Storage*. Cambridge University Press, 2005.

World Wildlife Fund. *Climate Solutions: WWF's Vision for 2050* available from **http://assets.panda.org/downloads/climatesolutionweb.pdf** (June 2009).

Woynillowicz, Dan, "The Energy and Global Warming Implications of Canadian Tar Sands Development." Presentation notes from August 26-27, 2008 by The Pembina Institute available at **http://assets.wwf.no/downloads/the_energy___global_warming_implications_of_tar_sands_development.ppt** (June 2009).

Zedtwitz, P.v., Petrasch, J., Trommer, D. and Steinfeld, A. "Hydrogen production via solar thermal decarbonization of fossil fuels" in *Solar Energy* 80: 1333-1337, 2006.



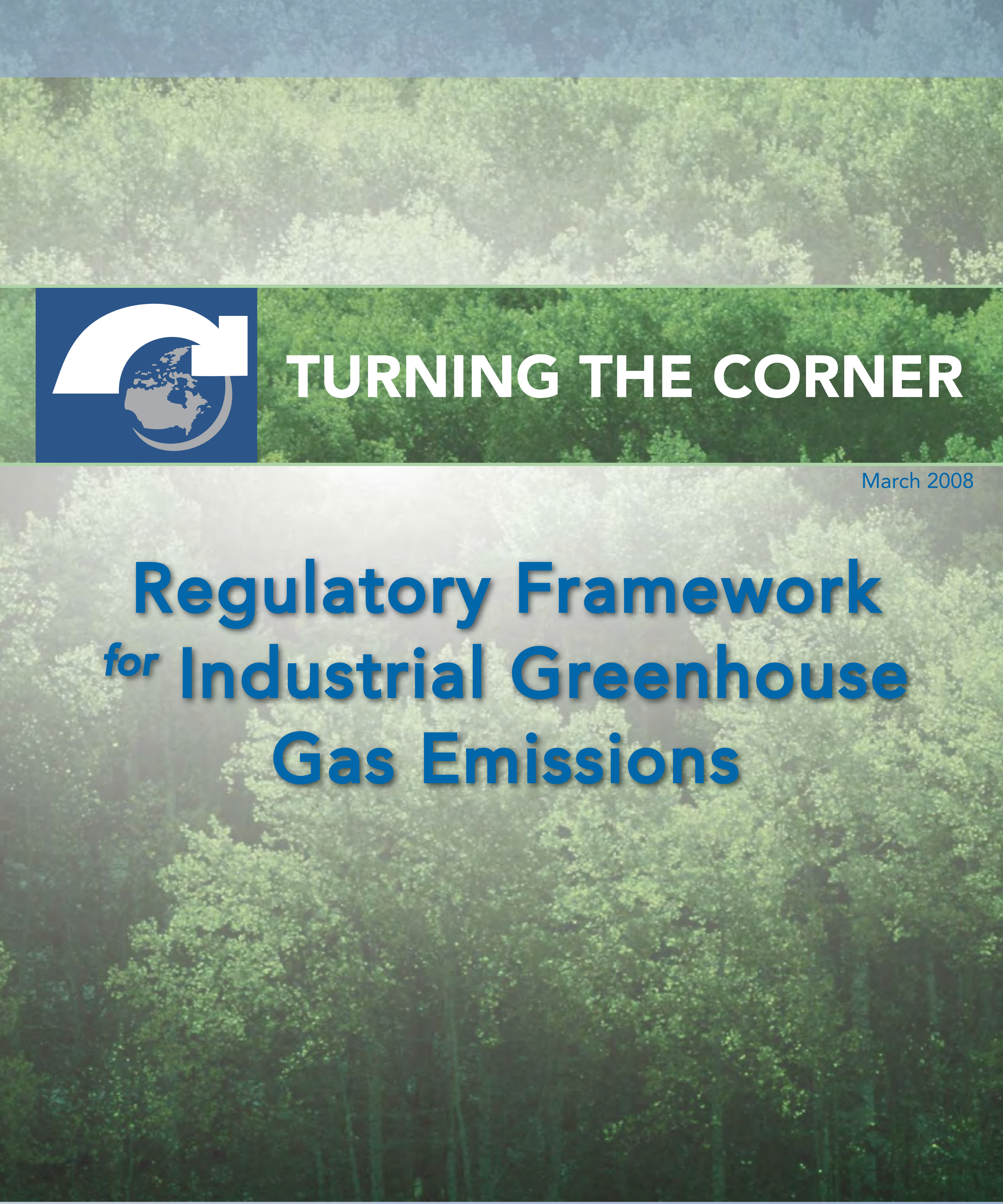
wwf.org.uk

WWF

The **co-operative** bank
insurance
investments

The mission of the international WWF network is to stop the degradation of the planet's natural environment and to build a future in which humans live in harmony with nature, by

- conserving the world's biological diversity
- ensuring that the use of renewable natural resources is sustainable
- reducing pollution and wasteful consumption



TURNING THE CORNER

March 2008

Regulatory Framework for Industrial Greenhouse Gas Emissions

Government of Canada
Gouvernement du Canada

Canada

For more information:

www.ecoaction.gc.ca

1 800 O-Canada

(1-800-622-6232, or TTY 1-800-926-9105)

Catalogue no.: En84-60/2008
ISBN 978-0-662-05525-9

Library and Archives Canada Cataloguing in Publication

Regulatory framework for industrial greenhouse gas emissions.

Text in English and French on inverted pages.
Title on added t.p.: Cadre réglementaire sur les émissions industrielles de gaz à effet de serre.
Available also on the Internet.
ISBN 978-0-662-05525-9
Cat. no.: En84-60/2008

1. Air--Pollution--Law and legislation--Canada. 2. Air—Pollution --Government policy--Canada. 3. Air quality management--Government policy--Canada. 4. Greenhouse gas mitigation--Government policy--Canada. 5. Industries--Environmental aspects--Canada. I. Canada. Environment Canada II. Title: Cadre réglementaire sur les émissions industrielles de gaz à effet de serre.

TD883.148.C3F56 2008 344.7104’6342 C2008-980050-8E

Printed on recycled paper using vegetable-based ink.

Table of contents

Overview

- The April 2007 *Regulatory Framework for Air Emissions* laid out the broad design of the regulations for industrial emissions of both greenhouse gases and air pollutants.
- This document sets out the final regulatory framework for industrial greenhouse gas emissions. It includes both an elaboration and a strengthening of the April 2007 regulatory framework.
- The federal government still intends to work to reach equivalency agreements with any interested provinces that set enforceable provincial emission standards that are at least as stringent as the federal standards.
- The final regulatory framework will contribute significantly to the commitment in the 2007 Speech from the Throne to implement a national strategy to reduce Canada's total greenhouse gas emissions by 20% below 2006 levels by 2020.

Strengthening of the April 2007 regulatory framework

- **The final regulatory framework strengthens the April 2007 regulatory framework in three key respects**
    - All oil sands upgraders and in-situ plants that come into operation in 2012 or after will be required to meet a stringent target based on the use of carbon capture and storage by 2018.
    - All coal-fired electricity plants that come into operation in 2012 or after will be required to meet a stringent target based on the use of carbon capture and storage by 2018.
    - The federal government will establish a clean electricity task force to work with provinces and industry to meet an additional 25 Mt reduction goal from the electricity sector by 2020.

Elaboration of April 2007 regulatory framework: targets

- All covered industrial sectors will be required to reduce their emissions intensity from 2006 levels by 18% by 2010, with 2% continuous improvement every year after that.
- The target will be applied at the facility, sector, or corporate level, as determined after consultations with each sector.
- Minimum thresholds will be set in five sectors to avoid imposing unreasonable administrative costs on small facilities.
- Fixed process emissions will receive a 0% target. The definition of fixed process emissions will be based on technical feasibility.
- To provide incentives to adopt the best available technologies for new facilities, whose first year of operation is 2004 or later, a target based on a cleaner fuel standard will be applied.

- There will be an incentive until 2018 for facilities to be built carbon-capture ready.
- A special incentive will be provided through the target structure for high-efficiency co-generation.

Elaboration of April 2007 regulatory framework: compliance mechanisms

- *Canada's domestic offset system:*
    - The offset system will issue credits for incremental real, verified domestic reductions or removals of greenhouse gas emissions in activities outside the regulations.
    - Offset credits may be used by regulated firms for compliance with their targets.
    - The offset system will be administered in a cost–effective manner and will promote projects in as many sectors and for as many project types as practical.
- *Clean Development Mechanism:*
    - Firms may use credits from the Kyoto Protocol's Clean Development Mechanism (with the exception of credits for forest sink projects) for up to 10% of their regulatory obligation.
- *Credit for Early Action Program*:
    - Firms that took verified early action to reduce emissions will be eligible for a total one-time allocation of 15 Mt in credits. These credits will be bankable and tradable, and will be allocated based on clear criteria and a simple, transparent process.
- *Technology fund:*
    - Subject to the conditions set out in the April 2007 regulatory framework, firms will be able to make contributions to a technology fund as a means of complying with the regulations.
    - The technology fund will take a portfolio approach to investing in a range of technology deployment and development projects; the technology fund will own the emission reductions resulting from its investment, based on the cost of the project.
    - Subject to equivalent conditions as apply to the technology fund, firms will be able to invest directly in pre-certified investment projects, drawing from a menu of projects established by the federal government.
    - In order to ensure that carbon capture and storage is in widespread use by 2018, firms in sectors that can make use of this technology may be credited for investments in pre-certified carbon-capture-and-storage projects up to 100% of their regulatory obligation through 2017.

Emission reductions

The regulatory framework is expected to achieve approximately 165 Mt in direct and indirect emission reductions from the industrial sector by 2020; that is, about a 37% reduction from projected levels or a 21% reduction below 2006 levels. This does not include the additional 25 Mt in targeted reductions from the electricity sector.

Next steps

- The regulatory framework for industrial greenhouse gas emissions will now be translated into regulatory language. Draft regulations are expected to be published in the *Canada Gazette, Part I* for public comment in fall 2008.
- Final regulations are expected to be approved and published in the *Canada Gazette, Part II* in fall 2009. The greenhouse gas provisions of the regulations are to come into force, as planned, on January 1, 2010.
- Air pollutant elements will be added to the draft regulations once the regulatory framework for air pollutants has been finalized in spring 2008.

1. Introduction

On April 26, 2007, the Government of Canada released *Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution*.[1] This plan set out an ambitious agenda to improve the environment and the health of Canadians through a series of concrete, innovative measures to reduce emissions of greenhouse gases and air pollutants. Rather than relying solely on the voluntary measures used in the past, for the first time, the government is introducing mandatory and enforceable actions across a broad range of sectors.

In addition, the government committed to reducing Canada's total emissions of greenhouse gases, relative to 2006 levels, by 20% by 2020 and by 60% to 70% by 2050.

The *Turning the Corner* action plan has several components, including:

- a regulatory framework for industrial emissions of greenhouse gases and air pollutants;
- the development of a mandatory fuel-efficiency standard for automobiles, beginning with the 2011 model year, as well as action to reduce emissions from the rail, marine, and aviation sectors, and from on-road and off-road vehicles and engines;
- the implementation of new energy performance standards to strengthen existing energy-efficiency standards for a number of products that consume electricity, including light bulbs, in order to reduce emissions from the use of consumer and commercial products; and
- the development of measures to improve indoor air quality.

Since the release of the *Turning the Corner* action plan, the Government of Canada has made significant progress in all of these areas.

The April 2007 regulatory framework, entitled *Regulatory Framework for Air Emissions*, laid out the broad design of the regulations for industrial emissions of both greenhouse gases and air pollutants.[2] This document provides a detailed description of the final regulatory framework for industrial greenhouse gas emissions. The framework for industrial emissions of air pollutants will be finalized in spring 2008.

Section 2 summarizes the broad regulatory framework for industrial greenhouse gas emissions as set out in April 2007 in the *Regulatory Framework for Air Emissions*. In Section 3, a brief overview of the consultations undertaken is provided. In Sections 4 and 5, the final greenhouse gas regulatory framework is elaborated, first with respect to the application of the target and, secondly, with respect to the design of the compliance mechanisms. Section 6 reiterates the government's intention to move from an emission-intensity based system to a fixed emission cap system in the future. In Section 7, a summary of the estimated economic impacts of the regulations on industrial greenhouse gases is given. Section 8 outlines the steps in finalizing the regulations.

---

[1] The full set of measures in *Turning the Corner* is available at www.ecoaction.gc.ca/turning-virage/index-eng.cfm.

[2] The April 2007 regulatory framework for air emissions, including industrial emissions, is available at www.ecoaction.gc.ca/news-nouvelles/20070426-1-eng.cfm

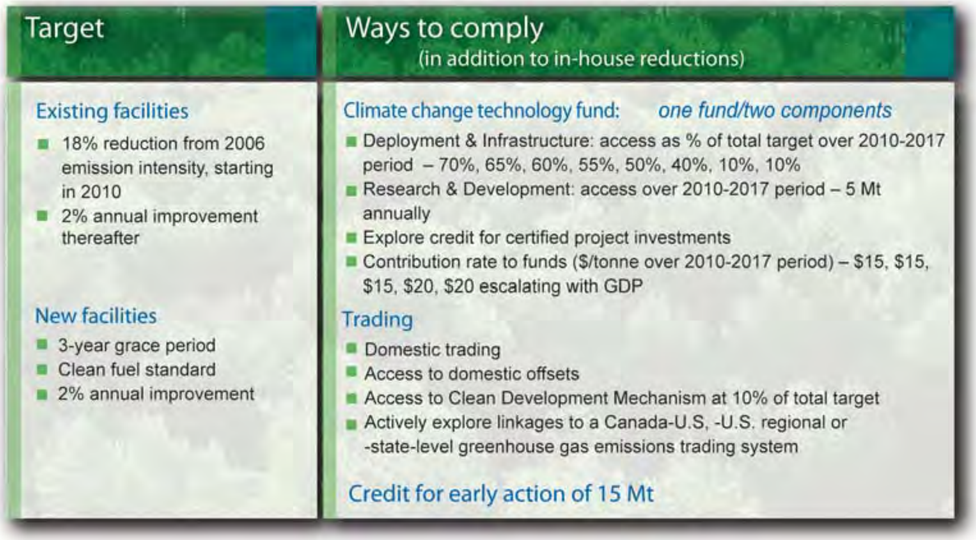
2. The April 2007 Regulatory Framework for Industrial Greenhouse Gas Emissions

The regulatory framework for industrial greenhouse gas emissions proposed that the following sectors would be covered by the regulations:

- electricity generation produced by combustion;
- oil and gas (including oil sands, upstream oil and gas, natural gas pipelines, and petroleum refining);
- pulp and paper;
- iron and steel;
- iron ore pelletizing;
- smelting and refining (including base metals smelting, aluminum and alumina, and ilmenite (titanium) smelting);
- cement;
- lime;
- potash; and
- chemicals and fertilizer.

The targets for greenhouse gas emissions will set reductions in emission intensity from 2006 levels that will come into force in 2010. The government has committed to review the regulations every five years in order to assess progress in reaching the government's medium- and long-term emission reduction objectives. The first such review would take place in 2012 and would entail an assessment of the effectiveness of measures taken to reduce greenhouse gas emissions and of advances in industrial technology in order to determine the potential for further emission reductions.

The framework for industrial greenhouse gas emissions has two key components: (1) stringent, mandatory short-term emission-intensity reduction targets, relative to 2006 emissions and (2) compliance mechanisms that provide firms with flexibility in how they meet their targets. Each of these components will be addressed in turn.



Target

Existing facilities
- 18% reduction from 2006 emission intensity, starting in 2010
- 2% annual improvement thereafter

New facilities
- 3-year grace period
- Clean fuel standard
- 2% annual improvement

Ways to comply
(in addition to in-house reductions)

Climate change technology fund: *one fund/two components*
- Deployment & Infrastructure: access as % of total target over 2010-2017 period – 70%, 65%, 60%, 55%, 50%, 40%, 10%, 10%
- Research & Development: access over 2010-2017 period – 5 Mt annually
- Explore credit for certified project investments
- Contribution rate to funds ($/tonne over 2010-2017 period) – $15, $15, $15, $20, $20 escalating with GDP

Trading
- Domestic trading
- Access to domestic offsets
- Access to Clean Development Mechanism at 10% of total target
- Actively explore linkages to a Canada-U.S, -U.S. regional or -state-level greenhouse gas emissions trading system

Credit for early action of 15 Mt

2.1 Targets

The April 2007 framework set an initial required reduction of 18% from 2006 emission-intensity levels in 2010 for existing facilities. Every year thereafter, a 2% continuous improvement in emission intensity would be required. By 2015, therefore, an emission-intensity reduction of 26% from 2006 levels would be required, with a further reduction to 33% by 2020. The emission-intensity approach ties the emission reduction targets to production. This allows emission reductions to be achieved while accommodating economic growth.

New facilities, which are those whose first year of operation is 2004 or later, would be granted a three-year commissioning period before they would face an emission-intensity reduction target. After the third year, new facilities would be required to improve their emission intensity each year by 2%. A cleaner fuel standard would be applied, thereby setting the target as if they were using the designated fuel. A flexible approach would be taken in special cases where the equipment or technology used in a new plant facilitates carbon capture and storage or otherwise offers a significant and imminent potential for emission reductions.

The purpose of this policy is to provide an incentive for new facilities to choose cleaner fuels or to invest in the technology needed for carbon capture and storage or in other less emission-intensive technologies.

For both existing and new facilities, fixed process emissions, which are emissions tied to production and for which there is no alternative reduction technology, would receive a 0% target in the regulations. In other words, for these types of emissions, there is no way, with current technology, for them to be reduced except by shutting down production.

2.2 Compliance mechanisms

In order to provide flexibility and to minimize the economic impact of the regulations, firms could comply with the regulations either by reducing their own emissions through abatement actions or by making use of one of the framework's compliance mechanisms, detailed below.

Technology fund: Firms could obtain credits for compliance purposes by contributing to a technology fund. The fund would be a means to promote the development, deployment, and diffusion of technologies that reduce emissions of greenhouse gases across industry. A third-party entity, at arm's-length from government, would be created to administer the fund. A key principle is that there would be no inter-regional transfer of wealth.

Contributions to the deployment-and-infrastructure component of the fund, aimed at investments with a high likelihood of yielding greenhouse gas emission reductions in the near term, would be limited to 70% of the target in 2010, falling to 65% in 2011, 60% in 2012, 55% in 2013, 50% in 2014, 40% in 2015, 10% in 2016, and 10% in 2017. No further contributions would be accepted after 2017. The research and development component, which would focus on projects aimed at supporting the creation of transformative technologies, would be limited to 5 Mt each year, also ending after 2017.

From 2010 to 2012, the contribution rate for the fund would be $15 per tonne of carbon dioxide equivalent. In 2013, the contribution rate would be $20 per tonne. Thereafter, the rate would escalate yearly at the rate of growth of nominal GDP to 2017.

Inter-firm trading: Firms whose actual emission intensity in a given year is below their target would receive tradable credits equal to the difference between their target and their actual emission intensity, multiplied by their production in that year. These credits could be banked for future use or sold to other parties, including other regulated firms.

Offset System: Offsets are projects that result in incremental real, verified domestic reductions or removals of greenhouse gas emissions in activities that are not covered by the federal greenhouse gas regulations. These projects would generate credits that firms could use for compliance purposes.

Clean Development Mechanism: Firms could use certain credits from the Kyoto Protocol's Clean Development Mechanism. Access to these credits for compliance purposes would be limited to 10% of each firm's total target.

One-time credit for early action: Firms that took verified action between 1992 and 2006 to reduce their greenhouse gas emissions would be eligible to apply for a share of a one-time credit for early action. A maximum of 15 Mt worth of credits would be allocated, with no more than 5 Mt to be used in any one year. Firms would be required to submit evidence of changes in processes or facility improvements they had undertaken that resulted in verifiable, incremental greenhouse gas emission reductions. The maximum allocation for emission reductions would be one credit for each tonne of carbon dioxide equivalent reduction. If the total tonnage of emission reductions applied for were to exceed 15 Mt, the credits would be distributed to individual firms in proportion to their contribution to the total emission reduction achieved.

2.3 Estimated impact of the April 2007 Regulatory Framework for Air Emissions

Application of the industrial regulatory framework is expected to result in significant absolute reductions in greenhouse gas emissions from 2006 levels. This would put Canada on the path to meeting its national emission reduction target of 20% below 2006 levels by 2020.

Under the April 2007 analysis, the economic costs of regulating industrial emissions of both greenhouse gases and air pollutants were estimated not to exceed 0.5% of GDP in any given year up to 2020. At the same time, the environmental and health benefits were estimated to exceed $6 billion per year in 2015.

3. Consultations

Following the release of the framework in April, 2007, the government consulted extensively with provinces and territories, as well as with non-governmental organizations, Aboriginal peoples, industry, and other stakeholders, on key policy and regulatory development issues in the framework that remained to be elaborated.

The federal, provincial, and territorial governments have initiated a cooperative process to work through the regulatory issues, through the Environmental Protection and Planning Committee of the Canadian Council of Ministers of the Environment. Some provinces have indicated an interest in negotiating equivalency agreements with the federal government.

The consultations focused on the following issues.

Coverage

- Whether small facilities should be excluded from the regulations in order to minimize administrative burden, and, if so, on what basis?

Targets

- How the greenhouse gas target should be applied in different sectors?
- Whether certain sectors face special circumstances that would require a different application of the framework?
- Finalization of the definition of fixed process emissions in each sector.
- How to treat major expansions and transformations?
- How to incorporate a cleaner fuel standard in the target for new facilities in each sector?
- How the regulations could provide an appropriate incentive for co-generation?

Technology Fund

- Structure of the fund.
- Eligibility of pre-certified investments in specific projects.
- Emission reductions resulting from fund investments.
- Ownership of emission reductions that result from fund investments.

Offset System

- Program start date.
- Criteria for project assessment.
- Types of eligible emission reduction projects.

Clean Development Mechanism

- Types of Clean Development Mechanism credits that would be eligible for compliance with the domestic regulations.

One-time credit for early action

- Process and criteria for allocating the 15 Mt credit for early action.
- Method for implementing the 5 Mt yearly limit.
- Choice of governance structure.

The government has received extensive feedback on the April 2007 regulatory framework.

Provinces and territories have raised concerns about possible duplication with provincial or territorial regulatory regimes and about equity among sectors and regions.

Overall, industry has indicated it will have difficulty in meeting the targets through in-house reductions alone. Some sectors have argued that the targets are too stringent and that the continuous improvement requirement is onerous. Other sectors feel the targets are manageable if there is adequate access to the various compliance mechanisms.

4. Final Industrial Greenhouse Gas Framework: Targets

The April 2007 regulatory framework set out a series of policy decisions regarding the design of the framework. The final regulatory framework for industrial greenhouse gas emissions, as described in this section, reflects the results of the extensive consultations with provinces and territories, environmental groups, and industry, detailed in Annex 1, as well as additional in-depth analysis.

In developing the final regulatory framework for industrial greenhouse gas emissions, the government has been guided by principles of environmental protection, economic development, and regulatory efficiency. In assessing policy choices for the framework, the government balanced the impact that various options would have on the emission reductions to be achieved; the competitiveness of Canadian industries and the overall economic cost of the regulations; and the government's ability to design effective and enforceable regulations. Where appropriate, the unique circumstances of some sectors have been taken into account, within the guiding criteria of the framework. This final framework contributes significantly to the commitment in the 2007 Speech from the Throne to a national strategy to reduce Canada's total greenhouse gas emissions by 20% from 2006 levels by 2020 and by 60% to 70% by 2050.

The federal government still intends to work to reach equivalency agreements with any interested provinces that set enforceable provincial emission standards that are at least as stringent as the federal standards.

4.1 Target application

In all sectors, the required reduction from 2006 emission intensity will be 18% by the beginning of 2010, with 2% continuous improvement every year after that, as laid out in the April 2007 framework. There are three approaches that can be used to apply the target: facility-specific; sector-wide; and corporate.

Facility-specific: Each facility within a sector receives an individual target of an 18% reduction from its own 2006 emission intensity.

This approach is applied in sectors where factors beyond the control of a facility operator affect emissions. For example, terrain characteristics, elevation, configuration, and diameter of pipe all have an impact on emissions from natural gas pipeline facilities, yet these are features that cannot be altered by existing pipeline facilities. Facility-specific targets are also used in sectors with complex and diverse facility structures.

Facility-specific targets will be applied in the following sectors: iron ore pelletizing, potash, base metal smelting, chemicals, fertilizers, iron and steel, ilmenite (titanium), oil sands, petroleum refining, natural gas pipelines, and upstream oil and gas.

Sector-wide: All facilities within a sector face the same target, which is an 18% reduction from the sector's average 2006 emission intensity.

This approach is used in sectors where facility structures are more homogeneous in structure across the whole sector and less complex. It will be applied in the lime, pulp and paper, aluminum and alumina, and cement sectors.

Corporate-specific: Each company within a sector receives a target of an 18% reduction from the average 2006 emission intensity of its entire fleet of facilities.

This approach will be used in the electricity sector, as it provides a strong incentive for investment in new non- and low-emitting power generation since the entire fleet of facilities will include all types of electricity generation. With this approach, electricity companies can reduce their emission intensity by replacing high-emission intensity facilities (for example, coal and other fossil fuels) with non-emitting or lower-emission intensity facilities (for example, wind and other renewable energy, hydro, nuclear).

4.2 Minimum thresholds

Some sectors have a large number of facilities, often including many small facilities that contribute little to the sector's overall emissions. Other sectors have only a few, but large, facilities. It may make sense to exclude very small facilities from coverage by the regulations. The approach taken balances threshold levels to ensure: (1) that the loss in emission reductions will be minimized; (2) that the regulatory burden on both industry and government will be minimized; (3) that similar facilities within a sector will face similar regulatory treatment; and (4) that facilities with similar levels of emissions in different sectors will face similar regulatory treatment. Minimum thresholds will be established for facilities in the chemical, nitrogen-based fertilizer, natural gas pipeline, upstream oil and gas, and electricity sectors.

The thresholds shown in Table 1 will apply in the regulations.

Table 1. Minimum thresholds

SECTOR	THRESHOLD
Chemicals	50 kt CO_2e
Fertilizers (nitrogen-based)	50 kt CO_2e
Natural gas pipelines	50 kt CO_2e
Upstream oil and gas	3 kt/facility and 10,000 barrels of oil equivalent/day/company
Electricity	10 MW

The upstream oil and gas sector comprises a very large number of facilities with a wide variety in size. The proposed threshold is much more stringent than what is currently used by the Government of Alberta in its July 2007 regulations[3] for emissions from this sector. The government is committed to achieving a common threshold and common reporting regime in Alberta. It will continue discussion with the Government of Alberta on these issues, seeking a common practical approach to emissions coverage,

---

[3] Specified Gas Emitters Regulation, Alberta Regulation 139/2007, available at http://www.qp.gov.ab.ca/documents/Regs/2007_139.cfm?frm_isbn=9780779728619

including the phasing of thresholds and the identification of additional measures that could be implemented to address emissions in the rest of the sector. The federal government will also engage in discussions with the Governments of Saskatchewan and British Columbia. These discussions will be informed by the additional information to be provided to the government in response to its December 8, 2007, Section 71 Notice.[4]

In all other sectors, all facilities will be covered by the regulations.

4.3 Fixed process emissions

The April 2007 framework stated that fixed process emissions would receive a 0% target in the regulations, and included a general definition of fixed process emissions. After sectoral analysis and consultation with industry, the definition of fixed process emissions has been made more precise. Fixed process emissions are those emissions that are:

[1]
from chemical processes that produce carbon dioxide emissions and are fixed to production; and

[2]
created in a process where:
- a) carbon that is chemically bound in the raw materials is removed from these materials to produce a carbon-free product (that is, less than 1% carbon by mass); or
- b) carbon is used to remove an undesired component from the raw material and where the raw material is not substitutable; or
- c) unintentional oxidation of hydrocarbon feedstocks results from the catalytic conversion of these feedstocks into products; or
- d) carbon dioxide entrained in ethane gas feedstock is removed and released to the atmosphere in order to process the feedstock.

Fixed process emissions do not include the result of:
- combustion, where combustion is the exothermic reaction of a fuel with gaseous oxygen; or
- a process that is for the purpose of reducing emissions of air pollutants from the facility; or
- the release of formation carbon dioxide from the processing of crude oil or natural gas.

4.4 Definition of "new facility"

In the April 2007 framework, new facilities were defined as those whose first year of operation was 2004 or later, but the framework did not specify how major expansions or transformations of existing plants would be treated.

New facilities will include facilities that came into operation in 2004 or later and include greenfield facilities, major expansions and major transformations.

- Greenfield facilities are those built where no facility existed before.
- Major expansions are defined as a 25% increase in the physical capacity of an existing facility[5].
- Major transformations are those in which there have been significant changes to process.

---

[4] Canada Gazette, Part I, Supplement, Vol. 141, no. 49, December 8, 2007, available at canadagazette.gc.ca/partI/2007/20071208/pdf/g1-14149.pdf.

[5] Other jurisdictions tend to use either a physical capacity or value of investment relative to the value of existing capital stock as a measure.

Only the expanded or transformed portion of the facility would be treated as new, unless the integrated nature of the facility requires that the entire facility be treated as new. Re-opened facilities would be treated as existing facilities, unless they met one or more of the above conditions.

4.5 Application of a cleaner fuel standard

A sector-specific approach will be used to specify a cleaner fuel standard for the determination of targets for new facilities. In sectors where fuel choice is an important factor in a facility's emission intensity, an explicit cleaner fuel standard is needed to ensure that the emission intensity of the sector continues to decrease over time.

This approach will apply to the potash, natural gas pipeline, upstream oil and gas, oil sands, and electricity sectors. A fuel-specific cleaner fuel standard will apply to the electricity sector which will be equivalent to the emission-intensity performance of: “supercritical” technology for coal-fired generation; “natural gas combined cycle” technology for gas-fired generation; and "oil-fired gas turbine" technology for oil-fired generation.

In the other sectors, the cleaner fuel standard will be based on natural gas. In the case of oil sands, the cleaner fuel standard will be process-specific, with a specific natural gas-based cleaner fuel standard for each of mining, in situ, and upgrading.

In those sectors in which carbon capture and storage is a viable option for reducing emissions, for new facilities that do not meet the cleaner fuel standard but that are built capture-ready, the standard would not apply until 2018. This would mean that the 2% annual continuous improvement target would apply to the facility's actual emission intensity. This incentive for carbon capture and storage will apply to the oil sands, electricity, petroleum refining, chemical, and fertilizer sectors.

In other sectors, fuel choice is a less important driver of emission intensity, and the target approach for existing facilities provides an adequate incentive for new facilities to choose cleaner fuels. There is, therefore, no need for an explicit cleaner fuel standard.

For the iron ore pelletizing, lime, iron and steel, titanium, pulp and paper, aluminum and alumina, and cement sectors, a sector-average approach will be taken. For these sectors, a new facility's target in its fourth year of operation would be calculated as the target for that year for existing facilities; that is, an 18% reduction from the sector's average emission intensity in 2006, multiplied by the relevant continuous improvement factors. For the base metal smelting sector, a facility-specific approach will be taken, such that a new base metal smelter's target in its fourth year of operation would be calculated as a 2% reduction from the facility's third year emission intensity.

In all cases, a three-year commissioning period applies, during which the new facility will not face an emission reduction target but will have to report its emissions. This is done in order to allow a new facility time to reach normal operating conditions, so that its target is not based on an artificial baseline (which could have meant that it had fewer reductions to undertake).

4.6 Carbon capture and storage

Carbon capture and storage is a process where carbon dioxide is separated from a facility's process or exhaust gas emissions before they are emitted, transferred from the facility to a suitable storage location, and injected into underground geological formations and monitored to ensure they do not escape into the atmosphere. The stream of carbon dioxide is also sometimes injected into older oil wells to help extract further reserves of oil.

Carbon capture and storage has the potential to store significant amounts of carbon dioxide in Canada. The recently-released report by the ecoENERGY Carbon Capture and Storage Task Force estimates that the Canada-wide potential "could be as high as one-third to one-half" of Canada's projected greenhouse gas emissions in 2050.[6] Estimates by Environment Canada and work undertaken for the Government of Alberta suggest there is a potential to capture and store 50 to 55 Mt of carbon dioxide annually by 2020.

It is a technology that is most cost-effective when it involves large volumes of carbon dioxide, such as those produced at oil sands and electricity generation facilities, and when it is built into new facilities, although it can also be applied to existing facilities. The government therefore intends to develop targets based on carbon capture and storage for upgrader and in-situ facilities in the oil sands sector, and for new coal-fired electricity-generating facilities, that begin operation in 2012 or later. The targets will apply in 2018. The exact specification of these targets will be determined during the development of the proposed regulations. Emissions of a regulated facility that are captured and stored will be considered as emission reductions. Application of these targets is expected to generate an additional 30 Mt in reductions in 2020 beyond those expected from the basic regulatory framework.

Table 2. Target structure by sector and type of facility

	TOUGH	**TOUGHER**	**TOUGHEST**
Sector	**Existing facilities 18%/ 2% from 2010**	**New facilities** **On stream 2004 or later** **3-year commissioning period** **2% continuous improvement**	**Additional requirements for new facilities** **On stream 2012 or later**
Oil sands	As above	Process- specific cleaner fuel standards for mining, in-situ, and upgrading • based on natural gas • incentive for carbon capture and storage until 2018	Target based on carbon capture and storage for in-situ and upgrading • effective 2018
Electricity	As above	Fuel-specific cleaner fuel standards for • coal, gas, and oil • incentive for carbon capture and storage until 2018	Target based on carbon capture and storage for coal • effective 2018
Petroleum refining, chemicals and fertilizers	As above	Process-specific cleaner fuel standards • based on natural gas • incentive for carbon capture and storage until 2018	
Upstream oil and gas, Natural gas pipelines, Potash	As above	Process-specific cleaner fuel standards • based on natural gas	
Iron ore pelletizing, Lime, Iron and steel, Titanium, Pulp and paper, Aluminum and alumina, Cement, Base metal smelters	As above	Process-specific technology	

---

[6] *Canada's Fossil Energy Future: The Way Forward on Carbon Capture and Storage*, January 9, 2008, p.2 available at http://www.nrcan-rncan.gc.ca/com/resoress/publications/fosfos/fosfos-eng.php

4.7 Clean electricity

Electricity is the largest contributor to industrial greenhouse gas emissions and will continue to be so, even after the regulations come into force. The federal government will establish a clean electricity task force to work with provinces and industry to meet an additional 25 Mt reduction goal from the electricity sector by 2020.

Specific measures could include:

- development of an East-West transmission grid and sub-sea cable on the Atlantic coast;
- development of further major hydroelectric projects, such as Peace River C and Lower Churchill;
- introduction of new nuclear reactors; and
- retirement of fossil-fuel electricity generation facilities at the end of their expected life.

Should it not be possible to move ahead on this in cooperation with the provincial governments and electricity utilities, the federal government will consider other options, including regulations if necessary, to meet this goal.

4.8 Co-generation

The April 2007 framework was silent on the treatment of co-generation. Co-generation is the simultaneous generation of heat (or steam) and electricity from the same fuel source. It can result in reduced overall emissions relative to producing heat and electricity separately. The target approach is designed to provide an incentive for facilities to use high-efficiency co-generation.

To reflect the efficiency gains inherent in co-generation, emission targets for facilities that use co-generation would be based on an adjusted baseline that would equal the emission levels if the electricity and heat were produced separately. The emissions that would be deemed to come from the production of heat would be based on those of a stand-alone conventional boiler operating at 80% efficiency. On the basis of these deemed emissions, existing facilities would face an emission-intensity reduction target of 18% in 2010 on the intensity corresponding to heat production and a 2% annual continual improvement requirement thereafter.

The emissions deemed to be due to the production of electricity would be based on the emission intensity rate of stand-alone natural gas combined cycle electricity generation, or 0.418 t/MWh. There would be no reduction target on intensity corresponding to the production of electricity.

This target structure recognizes efficiency gains from using co-generation and provides a strong incentive for facilities to invest in co-generation by reducing the reductions required from a co-generation facility.

4.9 Further target elaboration

The final target approach for industrial greenhouse gas emissions also reflects the unique circumstances of several sectors, within the overall parameters of the framework.

For the cement sector, an expanded definition of production will be applied in order to provide an incentive for this sector to use waste material from other industries in place of emission-intensive clinker.

In the petroleum refining sector, defining production is a challenge since refineries produce many different types of products. The possibility of using the third-party proprietary Solomon Refinery Activity Index to calculate a facility's greenhouse gas emission intensity will be further explored, with a view to using it, should it be feasible and practical so to do.

An emission intensity target will be set for nitrous oxide emissions from adipic acid production that recognizes the voluntary early action taken by industry before any regulations required it.

Unintentional fugitive methane emissions from sources such as equipment leaks and storage from the upstream oil and gas and oil sands sectors and natural gas transmission, distribution, and storage facilities were not identified as covered sources in the April 2007 framework. Reduction requirements for these sources will be implemented through regulated codes of practices; that is, there will be provisions in the regulations that set out best operating practices and technologies. These reductions would be accounted for outside of the regulated activities. This approach is consistent with proposed requirements covering air pollutant emissions from the same sources at these facilities.

The fertilizer sector faces particular challenges related to dependence on natural gas feedstocks, considerable international trade competition, limited ability to pass on costs, and high potential for relocation outside of Canada. To address these challenges, a two-person task force, consisting of a Member of Parliament and an industry representative, will be set up and mandated to return with options for a target approach for the sector that is consistent with the overall framework.

5. Final Industrial Greenhouse Gas Framework: Compliance Mechanisms

The compliance mechanisms are designed to ensure the environmental integrity of the regulatory system, while providing compliance flexibility for industry, so as to reduce the cost of compliance and minimize the administrative burden.

In addition, the need for sufficient liquidity in the emission trading market was considered in the design of the compliance mechanisms. A flourishing emission trading system will help to keep the overall economic cost of emission reductions down, both for industry and for the economy as a whole.

5.1 Technology fund

The technology fund is a key compliance mechanism. In the initial years of the framework, industry will be able to meet a significant part of its regulatory obligations by contributing to this fund. Firms will be able to obtain credits that can be used towards compliance with their regulatory obligations by contributing to the fund, at the established rate and up to the established limit.

Monies received from contributing firms will then be invested by the fund in qualifying greenhouse gas emission reduction technology projects. The fund is designed to act as an incentive to support the development and deployment of technologies to reduce emissions, both in the near term and in the future.

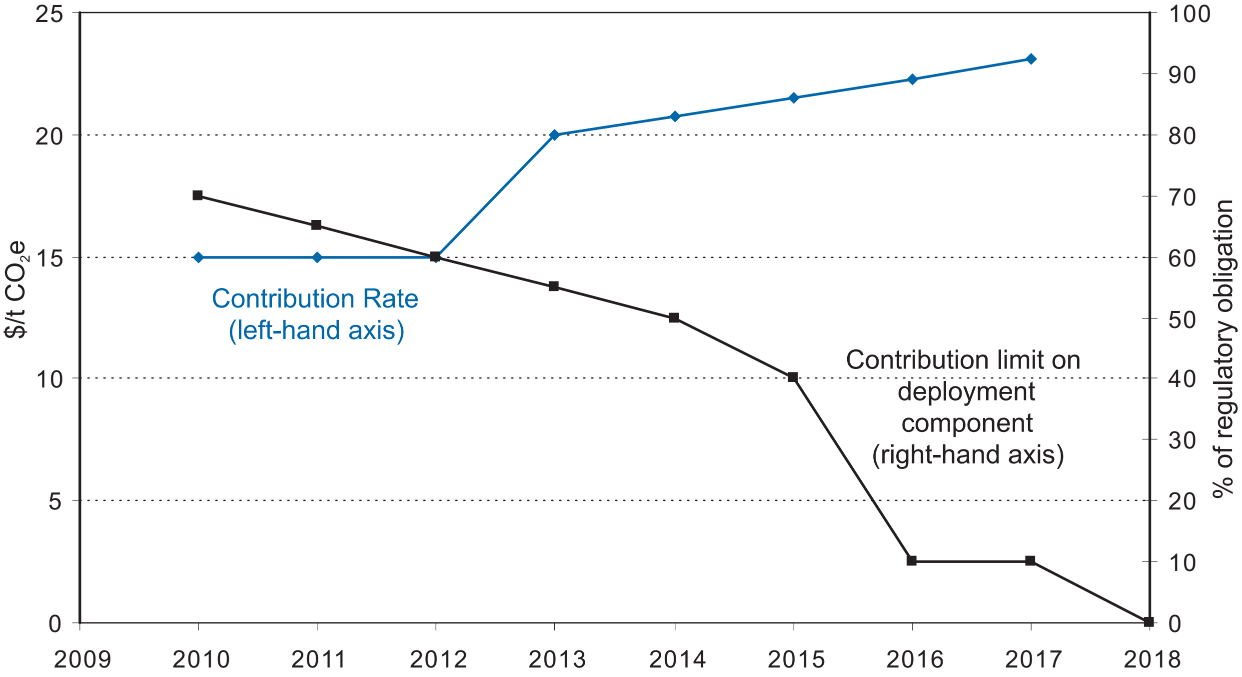
Technological advancement and innovation are critical to achieving significant, long-term reductions in greenhouse gas emissions. New technologies, both under development and ready for deployment, provide a means to transform Canada's industrial production and thereby significantly reduce emissions. Many of these promising technologies face technical, fiscal, or operational barriers to development and deployment, however. The fund would act as an important means of overcoming such barriers and facilitating the diffusion of technologies that reduce emissions of greenhouse gases across industry.

The dual role of the technology fund, as a compliance mechanism and as a technology incentive, informs its design. Moreover, the design of the fund will respect the principle that there be no inter-regional transfer of wealth.

5.1.1 Fund credits: contribution rate, contribution limit, and use

The contribution rate rises over time, while the limit on contributions falls, as detailed in Section 2.1 and Figure 1. This is intended to provide firms with a level of cost certainty in the early years of the regime. As the system matures, this mechanism will gradually be replaced by other emission reduction options, such as internal abatement actions and, importantly, emissions trading in a carbon market.

Figure 1. Technology fund contribution rate in dollars per tonne of carbon dioxide equivalent (CO_2e) and contribution limit on deployment component, 2010-2018.



The contribution limit is the maximum number of credits a firm is eligible to receive for its contributions to the fund in a given year. It is determined as a percentage of each firm's total regulatory obligation (that is, its emission reduction obligation) for all of its facilities in that year, expressed in tonnes of carbon dioxide equivalent; for example, 70% in 2010.

Access to the additional 5 Mt of credits available annually through the research and development component of the fund will be pro rated based on a firm's share of the total regulatory obligation of the regulated industrial sectors. For example, a firm whose regulatory obligation represented 0.1% of the total industrial obligation could contribute to receive up to 5000 tonnes of credits. These credits would be in addition to those available through the fund's deployment and infrastructure component.

5.1.2 Fund design: contributions to and investment by the fund

Firms will be able to contribute to the technology fund and receive credits at the given contribution rate and up to the contribution limit for that year.

The fund will be designed as a portfolio investment fund. That is, in making its investment decisions, the fund will have a mandate to maximize the return on its investment, defined in terms of emission reductions. The portfolio as a whole will be required to demonstrate emission reductions within 10 years. This approach allows a balance between projects with fairly certain, but modest, emission reductions and projects with higher uncertainty.

The majority of investments will be directed towards projects with a high likelihood of yielding greenhouse gas emission reductions in the near term, reflecting contributions to the deployment and infrastructure component of the fund. This component of the technology fund could also help finance projects that would allow technologies that are close to deployment to deliver their full emissions reduction potential.

Projects will cover a broad range of technologies. A portion of investments, particularly from the research and development component of the fund, will be focused on supporting the creation of transformative technologies expected to achieve emission reductions in the medium and longer term.

The portfolio as a whole will be built to reflect these broad considerations. In turn, project selection will be based on a fair and transparent process. For instance, the fund could issue Requests for Proposals specifying criteria on which project proponents could compete.

For projects close to the deployment end of the technology spectrum, the technology fund may claim ownership of the emission reductions from a project until its investment has been recovered, with the number of tonnes required based on the cost of the project.

Rigorous monitoring, verification and reporting requirements will be applied to ensure accountability in the performance of both projects and the fund as a whole.

5.1.3 Pre-certified investments

As an alternative to contributing directly to the technology fund, under the pre-certified investment option, a firm will be eligible to receive credits for investing directly in large-scale and transformative projects, either its own or joint-venture projects, selected by the firm from a menu set out by the federal government.

Pre-certified investments will have the same contribution rate as the technology fund and will be subject to equivalent criteria and requirements, including ownership provisions.

To facilitate the implementation of carbon capture and storage in new facilities in the oil sands and coal-fired electricity sectors, as well as in other sectors that have the potential to make use of such carbon capture and storage projects, the government will start discussions with industry, as well as the Governments of Alberta and Saskatchewan, to pre-certify carbon capture and storage projects. The use of such pre-certified investments will ensure that funds from such sectors as oil and gas will be dedicated to emission reductions from those sectors.

In addition, because of the significant potential for carbon capture and storage to reduce emissions and in order to encourage investment in such projects, contributions of up to 100% of a firm's regulatory obligation in these pre-certified projects will qualify for credits up to 2018. This provision will be limited to firms that can make direct use of carbon-capture-and-storage technology in the following sectors: oil sands, electricity, chemicals, fertilizers, and petroleum refining.

5.1.4 Recognizing other funds

Contributions to other funds that meet all the necessary requirements could potentially be recognized; in particular, contributions to provincial funds. As with the federal fund, a firm contributing to such a fund would be eligible to receive credits, at the contribution rate and up to the contribution limit.

The decision to recognize another fund will be the responsibility of the federal government. To ensure a nationally consistent approach, other funds would be required to fulfill equivalent mandate and criteria as those governing the technology fund.

5.2 Offset System

In addition to providing compliance flexibility for regulated sectors, Canada's domestic offset system is designed to encourage incremental real, verified domestic reductions or removals of greenhouse gas emissions in activities that are not covered by the federal greenhouse gas regulations. In this way, non-regulated sectors can contribute to Canada's national goal of a 20% reduction in greenhouse gas emissions from 2006 levels by 2020.

The offset system will therefore encourage all sectors of the economy to reduce emissions.

More details on the design of the offset system are found in the companion document, *Turning the Corner: Canada's Offset System for Greenhouse Gases.*[7] A general overview of the system is provided below.

The following principles will guide the design of the offset system.

- Offset projects must achieve emission reductions or removals and should provide a net environmental benefit.
- Reductions or removals must occur in Canada.
- The system will promote projects in as many sectors and for as many project types as practical.
- The system must be as simple and cost-effective to administer as possible, and the administrative burden for participants should be minimized.
- The system will build on the experience of Canadian pilot projects and the work of other jurisdictions.

Consideration will be given to recognizing reductions originating in the United States, once the United States has a regulatory system in place and cross-border emissions trading is feasible. A good example of emissions that could be covered by such arrangements would be those stored by the Weyburn-Midale CO_2 Project.

To ensure the environmental integrity of the system, it is essential that the reductions or removals from offset projects are real, incremental, verifiable, and unique.

There are several elements to the incremental criterion:

- reductions or removals must be beyond a baseline;
- reductions or removals must be surplus to all legal requirements, including the regulations under this framework, whether federal, provincial, territorial, or regional;
- reductions or removals must be beyond what is expected from receipt of other climate change incentives from a provincial or territorial government, or the federal government;
- only projects that began to achieve their emission reductions or removals after January 1, 2000, will be eligible; and
- only those emission reductions or removals that take place after January 1, 2008, may generate credits.

Because some types of greenhouse gas reduction or removal projects increase emissions of air pollutants, project proponents may be required to identify and address these negative impacts. The Government of Canada is committed to reducing emissions of both greenhouse gases and air pollutants, and such measures will ensure that all air emissions are reduced.

---

[7] Available at www.ec.gc.ca/default.asp?lang=En&n=75038EBC-1.

Initial design and implementation of the offset system will be undertaken by Environment Canada. This will allow rapid implementation of the program, as well as accountability for results, through direct government oversight. During the first 18 months to two years of operation, the government will bear all initial delivery costs and no initial user fees will be collected.

The private sector will play a substantial role, including developing quantification approaches for project types for approval by the government, implementing projects, verifying real emission reductions or removals under federal oversight, and providing infrastructure and services for the trading of credits.

5.3 Clean Development Mechanism

The April 2007 framework stated that certain credits from the Kyoto Protocol's Clean Development Mechanism could be used for compliance with the domestic regulations, limited to 10% of each firm's regulatory obligation. Strict rules have been established to recognize emission reductions from certain types of projects. All projects are subject to a rigorous verification process by recognized third parties and are reviewed by the Clean Development Mechanism Executive Board to ensure system integrity.

Allowing Clean Development Mechanism credits to be used for compliance will provide additional flexibility in how firms can comply with the regulations and will enhance market liquidity, reducing compliance costs. The limit on the use of these credits for compliance purposes will, however, ensure that the vast majority of emission reductions actually take place in Canada.

There had been some concern that allowing HFC-23 reduction projects to qualify for Clean Development Mechanism credits would create a perverse incentive to increase the production of HCFC-22, an ozone-depleting substance. This issue has largely been addressed by the decision reached under the Montreal Protocol in September 2007 to initiate an accelerated phase-out of HCFCs in developing countries by 2015. In addition, at the December 2007 United Nations Framework Convention on Climate Change meeting in Bali, it was agreed that the Clean Development Mechanism should not lead to increases in HCFC-22 production.

All Clean Development Mechanism project credits will be accepted for compliance with the regulations, with the exception of credits for forest sink projects. Credits from forest sink projects are temporary under Kyoto Protocol rules. This means that they must be replaced periodically. Including credits from forestry projects would have added complexity to the domestic system without significantly reducing compliance costs for regulated industry.

5.4 Credit for early action

Firms in a number of sectors have made efforts over the last decade to reduce emissions. The objective of the credit for early action is to address the possible disadvantage that a regulated facility could face as a result of having undertaken actions to reduce its greenhouse gas emissions before the regulatory regime was established.

The credit for early action will consist of a one-time 15 Mt allocation of bankable, tradable credits in recognition of such reductions achieved by firms that will be subject to the proposed regulations in 2010. These reductions must have been achieved between 1992 and 2006 and be the result of an incremental process change or facility improvement.

More details on the eligibility and program requirements for the credit for early action program are found in the companion document, *Turning the Corner: Canada's Credit for Early Action Program. A general overview of the program*[8] is provided below.

The credit for early action program has been designed using the following principles.

- **Simplicity and cost-effectiveness:** The program will impose the lowest cost possible on government and industry that is consistent with the level of rigour needed.
- **Fairness:** Facilities that wish to have actions considered for recognition will have an equal opportunity and all applications will undergo the same evaluation process.
- **Transparent:** The program rules, technical guidance, and approach to making allocation decisions will be clearly expressed and publicly available to all interested parties.
- **Consistency:** Decisions on issues such as technical guidance and evaluation of submissions will be as consistent as possible across sectors.

5.4.1 Eligibility

An action to reduce greenhouse gas emissions is eligible for early action recognition if it:

- reduced emissions of one or more of the following six greenhouse gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, or sulphur hexafluoride;
- occurred in a facility that meets one of the facility definitions outlined in Schedules 5 to 14 and 16 to 19 of the December 8, 2007 *Notice with respect to reporting information on air pollutants, greenhouse gases and other substances for the 2006 calendar year* and emissions from or the capacity of the facility exceed the minimum threshold specified in Section 4.2 above;[9]
- led to initial reductions in 1992 or later and the reductions continued until at least December 31, 2006; and
- was an "incremental reduction," in the sense of being an emissions reduction resulting from an action beyond the normal business conditions in place at the time the action was taken.

An action to reduce greenhouse gas emissions is not eligible for early action recognition if it was:

- undertaken to meet a legal requirement with a defined date and target;
- the result of a direct federal, provincial or territorial climate change incentive other than an Accelerated Capital Cost Allowance;
- part of a standard improvement in line with changes generally occurring in the industry;
- a result of reductions in production activity or shut-downs; or
- implemented outside the facility's boundary.

---

[8] Available at www.ec.gc.ca/default.asp?lang=En&n=75038EBC-1.

[9] Canada Gazette, Part I, Supplement, Vol. 141, no. 49, December 8, 2007, available at canadagazette.gc.ca/partI/2007/20071208/pdf/g1-14149.pdf

5.4.2 Allocation and issuance of early action credits

Clear eligibility criteria for these credits will be established and communicated to all stakeholders prior to the allocation of the credits. Evidence that eligibility requirements are met must be provided and available for verification and audit.

As stated in the April 2007 framework, if the reductions that meet the eligibility criteria exceed 15 Mt, credits will be allocated on a *pro rata* basis. If the reductions that meet the eligibility criteria are fewer than 15 Mt, a maximum of one credit per tonne of reductions will be allocated. There will be no pre-allocation of credits to any particular sector or region. The 5 Mt limit on credits to be used in any given year will be addressed by issuing 5 Mt of credits in each of the years 2010, 2011, and 2012. Each allocation of credits to any successful applicant will be divided equally over the three years.

Individual firms that took the early action are responsible for preparing their submissions. In order to complete a submission, applicants need to establish their baseline, quantify eligible reductions, and provide evidence to support their claim. Third-party verification of reduction claims will be required. In order to receive their credits, applicants successful in their claim will be required to establish an account in the system that will be used to track the ownership of the various units that may be used for compliance. The intention is to start the application process in spring 2008, with the decision on credit entitlements being made in summer 2009.

6. Transition to Fixed Emission Caps

In the October 2006 *Notice of intent to develop and implement regulations and other measures to reduce air emissions*[10], the government indicated its intention to move from emission-intensity targets to fixed emission caps in the 2020-2025 period. The government still intends this transition to take place.

The anchor for the fixed cap will be the national objective of a 20% absolute reduction in greenhouse gas emissions from 2006 levels by 2020. The level of the cap on industrial emitters will be informed by the results of the application of the emission-intensity system.

As well, any decision in Canada on the transition to a fixed-cap regime for greenhouse gas emissions would take into account developments occurring in other countries, especially the United States, with the aim of establishing a North American emissions trading system once the United States implements a greenhouse gas regulatory system.

---

[10] Available at canadagazette.gc.ca/partI/2006/20061021/pdf/g1-14042.pdf.

7. The Economic Impacts of the Industrial Regulations

This section provides an overview of the likely impact of the regulatory framework for industrial greenhouse gas emissions on economic growth in Canada. This section does not take into account the potential economic impacts of future recommendations of the clean electricity task force.
To conduct this analysis, Environment Canada has used its Energy-Emissions-Economy Model for Canada (E3MC). The model combines the bottom-up, technology-specific Energy 2020 model and the macroeconomic model from Informetrica Limited. This analysis is based on an updated reference case of expected “business-as-usual” growth in Canada's greenhouse gas emissions to 2020 compiled by Environment Canada.

7.1 Impact of the regulatory framework

The analysis conducted by Environment Canada indicates that the regulatory framework for industrial emissions and actions to address fugitive greenhouse gas emissions will result in direct reductions from industry in the range of 145 Mt below reference case levels by 2020. In addition, capital investments arising from the technology fund are expected to generate an additional stream of indirect reductions in the order of 20 Mt per year within this timeframe. The reductions due to technology fund investments are expected to arise in large part as a result of opportunities created both within and outside of the regulated sectors. These opportunities include, for example, access to carbon-capture-and-storage infrastructure by non-regulated industries in Canada's oil-producing regions and the diffusion of energy-efficiency and other technologies from regulated industries across the economy.

In total, the regulatory framework is expected to achieve approximately 165 Mt in direct and indirect emission reductions from the industrial sector by 2020; that is, about a 37% reduction from projected levels or a 21% reduction below 2006 levels. This does not include the additional 25 Mt in targeted reductions from the electricity sector.

7.2 Economic Impacts

Under the authority of the Canadian Environmental Protection Act, 1999, the proposed regulations will require significant reductions in the emissions of greenhouse gases from Canada's most emission-intensive industrial emitters. This implies that Canada's industrial sectors will face an internal cost of emissions, derived from the incremental costs they will face in complying with the regulations. This cost of emissions provides an economic incentive for improved energy efficiency, a switch to cleaner energy sources where possible, and improved management of non-combustion greenhouse gas emissions (such as accidental spills and leaks). In many cases, new technology and other investments will be required.

A portion of the costs associated with these investments and changes in operations will be passed on by the regulated sectors in the form of higher prices, thereby changing the relative price signals to the rest of the economy in favour of low-emitting investment and consumption choices.

Canadians can therefore expect to bear costs under the regulatory framework that are not trivial. At the same time, these costs strike an appropriate balance between environmental results and manageable economic impacts.

For the majority of individual Canadians and for businesses outside the regulated sectors, these costs will be most evident in the form of higher energy prices, particular with respect to electricity and natural gas. However, increased energy conservation and efficiency are expected to limit those increases. The regulatory framework itself is not expected to have a significant impact on motor fuel prices, due to international price competitiveness pressures.

Overall, the analysis indicates that the regulatory framework will have a measurable, negative impact on Canada's real Gross Domestic Product (GDP) level. This impact will begin at relatively marginal levels in the first five years, but gradually increase out to 2020. The assessment indicates that this impact will not exceed 0.5% of forecasted real GDP levels in any given year between 2010 and 2020. Real GDP will thus be modestly affected by the regulatory framework, but will continue to grow at a robust pace.

Some industrial sectors, particularly those that are more carbon-intensive, will be more affected than others, particularly in the short- and medium-term. Costs for these industries are primarily driven by the requirement for accelerated investments in more energy-efficient, less carbon-intensive capital and technologies, with some loss in output possible.

Overall, the regulatory framework results in real, but manageable, economic costs. Most importantly, the regulatory framework will break the link between greenhouse gas emissions from Canada's industrial sector and sustained economic growth for these key industries. It also provides the foundation for Canada to meet its national goal of a 20% reduction in greenhouse gas emissions from 2006 levels by 2020. Full details on the modelling assumptions underlying this economic analysis are available in the technical document "*Turning the Corner: Modelled Analysis of Greenhouse Gas Emission Reductions and Economic Impacts*".

8. Next Steps

The next step is to translate the final regulatory framework for industrial greenhouse gas emissions into regulatory language for the actual regulations. Work has begun on this, and the draft regulations are expected to be published in the *Canada Gazette, Part I* for public comment in fall 2008. The final regulations relating to industrial greenhouse gas emissions are expected to be approved and published in the *Canada Gazette, Part II* in fall 2009, with the greenhouse gas provisions of the regulations coming into force, as planned, on January 1, 2010.

Amendments to the regulations to include the air pollutant elements will be made once the regulatory framework for air pollutants has been finalized in spring 2008. In addition, there will be annual reporting requirements under section 71 of the *Canadian Environmental Protection Act, 1999* until equivalent regulatory requirements are in force.

The emissions reporting requirements will be part of the regulations and will be developed in consultation with provinces/territories, industry, and environmental groups. The data will be managed under the Single Window for Reporting initiative that is now under way at Environment Canada. In addition, procedures for monitoring the ownership and retirement of compliance units will be developed for the purposes of compliance verification.

Consultations undertaken on the greenhouse gas elements of the regulatory framework for air emissions

General consultations

On April 30, May 1 and May 2, 2007, Environment Canada officials held three technical briefings on the overall regulatory framework for representatives from province and territories, industry, and environmental and health non-governmental organizations. These consultations were aimed at validating sector-specific air pollutant targets, including their date of coming into force; finalizing the greenhouse gas regulatory framework; and addressing the scope of the offset system and governance of the technology fund.

Two multi-stakeholder consultation sessions specifically focusing on the compliance mechanisms were held in Montreal on May 31 and June 1, 2007 and in Vancouver on June 4 and 5, 2007.

On December 3, 2007, a high-level multistakeholder group of industry and non-governmental representatives met with Environment Canada officials to discuss the finalization of the framework.

In addition, further in-depth consultations were held, as described below, for the purposes of validating sector-specific air pollutant targets, including their date of coming into force; finalizing the greenhouse gas regulatory framework; and addressing the scope of the offset system and governance of the technology fund.

Provincial/territorial consultations

In-depth consultations on the overall regulatory framework were held with provincial and territorial representatives on May 22-24, 2007, in Gatineau, Quebec. In addition, a number of bilateral discussions at the official and ministerial level have taken place with provincial and territorial counterparts.

On an ongoing basis, the federal government and provincial and territorial governments agreed that the Environmental Protection and Planning Committee of the Canadian Council of Ministers of the Environment would serve as the main federal-provincial/territorial forum in which to discuss the regulatory framework.

The Environmental Protection and Planning Committee has met four times to discuss the framework, and has had two conference calls. In addition, working groups were set up to provide provincial and territorial input into the elements of the regulatory framework.

The Canadian Environmental Protection Act National Advisory Committee was briefed on the regulatory framework twice, once in June and once in December 2007.

Industry consultations

Environment Canada officials met several times with companies and associations in their respective industry sectors. Overall, around 120 meetings were held with industry on the greenhouse gas and other elements of the regulatory framework between May and November 2007.[11]

Aboriginal consultations

At the end of November and early December 2007, a series of three meetings on the regulatory framework were held with three Aboriginal groups: the Assembly of First Nations, the Congress of Aboriginal Peoples, and Inuit Tapiriit Kanatami.

Non-governmental organization consultations

Consultations with environmental and health non-governmental organizations on the regulatory framework were held June 6-8, 2007 and again on December 11 and 12, 2007, both in Ottawa.

Ministerial consultations

During May, June, September, and October 2007, ministers met with chief executive officers and other senior-level executives from the key sectors that will be regulated to discuss the proposed regulatory framework and to listen to industry's views on the framework.

---

[11] The meetings in May to August also included the validation of the air pollutant targets that were in the April 2007 Regulatory Framework for Air Emissions.

App D

THE RESPONSE OF AQUATIC ECOSYSTEMS IN ALBERTA TO ACIDIFYING DEPOSITION

D.W. Schindler
Department of Biological Sciences
University of Alberta
CW 405 Biological Sciences Building
Edmonton, Alberta
T6G 2E9

Introduction

The purpose of this report is to review, summarize and evaluate the most recent advances in critical loadings (effects) research as they apply to developing critical loading criteria for aquatic ecosystems in the province of Alberta.

In order to test the effectiveness of past interim critical loading guidelines, I have also examined chemical data bases for acid-sensitive lakes and streams in areas of Alberta that have received the highest inputs of acidifying substances in the past, for evidence of acidification, using a variety of chemical criteria.

Finally, a number of suggestions are made to improve the collection of future data so that future reviews can be based on the most sensitive possible criteria.

1. The Acidity of Deposition and Acidification of Freshwaters

It was once thought that the pH of unpolluted precipitation would be near 5.6, that of distilled water in equilibrium with atmospheric CO_2, ie. a weak solution of carbonic acid. Investigations in pristine areas have shown that this assumption is incorrect, for even in pristine areas, sulfur and nitrogen emissions from ecosystems are oxidized in the atmosphere to form small amounts of strong acids, while windblown dust and other contaminants supplies small amounts of base cations. In areas remote from anthropogenic sources of strong acids or windblown calcareous soils, precipitation generally has a pH of 5.1-5.4, whereas near arid areas with calcareous dust, higher values are not uncommon (Galloway and Rodhe 1991).

In eastern North America and in Norway, lake and stream acidification has been observed in areas which are both geologically poorly buffered, such as the Precambrian Shield, and where the average pH of precipitation is less than 4.6 (Wright and Henriksen 1978; Schindler et al. 1981; Wright 1983). Where deposition is less acidic, or where geological settings provide sufficient acid neutralizing capacity, acidification has generally not occurred, with the exception of spring acid pulses, as discussed below.

1a. The Acidity of Deposition in Alberta

Precipitation chemistry is measured at 12 sites in Alberta (Figure 1). Details of collection and analytical procedures are given in Myrick (1995), although methods reportedly used for base cation and acidity analyses appear to be erroneous and should be checked.

At present, no sites in Alberta report annual average precipitation as acidic as that reported in eastern North America, although the average pH 4.7 observed at Fort McMurray is very close to the value where effects are expected in sensitive ecosystems (Table 1). Average wet deposition at most sites averages pH 5.0-5.3. Individual precipitation samples with pH values as low as 4.16 have been observed at Fort McMurray (Myrick 1995). These are unlikely to have caused episodic acidification events in streams or lakes, with the exception of the period of spring snowmelt, discussed later. Similar low-pH precipitation events in eastern North America can have pH values as low as 3.0. In Europe, events with pH values as low as 2.3 have been observed (R. F. Wright, pers. comm.).

However, some have questioned the past pH values reported from precipitation near Fort McMurray, due to the proximity of precipitation collectors to dusty roads. They present evidence that both calcium concentrations and pH values in precipitation from a collector near Ft. McMurray decreased markedly during the summer of 1988, when the collector was moved to a location farther from (but still quite near) roads (Bronaugh 1993). A thorough examination of precipitation collection sites and chemical protocols in the province is needed. With the few collection sites in the province, great care must be taken to ensure that sites are representative of large regions, rather than nearby sources.

1b. Deposition of Sulfur and Other Acidifying and Neutralizing Chemicals

In eastern North America, sulfur deposition in the most polluted areas ranges from 20-40 kg SO_4 ha^{-1} yr^{-1} (wet deposition). While this is accompanied by dry deposition of sulfates and SO_2, the measurement of these is so difficult that wet deposition of sulfate has been used as an index of acidifying deposition. Most of the sulfate is balanced either by hydrogen ion, or by ammonium, which has an acidifying effect when taken up or nitrified in ecosystems.

In Europe, several studies have shown that throughfall of sulfur measured in forest canopies is equal to total sulfur deposition, leading to the use of throughfall measurements to estimate regional sulfur deposition (Lovblad et al. 1992). In general, total sulfur deposition was 3 to 4 times sulfur in rain and snow, with higher values reported from near large source areas. Similar conclusions were reached by Lindberg (1992) from studies in the USA. Throughfall measurements are not commonly made in Canada. Moreover, differences in deposition among forest types can be considerable, and the technique is difficult to apply in grasslands. For arid areas like Alberta, where dry deposition is likely to be a high proportion of total deposition, such studies are extremely important.

The only detailed study of throughfall at 15 forested sites was done in the oil sands area in June-Sept. of 1976 (Nyborg et al. 1985). Methods were comparable to those used in European and American studies. Bronaugh (1993) compared Nyborg et al's results with deposition predicted by the Lagrangian ADEPT and ADEPT2 models used to project deposition scenarios for the proposed OSLO development (Concord Scientific 1992), and with wetfall data collected near the oilsands area. He concluded that wetfall in the Ft. McMurray area was about 6 kg SO_4 ha^{-1} yr^{-1}. By assuming that 75% of annual deposition would fall in the four months of Nyborg's study, he calculated that average total sulfate deposition in the area could be as high as 22 kg ha^{-1} yr^{-1}, due to high rates of dry deposition. These results indicate that the effective acidity of deposition in the area could be as high as 0.18 to 0.47 kmol H^+ ha^{-1} yr^{-1}, with highest estimates resulting from throughfall measurements and lowest values from the ADEPT2 model. In Europe, throughfall measurements are used to calibrate and verify total deposition models for sulfate. It appears that such a study is in order in the oil sands area, given the large changes in emissions since Nyborg et al's study twenty years ago, and the fact that his study included only summer months. Until such a study is done, the total deposition of sulfur in the oil sands area will remain a contentious issue. In particular, modelled estimates are likely to be questionable for specific acid-senisitive sites, due to the steep gradient in deposition that appears to be present around Ft. McMurray.

There has been recent recognition that the base cation content of precipitation is important to its effect on acidification of freshwater. For example, declining base cations in eastern US precipitation have almost perfectly balanced decreased emissions of sulfate, leaving little net change in the acidity of precipitation (Hedin et al. 1987; Driscoll and van Dreason 1993). As a result, the slight reduction (20%) in sulfur emissions in the eastem USA has had little effect on the acidity of freshwaters in the region. The declines in base cations are believed to be caused by declining base cation concentrations in acidifying soils. Better management of soil erosion, increased reforestation and urbanization could also contribute to reduced base cation deposition. In brief, the effects of acid precipitation are exacerbated by delays in controlling emissions and other land management practices, so that greater reductions in emissions will be required to achieve any given level of ecosystem recovery.

The changing deposition of base cations, heterogeneous geology, the changing nature of emissions, and changing land-use practices have led European countries and the eastern USA to adopt more complex indices of acidifying deposition. In particular, the widespread saturation of European ecosystems with nitrogen has made it necessary to correct nitrogen inputs for nitrate lost via runoff (Henriksen and Brakke 1990). In order to do this, approaches similar, but not identical to the Acidifying Potential (AP) or net acidifying potential (NAP) formulas of Brydges and Summers (1989) have been adopted, with the latter formulation preferred when nitrate losses from catchments are important (Nilsson and Grennfelt 1988; R. Wright and A. Henriksen, pers. comm. January, 1996). These formulations are consistent with past analyses of acidifying deposition in Alberta and western Canada (Alberta Environment 1990).

1c. The Spatial Distribution of Sulfur and Nitrogen Deposition in Alberta

Because of the few monitoring stations in the province, it has not been possible to map the spatial deposition patterns of acidifying precipitation directly from measured values. Instead, modelling combined with known sulfur sources has been used. Physical and chemical conversion factors used in the modelling have been assumed to be equal to those in other, generally warmer and less arid areas, which have less physical relief and less variation in temperature and precipitation than Alberta. While these restrict the reliability of the models, the resulting maps of sulfur deposition are probably reasonable for broad -scale predictions, due to the relatively low number of large sources of acid precursors in the province. However, the results are less certain for ecosystems near large sulfur sources, where both wet deposition measurements and models predict steep gradients in sulfur deposition. Such a case exists near the oil sands area.

Total sulfur deposition in Alberta has been modelled using Lagrangian models by McDonald et al. (1993) for 1985, and Cheng (1994) for 1990. The latter study used sulfur and nitrogen data in precipitation for 1985, but weather data for 1990. The models indicate two areas of much higher than background deposition. The first is in the Fort McMurray area, where maximum predicted values reach 14.8 kg S ha^{-1} yr^{-1} (44 kg SO_4 ha^{-1} yr^{-1}), in a small area. The second is in the south-central part of the province, where models predict that gas and oil field developments, and power plants in the Wabamun area produce values as high as 8 kg S ha^{-1} yr^{-1} (24 kg SO_4 ha^{-1} yr^{-1}). A considerable area of the province is predicted to have over 2 kg S ha^{-1} yr^{-1} (Figure 2). As expected, near emission sources much of the deposition is predicted to occur as dry sulfur, with 11.4 kg S $ha^{-1}yr^{-1}$ (77%) of that falling in the Fort McMurray area falling as dry fallout. In general, these conclusions are consistent with Nyborg et al's (1986) throughfall measurements.

However, the data bases used for these models appear to be outdated. For example, maps do not reflect the realtively large sulfur sources associated with the oil sands upgrader at Redwater, northeast of Edmonton, as modelled by Concord Environmental Corp. (1991). Similarly, the source inventories used for gas fields in west-central Alberta are now over a decade old. Much development has occurred in the area during that period, and source data need upgrading in order to contruct up to date models of deposition.

Both modelled and throughfall measurements are quite high compared to natural background (non-anthropogenic) deposition of sulfur in Alberta, which is calculated to be 0.45-0.60 kg S ha^{-1} yr^{-1} (McDonald et al. 1993). These are consistent with measurements at the CAPMON station at Cree Lake, Sask., which averaged 0.9 kg SO_4 ha^{-1} yr^{-1} for the period 1984-1991 (reported by Bronaugh 1993).
This value is probably slightly contaminated by anthropogenic sulfur. These low values indicate that anthropogenic activities have increased sulfur deposition in various areas of Alberta by from 3 to 25-fold.

Modelled results suggest that total sulfur deposition in Alberta is relatively low in areas containing acid sensitive lakes and streams. Values appear to be about 3-5 kg S (9-15 kg SO_4) ha-^{1} yr-^{1} in the Muskeg Mountains, although this value needs to be verified by measurements, as discussed above. Maximum wet deposition values are predicted to be <3.3 kg S ha-^{1} yr-^{1} throughout the province, or less than half of the 7 kg S (20 kg SO_4) ha^{-1} yr^{-1} that has been observed to cause rapid acidification of lakes in acid-sensitive areas of eastern Canada. They are also less than the 8-16 kg SO_4 ha^{-1} yr^{-1} (wet) that is believed necessary to protect the most acid-sensitive freshwaters (reviewed by Schindler 1988; Couture 1995). However, as mentioned above, high rates of dry deposition in Alberta add considerably to the overall deposition.

In addition, recent studies have shown that a much higher than anticipated proportion of nitrogen can enter ecosystems from dry deposition, supplying up to 70% of atmospheric nitrate and 33% of ammonia (Lovett 1994). At present, there are no reliable measurements of nitrogen deposition in Alberta. Precipitation collectores are not sampled frequently enough to ensure that nitrogen isn not lost to the atmosphere or biotic uptake.

In contrast to precipitation in the east and in Scandinavia, precipitation in southern Alberta contains relatively large amounts of base cations, as the result of arid conditions and widespread calcareous soils. As a result, the strong correlation observed between deposition of sulfate and hydrogen ion that is observed in eastern Canada is not observed in precipitation collections from much of the province (Sandhu and Blower 1986, Bertram et al. 1986). This condition may not apply for northeastern Alberta, pending verification of precipitation protocols, as described above for the Fort McMurray area.

1d. Calculating Critical Loading of Acidifying Substances

For any given ecosystem, the "critical load" beyond which acidification of freshwaters will begin is a function not only of the chemistry of precipitation as discussed above, but also the ability of the catchment in which the ecosystem lies to add base cations or remove strong acid anions, both of which neutralize incoming acids. The ability of catchments to neutralize acid precipitation results from soil mineralogy and thickness, the amount and history of acid precipitation, and synergistic effects of other human activities such as forestry and other land-use activities. The critical load is a measure of the amount of acid deposition that a given ecosystem can tolerate without adverse long-term effects, Three characteristics are particularly important:

1. The ability of the ecosystem to exchange base cations for incoming hydrogen ions. This is generally a property of the weathering rates of geological materials, and the cation exchange capacities of soils and sediments.

2. The ability of the ecosystem to remove incoming nitrogen. In general, less productive ecosystems are able to remove less nitrogen before reaching "saturation" than more productive ones. Also, nitrification of ammonium to nitrate, a strongly acidifying microbial reaction that can occur in soils and lake waters, can affect an ecosystem's ability to tolerate nitrogen in deposition. Rosen et al. (1992) describe three stages of nitrogen saturation, and the concentrations of nitrate in receiving waters that characterize them. The transition from one phase to another generally requires several years. As a result, the development of nitrogen-saturated conditions is easily detected with well-designed monitoring programs.

3. The ability of ecosystems to reduce or remove sulfate. In particular, both wetlands and lake sediments are efficient sites of sulfate reduction and removal (Bayley et al. 1992; Schindler et al. 1986; Kelly et al. 1987). In addition, soils rich in sesquioxides adsorb sulfur, keeping it from reaching receiving waters.

All of these characteristics can change with time: cation exchange capacity can become exhausted, ability of ecosystems to assimilate nitrogen can be exceeded or compromised by damage to the ecosystem from other stressors such as insects, diseases or fire. Changes in the oxidation-reduction potential of soils and sediments, exhaustion of iron supplies or saturation of soils can reduce abilities to remove sulfate. All are affected by seasonal and interannual changes in precipitation and other climatic conditions. Under natural conditions, the interplay of these processes usually generates some net acid neutralizing capacity, protecting lakes to some degree from acidification. It is unusual to find surface waters that are more acidic than precipitation.

Humic waters represent an exception. Organic acids released by decaying wetland plants can decrease the pH values of incoming precipitation. As a result, even in areas where precipitation contains little anthropogenic sulfur and nitrogen, receiving waters can have pH values that are several tenths of a pH unit below precipitiation values. Such waters are recognizable by their brown color. However, inputs of strong acids from anthropogenic sources decrease the pH values of such waters even more (Jones et al. 1986).

As mentioned above, several authors have attempted to better express the acidification potential of precipitation by accounting for base cations as well as strong acid anions. Perhaps the best known of these is Acidification Potential (AP; Brydges & Summers 1989), which accounts for the deposition of base cations.

$AP = SO_4 - (Ca + Mg)$ where all are expressed in meq m^{-2} yr^{-1}.

In Europe, deposition of all ions is corrected for sea salts before calculating AP. This has been assumed to be unnecessary at inland sites in North America, because sea salts provide only a few percent of deposition in arid inland areas.

The original AP formula ignored nitrogen, assuming that both ammonium and nitrate will be removed by ecosystems, therefore causing little net change in hydrogen ion. Subsequently, with nitrogen saturation being observed at many sites in Europe and several in eastern North America, the formulation has been changed to Net Acidification Potential (NAP), where

$$NAP = SO_4 - (Ca + Mg)_{ppt} + NO_{3runoff}$$

(Brydges and Summers 1989). This formulation recognizes that ammonium, which is basic in atmospheric precipitation, is generally taken up by vegetation, bound in soils, or nitrified to nitrate in ecosystems, all processes that yield hydrogen ion. Nitrate is mobile in soils and waters. As nitrogen demands of ecosystems become saturated, nitrate escapes to downstream waters. These formulations were recommended for freshwaters in an earlier summary of critical loading recommendations in Europe (Nilsson and Grennfelt 1988).

More recently, it has been recognized that nitrate accompanied by acid cations (hydrogen ion and aluminum) has effects that are different from when it is accompanied by base cations leached from soils. If nitrate is accompanied by acid cations, receiving freshwaters become acidic, and concentrations of aluminum can reach values toxic to aquatic organisms. In contrast, if nitrate losses are balanced by base cations, acidification of soils, rather than receiving freshwaters, occurs. At many sites, both processes are occurring. Recent examples are given by Grennfelt and Thornelof (1992) and Dise and Wright (1995).

The 1994 Oslo Convention of the United Nations Economic Council for Europe has set the following steps for developing critical loads in Europe (Wright 1996):
1. Indicator organisms in aquatic and terrestrial ecosystems are identified which indicate the onset of damage from acidification.
2. Chemical criteria associated with the onset of damage to the indicator organisms are identified.
3. The level of deposition at which the chemical criteria are met is identified. This is considered to be the critical load.

Effective Acidity (EA) has also been calculated from measured concentrations of chemicals in precipitation, in order to evaluate its potential to acidify ecosystems (Alberta Environment 1990, Peake 1991; Cheng et al. 1995). Theoretically, EA accounts for the hydrogen ion input in precipitation, plus all chemical and biological processes involving deposited ions that either generate or consume hydrogen ion:

$$EA = [H^+] + (\Sigma\, k_{ai})(A_i) - (\Sigma\, k_{bj})(B_j);$$

(Alberta Environment 1990), where k_{ai} and k_{bj} are coefficients representing various processes that generate and consume strong acid anions and base cations, respectively, and A_i and B_j are deposition rates of strong acid anions and base cations.

In previous applications, static coefficients have largely been used for calcium + magnesium and nitrogen fractions. It is likely that the coefficients for any given ecosystem will change over time with increased nitrogen deposition, for long-term studies of nitrogen in Europe and eastern North America have shown recent evidence of approaching nitrogen saturation, causing higher loss rates of nitrate. Dise and Wright (1995) indicate that significant nitrate leaching typically begins when nitrogen deposition reaches 10 kg N ha^{-1} yr^{-1}. The changing deposition of base cations documented for eastern North America suggests that constant coefficients are insufficient. Until estimates of thresholds for leaching and changing cation yields become available, the EA formulation appears to have no clear advantage over the simpler NAP formulation.
As data bases improve, allowing the development of coefficients appropriate for Alberta ecosystems, the EA formulation may prove to be more advantageous. However, it should be noted that both the AP, NAP and EA approaches are all steady-state models with little predictive power except by comparison with critical loads fro other sites. More recently, dynamic models have been developed that account for the pool sizes and regeneration rates of acid-neutralizing substances in ecosystems. The models have been verified by large-scale whole-ecosystem experiments with increased or reduced levels of acid deposition. Such models require much more intensive data bases than are available in Alberta at present.

Regardless of the formulation used, in the long-term it will be advantageous to keep records of changes in the individual chemical components of NAP and/or EA, rather than just the calculated values, for these will respond differentially to changing land-use patterns, climate, industrial activity and other human influences. Again, it is essential that all precipitation collections be made in areas that are free from contamination by road dust and other immediate anthropogenic sources, and that analyses be supported by rigorous quality control/quality assurance programs, to ensure that data are of high quality.

At present, nitrate is very low (a few micrograms per liter) in runoff waters in acid sensitive regions of Alberta. Clearly, the small present inputs of nitrogen are still being effectively removed by plant uptake and other processes in catchments. As a result, calculations based on AP and NAP formulations will be practically identical. One possible exception is the spring melt period in acid-sensitive rivers, which will be discussed below.

Based on the AP formulation, Alberta Environment (1990) proposed critical loadings for Alberta of 0.1-0.3 keq H^+ ha^{-1} yr^{-1} for sensitive regions of Alberta. These are similar to values proposed by the Interim Acid Deposition Critical Loadings Task Group (1990) to protect highly sensitive lakes in western and northern Canada (0.125-0.31 keq H^+ ha^{-1} yr^{-1}), and to limits proposed for acid-sensitive regions of Europe and eastern North America (Table 2). With the possible exception of sensitive regions in the oil sands area as discussed above, present deposition in sensitive regions of Alberta is less than these values, although AP values as high as 0.57 keq ha^{-1} yr^{-1} have been measured in less sensitive locations. Below, I will examine the sufficiency of these guidelines, based on observed changes in acid-sensitive freshwaters of the province.

2. Responses of Alberta Freshwaters to Past Acid Deposition

As mentioned above, freshwaters showing acidification in the 20th century are in areas that are generally both geologically susceptible and subject to high atmospheric deposition of sulfuric and/or nitric acids.

In contrast to eastern Canada and Scandinavia, Alberta contains few areas that are geologically susceptible to acid precipitation. In general, such waters lie in terrain that is underlain by igneous or metamorphic rock, and have tills and soils that are thin and derived from igneous or metamorphic minerals. Under pristine conditions, such waters generally have alkalinities of less than 6 mg L^{-1} (100 ueq L^{-1})as bicarbonate (10 mg L^{-1} as $CaCO_3$). In Alberta, such waters represent only 4.3% of lakes surveyed (49 of 1133 lakes for which survey data are available; Figure 3). Most sensitive waters lie in high-altitude western regions of Jasper National Park near Amethyst Lake, the Precambrian Shield of the northeastern part of the province, and several upland regions in the northern part of the province, including the Muskeg, Caribou, and Birch Mountains, and the Clear Hills and Swan Hills uplands (Figure 4). While deposition in all of these areas is clearly above background, it appears to be well below the proposed NAP guidelines, and below values shown to be necessary to protect acid-sensitive waters in other jurisdictions. Those that receive the highest acidifying deposition are generally in the northeastern sector of the province, near the oil sands development (Figure 5). In addition, northern areas of Saskatchewan, underlain by Precambrian Shield, contain many acid-sensitive waters (Liaw 1982), as will be discussed later. To test whether waters are affected by recent acidifying inputs, it is necessary to examine data for acid-sensitive waters in these areas for declining pH, alkalinity, or changes in other parameters sensitive to acidification.

2a. Data Available

Twenty lakes in the oil sands area were surveyed by Hesslein (1979) of the federal Department of Fisheries and Oceans in autumn of 1976. The survey was to assess the general sensitivity of lakes in the oil sands area to acidification, and no particular attempt was made to select acid-sensitive lakes. Erickson (1987) surveyed 107 lakes in northern Alberta in 1983. Several sensitive lakes (alkalinity <10 mg L^{-1} as $CaCO_3$) were included in the survey. Saffran and Trew (1996) surveyed 109 lakes between 1987 and 1992. Twelve of the 109 lakes were acid-sensitive. These were followed up in subsequent surveys in 1993. A few of the sensitive lakes had also been surveyed earlier, either by Hesslein (1979) or Erickson (1987). These include Namur & McLelland (Hesslein); Legend (Erickson); and Audet (both Hesslein and Erickson). In addition, data for several lakes in the Fort McMurray area were collected by the AOSERP project, in 1972-1978. These include Namur, Upper Gardiner, and Eaglenest lakes. Of these, only Namur Lake is relatively acid sensitive (alkalinity 400-600 ueq L^{-1}). However, coupled with recent data from Alberta Environmental Protection, chemical records for these three lakes span over two decades, so they were examined for evidence of acidification.

The longest and most detailed records for very acid-sensitive lakes are for lakes L4 and L7 in the Muskeg Mountain area east of the oil sands, and Legend Lake in the Birch Mountains. These lakes were sampled from one to five times each year during the ice-free season between 1987 and 1993. Records for these lakes were also examined, to detect any trends in alkalinity or other indices of acidification with time.

2b. Data Quality

Data quality was checked by comparing the sum of total cations with the sum of total anions, ie charge balance. High quality data sets generally have balances that are within a few percent for clearwater lakes, although in brownwater lakes, organic acids generally make up some of the anion component, so that inorganic ions have a net cation excess. Results were very variable, indicating that there were some data quality problems. Ionic balances for Hesslein's data and earlier AOSERP studies were relatively good, usually within 10%. Ratios of cations to anions for sensitive lakes from Erickson's 1983 survey ranged from 0.3 to 1.03. Most often, cations were deficient, which cannot be explained by organic acids. One possible explanation is that cations in sensitive lakes often appeared to be below the limits of detection for the methods used. In brief, this data set appears to be somewhat less relaible than others.

Ionic balances for acid-sensitive lakes from 1987-1993 ranged from 0.78 to 6.60. Most fell within the range 0.89 to 1.50, with cations generally in excess. Values for the three acid-sensitive lakes with long-term data are shown in Figure 6. Organic anions may have contributed an unknown amount to the anionic total, for all three of the acid-sensitive lakes have high color and DOC (dissolved organic carbon).

In summary, one or more chemical analyses in the Erickson data set appear to be erroneous, but ionic balances for L4, L7 and Legend (L25) lakes, and for Namur, Gardiner and Eaglenest Lakes were deemed to be sufficient in other data sets for examination for time-trends in acid-sensitive variables.

2c. Chemical Indicators of Lake Acidification

Alkalinity and pH are the usual indicators of acidification. However, older measurements using colorimetric procedures are not usually reliable, especially in soft waters. Using modern methods for both, alkalinity is more sensitive than pH, for acidification causes a linear decline in alkalinity, whereas pH changes very little until most alkalinity has been consumed (Figure 7):

(1) $HCO_3^- + H^+ = CO_2 + H_2O$

For example, in an experimental acidification study, Schindler (1980) found that 70 % of alkalinity was destroyed before pH values decreased below the range of natural variation.

Low alkalinity or pH per se is not sufficient evidence that a lake has been acidified by anthropogenic emissions. Many lakes in geologically poorly-buffered areas or areas containing extensive ombrotrophic wetlands have very low alkalinities even with only natural levels of sulfur and nitrogen inputs. Typically, such lakes are either in small catchments with thin, non-calcareous tills and soils, or in catchments containing high proportions of wetlands, which supply organic acids to the lakes. The former lakes usually have very clear waters and pH values of 6-6.5, while the latter have brown waters indicative of colored organic acids, and pH values of 4.9 to 5.5, at which alkalinity from inorganic buffering is zero. Both categories of lakes are extremely sensitive to anthropogenic inputs of strong acids, for they have little natural acid neutralization capacity.

Unless areas are geologically atypical or have low pH values caused by organic acids (indicated by high degrees of organic staining), the amount of bicarbonate present is usually more or less equal the amount of divalent base cations (Ca + Mg), ie. the ratio HCO_3/Ca+Mg is more or less equal to 1.0. Surveys in many pristine northern and western areas have confirmed this observation (reviewed by Henriksen 1980; Liaw 1982).

Acidification also causes divalent base cations to increase, as the result of exchange for H+ in catchment soils and lake sediments. As a result, the ratio HCO_3/Ca+Mg (equivalents) is more sensitive to acidification than either measurement alone. In eastern Ontario, areas with wet sulfate deposition >20 kg ha^{-1} yr^{-1} contain many lakes where the ratio has decreased to zero. Even where deposition is 10 kg SO_4 ha^{-1} yr^{-1}, ratios of 0-0.6 are observed (Schindler 1988). The ratio in freshwaters would be expected to decline over time if acid precipitation is having significant effects.

Finally, increasing conductivity is often a crude index of acidification, because of the very high specific conductivity of the hydrogen ion. It is of interest because old data are usually fairly reliable, because of the measurement's simplicity. However, increases in concentrations of other ionic substances also cause conductivity to increase.

There was no statistically-significant trend in pH with time in any of the lakes. Temporal data for alkalinity, calcium, magnesium, sulfate, conductivity and HCO_3/Ca+Mg for L4, L7, Legend, Namur, Gardiner and Eaglenest lakes are shown in Figures 8-13. If outliers are ignored, all lakes show stable or slight increasing trends in Ca, Mg, HCO_3 and the HCO_3/Ca+Mg ratio, and no detectable trends in other variables.

The lack of significant downward trends in HCO_3/ Ca+Mg indicates that the lakes have not become more acidic during the period of chemical record. In fact, there is a slight, but not statistically significant suggestion that the ratio is increasing. Such observations are consistent with the effects of climatic warming observed at other sites, where in-lake alkalinity increases due to higher in situ reduction and removal of sulfate and nitrate (Schindler et al. 1996a). Climatic warming in the region including Alberta is the highest observed for any region in Canada (Environment Canada 1995).

Both lakes L4 and L7 have high color (>100 Pt units), indicating that their relatively low pH, alkalinity and HCO_3/Ca+Mg are the result of organic acid inputs from wetlands.

In general, as colored lakes are acidified by inputs of strong acids, colored organic acids decline, leaving lakes very clear, with low color and low DOC. In fact, this loss of colored organic acids, rather than declining productivity appears to have been responsible for the apparent "oligotrophication" of lakes in Scandinavia, the Adirondacks and eastern Canada (Schindler 1994). Sulfates in the lakes are low, and nitrates are scarcely detectable.

Similar conclusions have been reached by C. Prather and M. Hickman (pers. comm.) of the University of Alberta for Otasan Lake, in the Birch Mountains, based on paleoecological studies of diatoms. While the lake currently has a pH of 6.7, this value appears to have been stable for over 2000 years. Detailed studies of the lake's catchment indicate that the pH declined at that time due to the development of extensive wetlands in the area, which yielded high concentrations of organic acids to the lake.

Given the relatively short duration of records and some problems with ionic balance, additional assurance that lakes are not being acidified by recent emissions could be obtained from paleoecological studies. Such methods have been used successfully to reveal the time-course and cause of acidification (and in some cases recovery) of lakes in eastern North America, Scandinavia and the northern UK, as well as to reveal the relative contributions of strong acids and organic acids, for different diatom communities develop in response to the two types of acidification (Battarbee et al. 1984; Davis et al. 1985; Allott et al. 1992).

In summary, long-term records, current HCO_3 to Ca + Mg ratios and one paleoecological study show no evidence of anthropogenic acidification of lakes in Alberta. Similar conclusions were reached by Liaw (1982) and Lechner and Howard (1987) for acid-sensitive lakes in northern Saskatchewan, including several near the area of enhanced deposition caused by the oil sands development.

2d. Spring Acid Pulses

The lowest pH values and alkalinity concentrations in streams and small lakes usually occur during spring snowmelt in northern areas. Under pristine conditions, this is generally due to dilution of base cations in near-surface layers of lakes and in streams with snow water, which almost always has much lower base cation concentrations than the lakes and streams, for weathering and cation exchange with soils supply much of the base cations in surface waters. When deposition is enhanced by anthropogenic sources of sulfur and nitrogen, sulfuric and nitric acids can be accumulated in the winter snowpack and discharged in a few weeks in spring, causing episodic acidification (Johannessen and Henriksen 1978). The effects can be exacerbated by the differential meltout of chemicals from the snowpack, with early melt typically containing more strong acids (particularly nitrate) than late snowmelt, although early melt generally contains somewhat higher concentrations of all ions. In extreme cases, pH values may decrease by three pH units (1000-fold increase in hydrogen ion) in a few days (Galloway et al. 1982; Schaefer et al. 1990; Johannessen et al. 1980; Couture 1995). Such depressions have been observed even in waters that area relatively well buffered during the rest of the year. Episodic pH declines have been observed to cause seasonal fish kills in the Adirondacks (Baker and Schofield 1980), Scandinavia (Henriksen et al. 1984), and Ontario (Harvey and Whelpdale 1986).

The relative effects of dilution and strong acid inputs is very site dependent. In the Adirondacks, the spring acid pulse in less acid-sensitive lakes is largely caused by dilution of base cations, whereas that in more sensitive systems is largely caused by inputs of strong acids from melting snow. Increased nitric acid is particularly important (Schaefer et al. 1990). However, in eastern Canada, sulfuric acid can play a more important role than nitric acid (Galloway and Dillon 1983; Jeffries and Semkin 1983).

2e. Spring Acid Pulses in Alberta

Some data were available for acid-sensitive rivers in the Muskeg Mountains, an area of relatively high sulfate deposition. These included the Firebag, Muskeg and Steepbank rivers. Water flow, pH, conductivity, and temperature were monitored continuously in April/May of 1989 and 1990, although in 1989 sampling was discontinued before the end of spring melt.

Moderate pH depressions were observed on the Firebag and Steepbank rivers. In 1990, the pH of the Firebag decreased from values of 7.1-7.4 prior to spring melt to < pH 5.9 over a period of 4 days between April 22 and 26 (Figure 14). The latter value is in the range where

1.2-1.5 [illegible]

damage to sensitive organisms from acidification might be expected to begin (Schindler 1988; Okland and Okland 1980). While the period of low pH lasted only a few days, recovery to pre-melt values required nearly one month. During this period, discharge increased over 5-fold, and conductivity decreased to 50% of pre-melt values. While there are no data for individual base cations or strong acid anions in the rivers during the period, the decrease in conductivity indicates that dilution was responsible for a good part of the acidification.

The pH of the Steepbank River decreased from values of 8.0-8.5 to < 6.0 over approximately three days during the same period (Figure 15). During the same period, flows increased 6-fold, and conductivity decreased several fold, again indicating that dilution was important. The pH recovered to above 7.0 within two days, and appeared to stabilize near pH 7.3-7.5 within three weeks. Records for 1989 for the south and north branches of the Steepbank show smaller pH depressions, of 0.4-0.5 units. Lowest values were not below pH 7.

In contrast, the Muskeg River showed no indication of spring melt pH depression, despite a 20-fold increase in flow and a 3-fold decrease in conductance (Figure 16).

Both the Firebag and Steepbank rivers are sizeable, with flows of 25-130 and 5-65 m^{-3} sec^{-1}, respectively. Because such streams are generally better buffered than smaller tributaries and headwater reaches, more extreme acid pulses would occur in smaller tributaries and headwater reaches of these streams, where discharge is 0.5-10 $m^{-3}sec^{-1}$, as has been observed elsewhere. This possibility should be investigated. In addition, the observations available do not indicate the relative roles of base cation dilution in lakes and streams and deposition of strong acids. Further study, including detailed chemical analyses of samples taken frequently during the acid pulse, are necessary to evaluate the role of strong acid deposition in producing the observed episodic acidification.

3. Effects of Acidifying Emissions from Alberta on Saskatchewan Lakes

As mentioned above, Liaw (1982) and Lechner and Howard (1987) investigated the sensitivity and state of acidification of lakes in northern Saskatchewan. While acid-sensitive lakes were very numerous, particularly in the Precambrian Shield, there was no indication of acidification. In particular, there were no pH values below 5.56 reported, and 80% of lakes had pH values of 6.5-7.5. In clearwater lakes, the ratio of alkalinity to Ca+Mg averaged 0.92. There are no published time-trends for the chemistry of acid-sensitive lakes in Saskatchewan, nor have any data been published for acid-sensitive streams.

4. Other Issues

Two issues mentioned above require additional discussion: the role of nitrogen emissions in acidification, and the interactions between climate change, UV exposure resulting for stratospheric ozone depletion, and lake acidification. In addition, based on studies in other jurisdictions, some mention of effects of acidifying emissions on human health, and on visibility are in order.

A decade ago, it was generally believed that all nitrogen deposited would be removed by ecosystems, because nitrogen is a critical nutrient for the growth of vegetation. Because precipitation usually contained more or less equal amounts of cationic and anionic nitrogen, (Ammonium, nitrate) it was believed that uptake by plants would cancel the acidifying effects in ecosystems. Subsequently, a number of studies have shown that this is incorrect. In populous areas of Europe, high deposition and uptake of ammonium from intensive animal culture has had a strong acidifying effect on soils and aquatic systems (Van Breemen et al. 1983; Schuurkes et al. 1987). Also, at several European sites, increasing nitrate concentrations in lakes and streams were regarded as evidence that the removal of nitrogen by vegetation was declining with time, ie ecosystems were becoming nitrogen-saturated (Henriksen and Brakke 1990, Nilsson and Grennfelt 1988). Studies of forest soils showed that incoming ammonium was often nitrified to nitrate rather than taken up by vegetation. This is an extremely acidifying reaction, releasing two equivalents of hydrogen ion for every equivalent of ammonium consumed (Johnson et al. 1991). Waters in eastern North America have recently shown increasing nitrogen, indicating that nitrogen saturation is being approached (Kelly et al. 1990, Stoddard 1994). Saturation is also appearing in areas of the southern Rocky Mountains where nitrogen emissions are large (Baron et al. 1994). Given the high per capita nitrogen releases in Alberta, monitoring of nitrate values in surface waters is needed to detect the onset of nitrogen saturation in the future, which is likely if human populations and high-temperature combustion processes continue to grow. Moreover, as inputs of acidifying nitrogen compounds increase, critical loadings of sulfur may decrease, for they act in concert to acidify both terrestrial and aquatic ecosystems.

Recently, several studies have shown that episodic acidification can be triggered by warmer, drier climate. Sulfur deposited in wetlands and wet soils is reoxidized under warmer, drier conditions, causing acid pulses to be released to streams during subsequent thunderstorms (Bayley et al. 1992; Lazerte 1993). Such processes are believed to have delayed the recovery of some lakes in Ontario following reductions in acidifying emissions (Dillon et al. 1995). In addition, acid pulses can be generated in lakes previously exposed to high sulfur deposition, if water levels are drawn down enough to expose large areas of littoral sediments where sulfur was deposited in the past (Yan et al. in press).

Climate change has also reduced inputs of colored organic acids to lakes from their catchments (Schindler et al. 1996b). This result, in situ photobleaching and photolytic degradation, can supplement the effects of acid releases mentioned above. As a result, waters become much more transparent to UV radiation. The resulting increase in UV exposure of aquatic organisms can be greater than that caused by stratospheric ozone depletion (Schindler et al. 1996c). Alberta contains some of the world's most transparent lakes, particularly in high alpine areas, where altitude has already increased UV exposure to values 50% more than values at sea level. Thus, climate change, acidification and stratospheric ozone depletion resulting from release of chlorofluorcarbons and halocarbons may have cumulative effects on aquatic communities.

Coordinated management of these diverse environmental problems is thus required in the future, in order to protect aquatic ecosystems.

Several recent studies have shown that air polluted with acid sulfates and aerosols, with and without ozone and nitrogen oxides, is highly correlated with respiratory disease, particularly in children (Graham et al.1990). While the topic is well beyond the scope of this report, it appears worth considering in developing target loads.

Visibility in some parts of the USA has been considerably reduced by anthropogenic emissions of sulfur and nitrogen oxides (USEPA 1995). While effects are most pronounced in the East, there has been particular concern for effects in the West, where even small increases in aerosol emissions have been shown to change visibility dramatically. There is particular concern for areas around national parks in the USA (USEPA 1995). Alberta should have similar concerns, due to the presence of national parks noted for their landscapes. However, due to prevailing wind patterns, threats to visibility in the mountain parks from emissions of sulfur and nitrogen oxides are likely to originate in British Columbia or even with automobile traffic and other sources within the parks, rather than from industrial sources in the province. In general, visibility estimates are made by most major airports, and periodic examination would allow long-term trends to be detected.

5. Summary and Recommendations

Deposition Measurements

There is some controversy over currently measured wet deposition, due to the locations of precipitation collectors, and collection and chemical protocols. The small number of precipitation monitoring locations in the province makes it essential that these be placed in order to be representative of fairly large areas. It is essential that precipitation collection sites are as free as possible from local sources of contamination, ie. so that they represent regional precipitation chemistry. Collectors are not sampled frequently enough to allow accurate estimation of nitrate and ammonium inputs. All values should be corrected for cllector efficiencies.

In addition, older measurements of throughfall indicate that models used for predicting total and dry deposition may be providing unreliable estimates of actual deposition. The data bases used for current sulfur deposition models appear to be outdated, for several large known sulfur sources do not appear in model outputs.

Problems with ionic balances indicate that chemical protocols used in the past need to be improved.

RECOMMENDATIONS:

1. A thorough check of precipitation collection sites, collection protocols and analytical procedures should be undertaken to ensure that future data are "state of the art." Protocols should be modified in order to obtain reliable deposition data for nitrate and ammonium.

2. Throughfall measurements should be made in acid-sensitive catchments of the Muskeg Mountains, in order to determine total sulfur deposition. Wetfall should also be measured. Measurements should be used to calibrate predictive models for wet and total sulfur deposition. Similar measurements at other acid senisitive sites near the oil sands should be considered.

3. The inventory of sulfur sources should be updated. Such updating should be done often in the future, in order to accurately reflect changes in oil sands, gas fields and other developments.

Monitoring of Acid-Sensitive Waters

While some lakes in Alberta have relatively low pH, the few data available currently show no detectable signs of long-term, chronic acidification in Alberta freshwaters. Low pH values appear to be related largely to organic acids from wetlands and wet soils in the catchments of lakes and rivers. Episodic spring acid pulses occur during snowmelt in some acid sensitive streams near the oil sands, but data are currently insufficient to distinguish whether the pulses are caused by natural base cation dilution or deposition of strong acids from anthropogenic sources in snowpacks.

The monitoring of acid-sensitive lakes and streams in areas with high sulfur deposition should be continued indefinitely, for as sulfur accumulates in catchments and lake sediments, acid pulses in streams can follow periods of drought (Bayley et al. 1992; Lazerte 1993). In lakes, such pulses can also result from reoxidation of sulfur sequestered in lake sediments during periods of low lake level (Yan et al. in press). These phenomena involving previously-deposited sulfur would be expected to increase with warmer, drier conditions, which cause lower water flows and higher rates of oxidation in drying wetlands and wet soils. In particular, monitoring during spring melt is critical, for under high sulfur deposition, pH values in littoral areas of lakes can decrease by 3 pH units or more, even in lakes that are otherwise well buffered.

Complete chemistry of the Firebag and Steepbank rivers and some of their smaller tributaries during spring melt would help to interpret the relative roles of strong acid anions in the snowpack vs. dilution in producing the observed spring melt depression. In addition, continuous monitoring of pH and conductivity during several spring melts would help to assess the degree to which pH depression might vary from year to year. An assessment of effects on invertebrate fauna would be a useful addition, for at present, there is no information on biological effects of acidification in aquatic systems of the province.

In addition, some information on spring acid pulses in small acid-vulnerable lakes would be useful. This could be accomplished by making chemical measurements analogous to those for streams at the outflows of acid-sensitive lakes.

RECOMMENDATIONS:

4. Regular water quality monitoring should be done in several acid-sensitive waters in areas receiving high sulfur deposition. Minimum sampling should include during spring melt and in mid to late summer. Particular attention should be paid to the influence of humic substances on the acidifity and buffering capacity of freshwaters.

5. As recommended for precipitation chemistry, chemical protocols for water chemistry should be updated, and subjected to stringent quality control procedures, including screening of data by ionic balance, frequent checks of samples of known concentrations, and participation in round-robin analytical tests with well-known laboratories.

6. Several samples should be taken from the Firebank and Steepbank rivers and smaller tributaries, as well as in small lakes, during the spring melt period, in order to assess the relative roles of base cation dilution and inputs of strong acids deposited in snowpacks in causing the observed acid pulses. Samples should reflect conditions during early, mid, and late melt.

Nitrogen Saturation

Continued monitoring of nitrogen deposition and of nitrogen values in natural waters should be done. As population, motor vehicles and high-temperature combustion sources in the province increase, nitrogen saturation may play an important role in acidification, as it has in Europe, and in the eastern and suthwestern USA.

RECOMMENDATION

7. Regular monitoring of inorganic nitrogen in lakes and streams of areas receiving high nitrogen and sulfur deposition should be done. In particular, samples during spring melt and late summer would allow detection of ecosystem saturation and its effect on episodic and chronic acidification.

Paleoecological Assessments

In the absence of long-term data sets for most acid-sensitive lakes, a paleoecological assessment of changes in diatom or chrysophycean communities of acid sensitive lakes in areas of high sulfur deposition could be quite informative. Such methods allow both the assessment of changes in species, and the calculation of the complete pH history of the lake, in order to assess whether lakes have become more acidic due to increased sulfur deposition from human activity.

RECOMMENDATION

8. Paleoecological studies should be undertaken in selected acid-sensitive lakes in high deposition areas, in order to distinguish past acidification resulting from natural processes from that caused by recent increases in sulfur and nitrogen deposition.

Coordinated Monitoring of Terrestrial and Aquatic Ecosystems

Finally, collection of the data necessary to examine critical loads for acid sensitive sites using the most recent European dynamic models should be undertaken. For lakes and streams, this would require annual precipitation at the site, annual discharge measurements, and some seasonal chemistry, in addition to information on soil depth and type, base saturation, cation exchange capacity and bulk density for the catchments in question.

RECOMMENDATION

9. Monitoring sites for acid-sensitive aquatic systems should be integrated with those for sensitive forests and soils, in order to provide a data base suitable for predicitive modelling of acidification under future deposition regimes.

Interim Target Loading

Although they are few in number, there are some extremely acid-sensitive waters in Alberta, including areas where acidifying deposition caused by human activity is several-fold greater than natural background values. Given the paucity of reliable precipitation data with which to calculate true acid loading, it is probably wise to adopt target loads that are equal to or more stringent than current critical loads for the most sensitive waters in Europe. Target and critical loads should be reviewed periodically, as further data resulting from the above recommendations become available. To be successful, critical loading evaluations and agreement on target loading must be based on a flexible, interactive program of monitoring, research and policy assessment.

RECOMMENDATION

10. An interim target load of no higher than 0.25 keq $H^+ha^{-1}yr$-1 should be adopted, in line with that used for the most sensitive regions of Europe. This should be modified as appropriate as the data base for sensitive ecosystems and deposition values improves.

6. Acknowledgements

Karen Saffran and David Trew of Alberta Environmental Protection supplied data and analytical support for this report. Bryan Kemper, R.F. Wright, Karen Saffran, David Trew and Mitch Bronaugh criticized an earlier draft of this manuscript, improving it greatly. Brian Parker and Margaret Foxcroft assisted in formatting figures and text in the final manuscript.

Figure Captions

Figure 1. The locations of stations for monitoring precipitation chemistry in Alberta.

Figure 2. Modelled total sulfur deposition in Alberta, 1990. Contour Intervals are 1 kg S ha^{-1} yr^{-1}. From Cheng (1994).

Figure 3. The alkalinity of surveyed lakes in Alberta. Data from Saffran and Trew (1996).

Figure 4. The locations of surveyed lakes in Alberta. Low alkalinity lakes that are expected to be acid-sensitive are shown in red. From Saffran and Trew (1996).

Figure 5. The locations of acid-sensitive freshwaters in relation to sulfur deposition patterns. Units are as in Figures 2 and 4.

Figure 6. Ratios of total cations to total anions in analyses from L4, L7 and Legend lakes, 1987-1993. The dotted horizontal line represents 1.0, the value expected from perfect ionic balance. Data from Saffran and Trew (1996).

Figure 7. The relationship between acid addition, pH and alkalinity in a typical freshwater. From Henriksen (1980)

Figures 8-13. Time-trends in the ratio of HCO_3, magnesium, alkalinity, calcium, conductivity, and sulfate for L4, L7, Legend, Namur, Gardiner and Eaglenest lakes, respectively. Only summer data are plotted for the latter three lakes in order to ensure long-term compatibility of data. Data from Saffran and Trew (1996).

Figures 14-16. Data for pH, conductivity and water flow from the Firebag, Steepbank and Muskeg rivers in the Muskeg Mountain area during spring melt. Note the pH depression in the former two rivers. from Saffran and Trew (1996).

References

Alberta Environmental Protection. 1990. A review of approaches for setting acidic deposition limits in Alberta. 64 pp.

Allott, T.E.H., R. Harriman and R.W. Battarbee. 1992. Reversibility of lake acidification at the Round Loch of Glenhead, Galloway, Scotland. Environ, Pollut. 77: 219-225.

Baker, J.P. and C. Schofield C. 1980. Aluminum toxicity to fish as related to acid precipitation and Adirondack surface water quality. In: D. Drablos and E. Tollan (eds.). Ecological Impact of Acid Precipitation. NIVA, Oslo, Norway, p. 292-293.

Baron, J.S., D.S. Ojima, E.A. Holland, and W.J. Parton. 1994. Analysis of nitrogen saturation potential in a Rocky Mountain tundra and forest: Implications for aquatic ecosystems. Biogeoch. 27: 61-82

Battarbee, R.W. 1984. Diaton analysis and the acidification of lakes. Phil. Trans. Roy. Soc. Lond. B 305: 451-477.

Bayley, S.E., D.W. Schindler, B.R. Parker, M.P. Stainton and K.G. Beaty. 1992. Effect of forest fire on drought on acidity of a base-poor boreal forest stream: Similarities between climatic warming and acidic precipitation. Biogeochem. 17: 191-204.

Bertram, H.L., N.C. Das and Y.K. Lau. 1986. Precipitation chemistry measureent in ALberta. Water, Air, Soil Pollut. 30: 231-237.

Bronaugh, M. 1993. Evaluation of sulphur deposition rates in the Athabasca Oil Sands area. Submission to the Alberta ERCB, June 1993. 45pp + Appd.

Brydges, T.G. and P.W. Summers. 1989. The acidifying potential of atmospheric deposition in Canada. Water Air Soil Pollut. 43: 249-263.

Cheng, L. 1994. Concentration and deposition of anthropogenic pollutants in Alberta (Summary Report). Alberta Research Council. 10pp.

Cheng, L., R.P. Angle, E. Peake and H.S. Sandhu. 1995. Effective acidity modelling to establish acidic deposition objectives and manage emissions. Atmos. Environ. 29: 383-392.

Concord Environmental Corp. 1991. Draft Environmental Impact Assessment, OSLO Project. Baseline Report Part II. Redwater-Upgrader. Calgary, AB 261pp.

Concord Environmental Corp. 1992. Volume IV. Air quality assessment for the continued improvement and development of the Syncrude Mildred Lake operation. Prepared for Syncrude Canada Ltd. Calgary, AB.

Coote, D.R., D. Siminovitch, S.S. Singh and C. Wang. 1982. The significance of acid rain to agriculture in eastern Canada. Research Branch, Agriculture Canada. LRRI Contribution 119, CBRI Contribution 1236. 26 pp.

Couture, S. 1995. Response of the Laflamme Lake watershed, Quebec, to reduced sulphate deposition. Can. J. Fish. Aquat. Sci. 52: 1936-1943.

Davis, R.B., D.S. Anderson and F. Berge. 1985. Paleolimnological evidence that lake acidification is accompanied by loss of organic matter. Nature 316: 436-438.

Dillon, P.J., L.A. Molot and M. Futter. 1995. The effect of drought on catchment export of sulfate and the recovery of acidified lakes. Int. Jour. Environ. Monito. Audit. (in press).

Dise, N.B., and R.F. Wright. 1995. Nitrogen leaching from European forests in relation to nitrogen deposition. Forest Ecol. Manage. 71: 153-162.

Driscoll, C.T. and R. van Dreason. 1993. Seasonal and long-term patterns in the chemistry of Adirondack lakes. Water Air Soil Pollut. 67: 319-344.

Driscoll, C.T., K.M. Postek, W. Krestser and D.J. Raynal. Long-term trends in the chemistry of precipitation and lake water in the Adirondack region of New York, USA. Water Air Soil Pollut. (in press).

Environment Canada. 1994. Annual report on the federal-provincial agreements for the eastern Canada acid rain program.

Environment Canada. 1995. The state of Canada's climate: Monitoring variability and change. State of the Environment Report 95-1. 52 pp.

Erickson, P.K. 1987. An assessment of the potential sensitivity of Alberta lakes to acidic deposition. Alberta Environment. 137pp.

Freer-Smith, P.H., and J.N. B. Bell. 1995. World health organization air quality guidelines for Europe. Draft chapters on SO_2.

Galloway, J.N. and P.J. Dillon. 1983. Effects of acidic deposition: The importance of nitrogen. pp 145-160 in Ecological Effects of Acid Deposition. SNV PM 1636, National Swedish Environmental Protection Board, Stockholm.

Galloway, J.N., G.R. Hendrey, C. L. Schofield, N.E. Peters and A. H. Johannes. 1987. Processes and causes of lake acidification during spring snowmelt in the west-central Adirondack Mountains, New York. Can J. Fish. Aquat.Sci. 44: 1595-1602.

Galloway, J.N., Likens, G.E., Keene, W.C. and J.M. Miller. 1982. The composition of precipitation in remote areas of the world. J. Geophys. Res. 87: 8771-8786.

Galloway, J.N. and H. Rodhe. 1991. Regional atmospheric budgets of S and N fluxes: how well can they be quantified? In: F.T. Last, F.T. and R. Watling (eds.). Acidic Deposition: Its Nature and Impacts. Proceedings of the Royal Society of Edinburgh, Vol. 97B: 61-80.

Graham, J.A. and 12 others. Direct health effects of air pollutants associated with acid precursor emissions. Report 22, National Acid Precipitation Assessment Program, Washington, D.C.

Grennfelt, P., and E. Thornelof (eds). 1992. Critical loads for nitrogen. A Workshop Report. NORD 1992:41, Nordic Council of Ministers, Copenhagen. 428pp.

Harvey, H.H., and D. M. Whelpdale. 1986. On the prediction of acid precipitation events and their effects on fishes. pp 45-55 in R.E. Johnson (ed). Acid Rain/Fisheries. American Fisheries Society, Bethesda, MD, USA.

Hedin, L.O., G.E. Likens and F.H. Bormann. 1987. Decrease in precipitation acidity resulting from decreased SO_4 concentration. Nature 325: 244-246.

Henriksen, A. 1980. Acidification of freshwaters: A large-scale titration. In: Dr. Drablos and A. Tollan (eds.). Ecological Impact of Acid Precipitation. NIVA, Oslo, Norway pp. 68-74.

Henriksen, A. and D.F. Brakke. 1990. Interim Acid Deposition Critical Loadings Task Force. Interim acid deposition critical loadings for western and northern Canada. 31pp.

Henriksen, A., O.K. Skoghein and B.O. Rossland. 1984. Episodic changes in pH and aluminium-speciation kill fish in a Norwegian salmon river. Vatten 40: 255-260.

Hesslein, R.H. 1979. Lake acidification potential in the Alberta Oil Sands Environmental Research Program Study area. AOSERP Project HY2.2. 34pp.

Interim Acid Deposition Critical Loadings Task Group. 1990. Interim acid deposition critical loadings for western and northern Canada. 31 pp.

Jeffries, D.S., and R.G. Semkin. 1983. Changes in snowpack, stream and lake chemistry during snowmelt in the Turkey Lakes watershed. pp 377-386 in Proceedings, International Conference on Acid Precipitation, Lindau, FRG. VDI-Berichte 500.

Johannessen, M., and A. Henriksen. 1978. Chemistry of snow meltwater: changes in concentration during melting. Water Resour. Res. 14: 615-619.

Johannessen, M., A. Skartveit and R. F. Wright. 1980. Streamwater chemistry before, during and after snowmelt. P 224-225 In: D. Drablos and A. Tollan (eds.). Ecological Impact of Acid Precipitation. SNSF Project, NIVA, Oslo, Norway. 383pp.

Johnson D., M.S. Cresser, S.I. Nilsson, J. Turner, B. Ulrich, D. Binkley and D.w. Cole. 1991. Soil changes in forest ecosystems: evidence for and probably causes. In: F.T. Last and R. Watling (eds.). Acidic Deposition: Its Nature and Impacts. Proceedings of the Royal Society of Edinburgh, Vol. 97B: 81-116.

Jones, M.L., D.R. Marmorek, B.S. Reuber, P.J. McNamee, and L.P. Rattie. 1986. Brown waters: Relative importance of external and internal sources of acidification on catchment biota. ESSA Environmental and Social Systems Analysts, Ltd., Toronto. 85pp.

Kelly, C.A., J.W.M. Rudd and D.W. Schindler. 1990. Lake acidification by nitric acid:... future considerations. Water Air Soil Pollut. 50: 49-61.

Lazerte, B.D. 1993. The impact of drought and acidification on the chemical exports from a minerotrophic conifer swamp. Biogeochem. 18: 153-175.

Lechner, L., and G. Howard. 1987. Sensitivity of Saskatchewan surface waters to acidic inputs. Saskatchewan Environment.

Liaw, W.K. 1982. Chemical sensitivity of northern Saskatchewan waters to acidification. p. 485-510 in Proceedings, Acid Forming Emissions in Alberta and Their Ecological Effects.Alberta Dept. of Environment, Canadian Petroleumssoc., Oil Sands Environmental Study Group. Edmonton, AB. 649pp.

Lindberg, S. 1992. Atmospheric deposition and canopy interactions of sulfur.In Johnson, D. and S. Lindberg. Atmospheric deposition and forest nutrient cycling: a synthesis of the Integrated Forest Study. Springer-Verlag.

Lovblad, G., M. Amann, B. Andersen, M. Hovmand, S. Joffre and U. Pedersen. 1992. Depsoition of sulfur and nitrogen in the Nordic countries: Present and future. Ambio 21: 339-347.

Lovett, G.M. 1994. Atmospheric deposition of nutrients and pollutants in North America: an ecological perspective. Ecol. Appl. 4: 629-650.

McDonald, K., M. Olson and K. Oikawa. 1993. A computed sulfur budget for Alberta. Environment Canada, 23pp + figures.

Molot, L.A., P.J. Dillon and b.d. LaZerte. 1989. Factors affecting alkalinity concentrations of streamwater during snowmelt in Central Ontario. Can. J. Fish. Aquat. Sci. 46: 1658-1666.

Myrick, R.H. 1995. Air quality monitoring report for Alberta 1993. Alberta Environmental Protection.

Nilsson, J., and P. Grennfelt. 1988. Critical Loads for Sulphur and Nitrogen. Miljorapport, ECE, 31pp.

Nyborg, M., R. Parker, S. Takyi and P. Yeung. 1985. Deposition of sulphur and its influence on soils in the AOSERP study area. AOSERP report L-86. Alberta Environment. 153pp.

Okland, J. and K.A. Okland. 1980. pH level and food organisms for fish: Studies of 1,000 lakes in Norway. In: D. Drablos and A. Tollan (eds.). Ecological Impact of Acid Precipitation. NIVA, Oslo, Norway, p. 326-327.

Peake, E. 1991. A comparison of methods for calculating effective acidity (EA) based on Alberta data. Draft report for Management Committee of the Acid Deposition Program. 15 pp.

Posch, M., P.A.M. de Smet, J.-P. Hetteligh abd R.J. Downing (eds) 1995. Calculation and mapping of critical thrresholds in Europe. RIVM Report, National Institute of Public Health and the Environment, Bilthoven, Nehterlands.

Rosen, K., P. Gundersen, L. Tegnhammar, M. Johansson and T. Frogner. 1992. Nitrogen enrichment of nordic forest ecosystems. Ambio 21: 364-368.

Saffran, K.A., and D.O. Drew. 1996. The sensitivity of Alberta lakes to acidifying deposition: An update of sensitivity maps with emphasis on 109 northeastern lakes. Alberta Environmental Protection, Edmonton AB. (in preparation).

Sandhu, H.S., and L. Blower. 1986. Acid-forming emissions in Alberta, Canada. Environmental Mangement 10: 689-695.

Schaefer, D. A., C. T. Driscoll Jr., R. van Dreason and C.P. Yatsko. 1990. The episodic acidification of Adirondack lakes during snowmelt. Water Resour. Res. 26: 1639-1647.

Schindler, D.W. Experimental effects of a whole lake: A test of the oligotrophication hypothesis. In: D. Drablos and E. Tollan (eds.). Ecological Impact of Acid Precipitation. NIVA, Oslo, Noway, p. 370-374.

Schindler, D.W. 1988. Effects of acid rain on freshwater ecosystems. Science (Wash. D.C.) 239: 149-157.

Schindler, D.W. 1994. Changes caused by acidification to the biodiversity: productivity and biogeochemical cycles of lakes. In: C.E.W. Steinberg and R.W. Wright (eds.). Acidification of Freshwater Ecosystems. Implications for the Future. John Wiley and Sons Ltd. p. 153-164.

Schindler, D.W. and twelve others. 1981. Atmosphere-biosphere interactions toward a better understanding of the ecological consequences of fossil fuel combustion. National Academy Press, Washington, DC. National Academy of Science. 263 pp.

Schindler, D.W., S.E. Bayley, B.R. Parker, K.G. Beaty, D.R. Cruikshank, E.J. Fee, E.U. Schindler and M.P. Stainton. 1996a. The effects of climatic warming on the properties of boreal lakes and streams at the Experimental Lakes Area, Northwestern Ontario. Limnol. Oceanogr. (in press)

Schindler, D.W., P.J. Curtis, S.E. Bayley, B.R. Parker, K.G. Beaty and M.P. Stainton. 1996b. Changes induced by climatic warming and acidification in the dissolved organic carbon budgets of boreal lakes. Biogeochemistry (in press).

Schindler, D.W., P.J. Curtis, B. Parker, and M.P. Stainton. 1996c. Consequences of climatic warming and lake acidification for UVb penetration in North American boreal lakes. Nature (in press).

Schuurkes, J.A.A.R., M.A. Elbers, J.J.F. Gudden and J.G.M.Roelefs. 1987. Effects of simulated ammonium sulphate and sulphuric acid rain on acidification, water quality and flora of small-scale soft water systems. Aquat. Bot. 28: 199-226.

Stoddard, J.L. 1994. Long-term changes in watershed retention of nitrogen: its causes and aquatic consequences. Ch. 8 in: L.A. Baker (ed.). Environmental Chemistry of Lakes and Reservoirs. Adv. in Chem. Series no. 237, Amer. Chem. Soc.

USEPA (Environmental Protection Agency). 1995. Acid deposition standard feasibility study report to congress. EPA 430-R-95-001a. 120pp + appendices.

van Breemen, N., N.J. Mulder and C.T. Driscoll. 1983. Acidification and alkalinization of soils. Nature 299: 548-550.

Wright, R.F.1983. Acidification of freshwaters in Europe. Water Qual. Bull. 8: 137-142.

Wright, R.F. 1996. Use of the critical load concept in determining present and future damage to forests and surface waters. Abstract, Symposium on Acidifying Emissions in Alberta. Red Deer, AB. Apr 15-17, 1996.

Wright, R.F., and A. Henriksen. 1978. Chemistry of small Norwegian lakes with special reference to acid precipitation. Limnol. Oceanogr. 23: 487-498.

Yan, N.D., W. Keller, N.M. Scully, D.R.S. Lean and P.J. Dillon. 1996. Increased UV-B penetration in a lake owing to drought-induced acidification. Nature (in press).

Definitions

acidification- generally used for either an increase in hydrogen ion (decrease in pH), or a loss of alkalinity in natural waters.

alkalinity- the inorganic buffering capacity of waters. In most casess, it is equal to bicarbonate minus hydrogen ion, where both are expressed in equivalents. It can assume negative values when bicarbonate is exhausted by acid additions.

anion- a negatively charged ion in solution. In most waters, bicarbonate, plus the three strong acid anions sulfate, nitrate and chloride, make up most of the anions, although in brown waters, organic substances usually supply a net anionic charge in addition.

buffering capacity- the ability of water to resist acidification. For most circumneutral waters, alkalinity will be the major component, although in brown waters, organic acids may also neutralize acids to some degree.

cation- a positively charged ion in solution. Acidic cations include hydrogen ion and some aluminum species. Base cations include calcium, magnesium, sodium, and potassium.

cation exchange- the process by which incoming hydrogen ion replaces base cations in soils, generally leading to losses of base cations to water.

critical load- the maximum input of sulfur or nitrogen that will not cause damage to the most sensitive components of ecosystems.
target load- a load chosen for regulatory purposes. It may be less than the critical load to ensure that ecosystems are fully protected, or higher than the critical load, in which case some ecological damage must be accepted.

dry deposition- the amount of a chemical falling as particles, dust, or being drawn directly from the atmosphere in gaseous form.

ionic balance- the state where the sum of cations equals the sum of anions, in equivalents. Waters are in ionic balance, for they do not have a net electrical charge.

nitrogen saturation- the point at which nitrogen deposition exceeds the demands of biota, so that losses of nitrogen to surface and groundwater begin.

Pt units- a crude measure of dissolved color in lake water, based on the color imparted by standards made from standard solutions of platinum and cobalt. Most clear waters have 5-15 Pt units of color. Many lakes in areas with wetlands can have 50-150 Pt units of color, or even more.

wet deposition- the amount of a chemical substance falling as rain or snow. It varies greatly with altitude, proximity to source, humidity and vegetation or surface characteristics.

fig 1

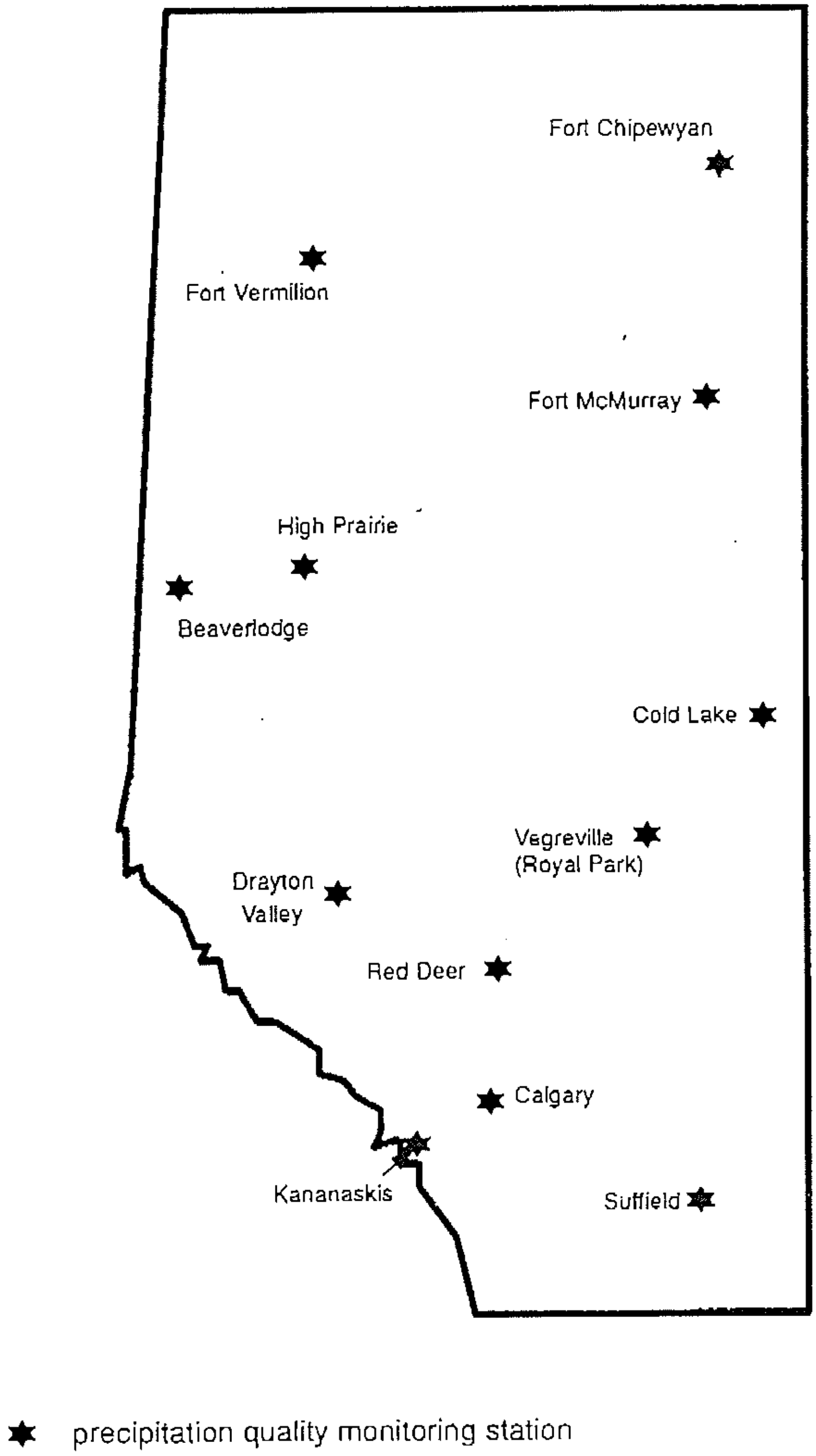


Figure 7-1 Location of precipitation quality monitoring stations.

fig 2

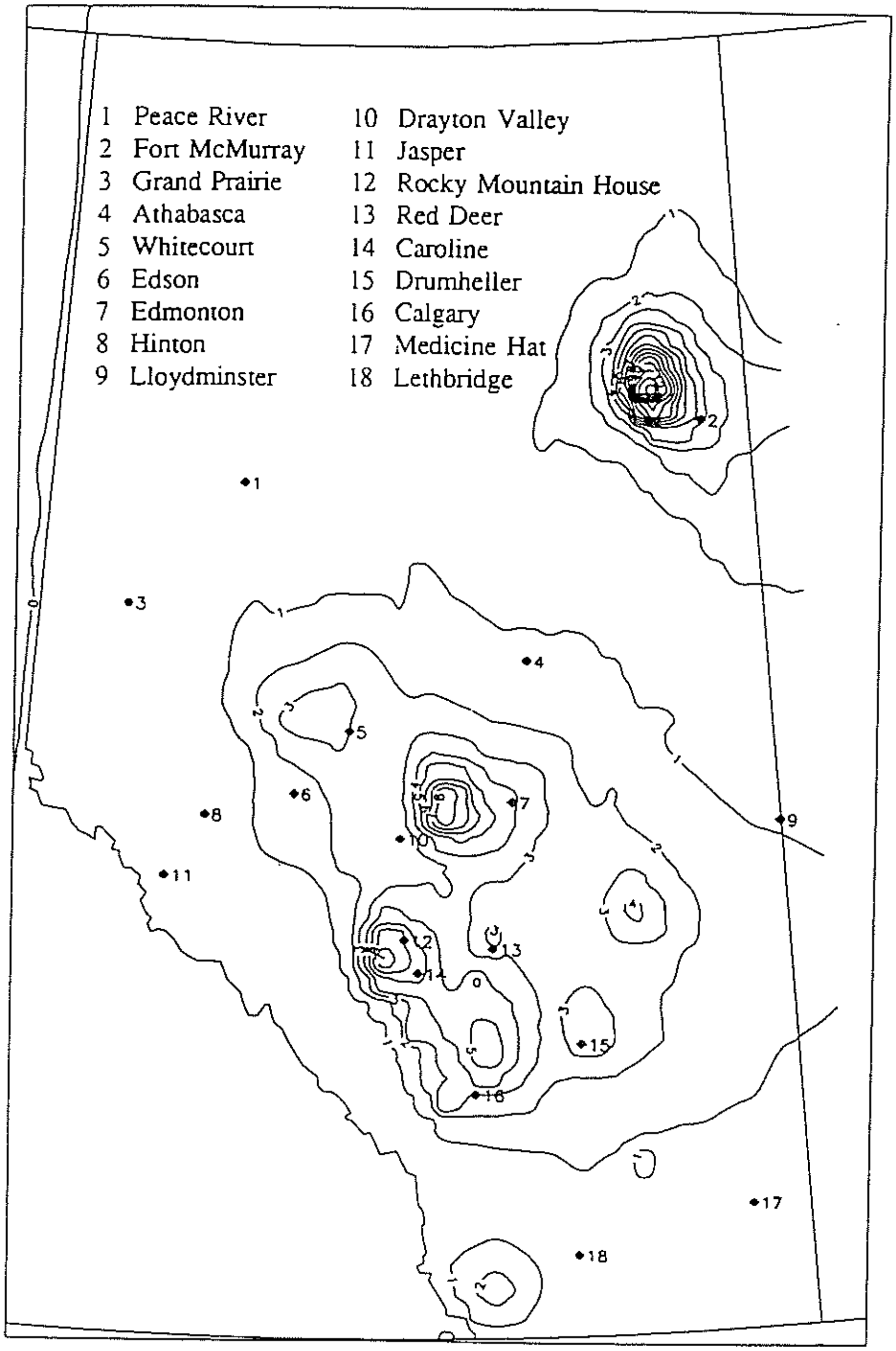


Figure 3. Predicted 1990 annual total deposition of sulphur in Alberta (contour interval in 1 kg ha^{-1} y^{-1} of S).

fig 3

TOTAL ALKALINITIES FOR 109 LAKES IN NORTHERN ALBERTA

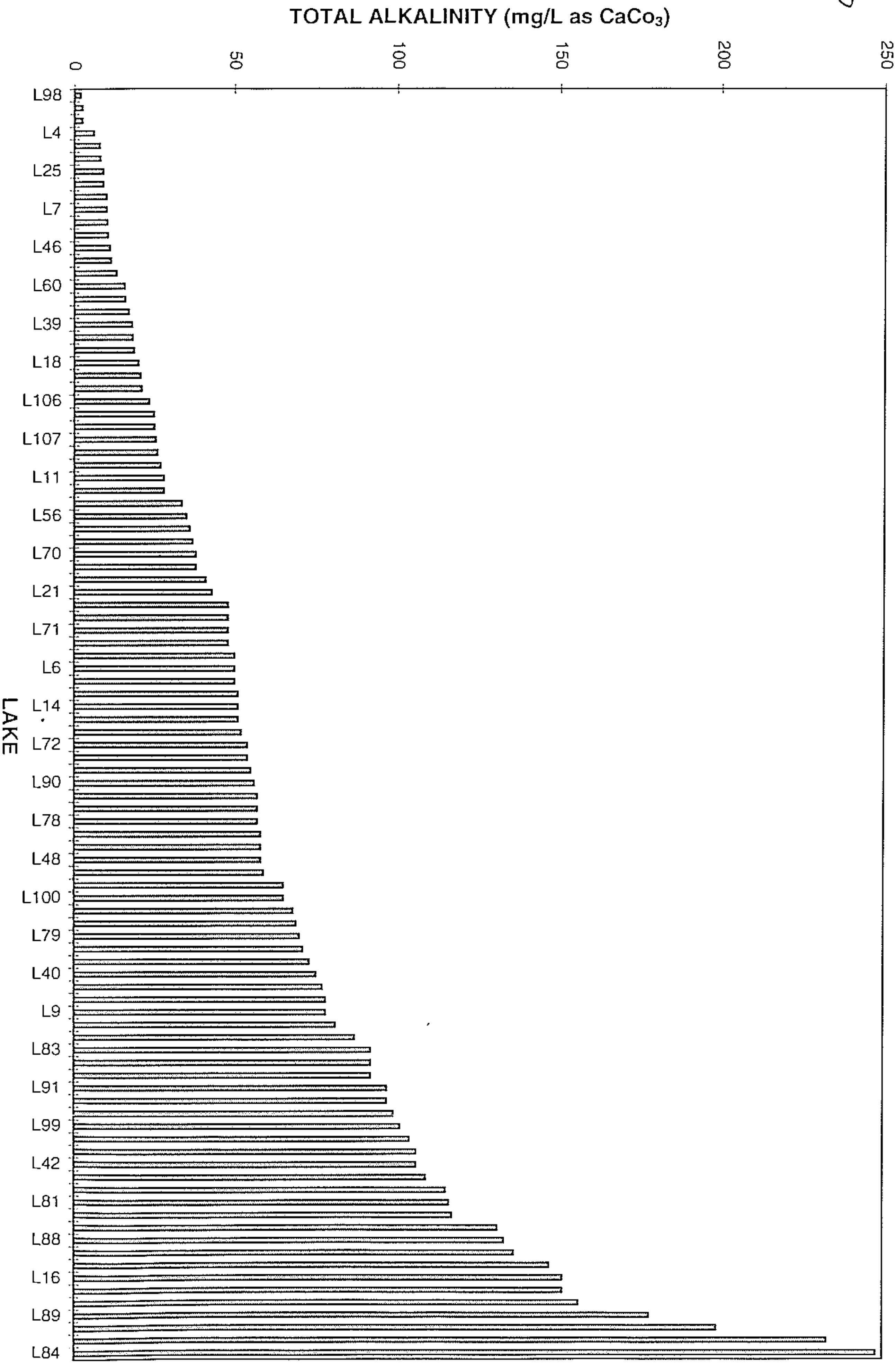


Fig 4

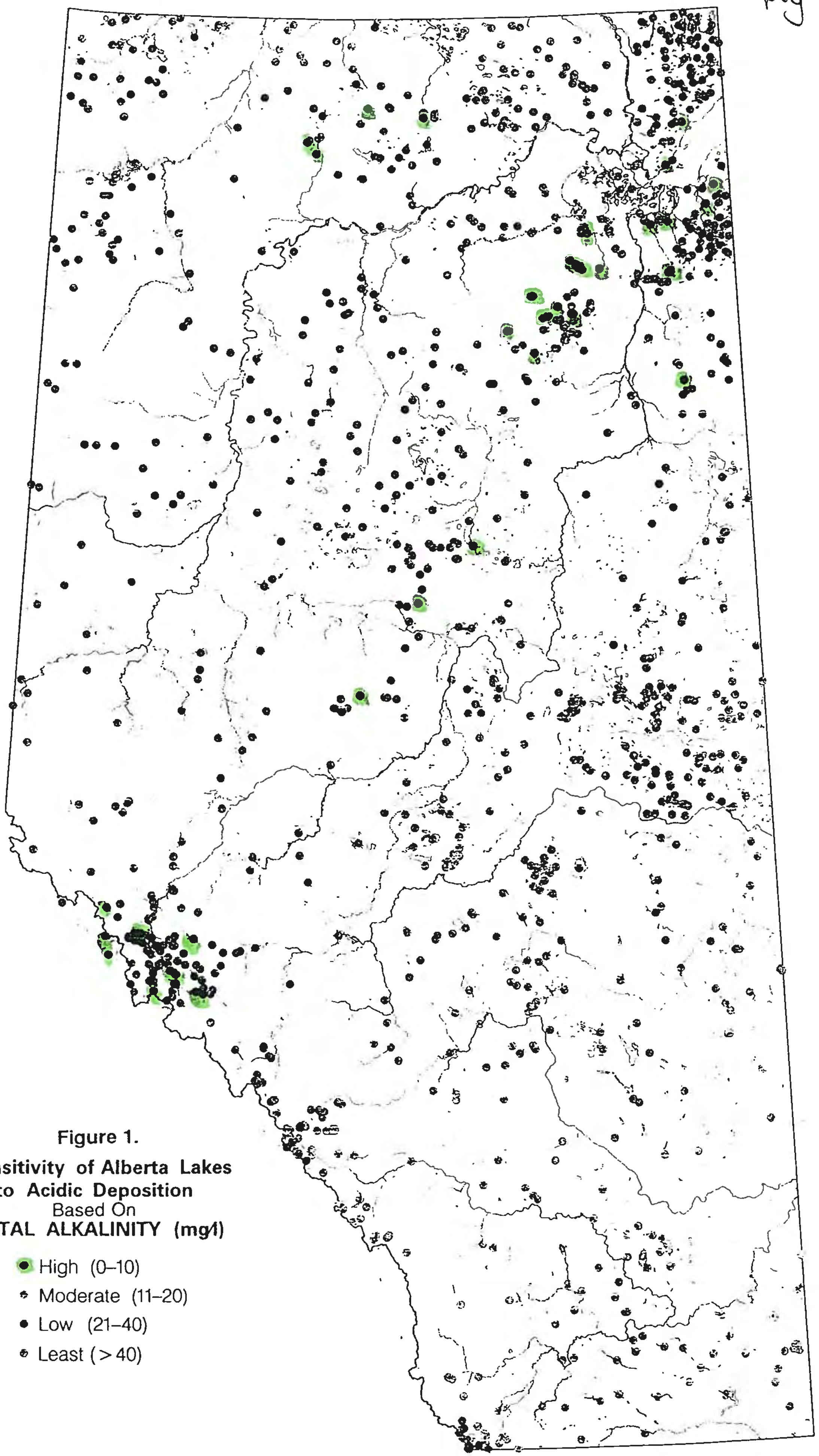
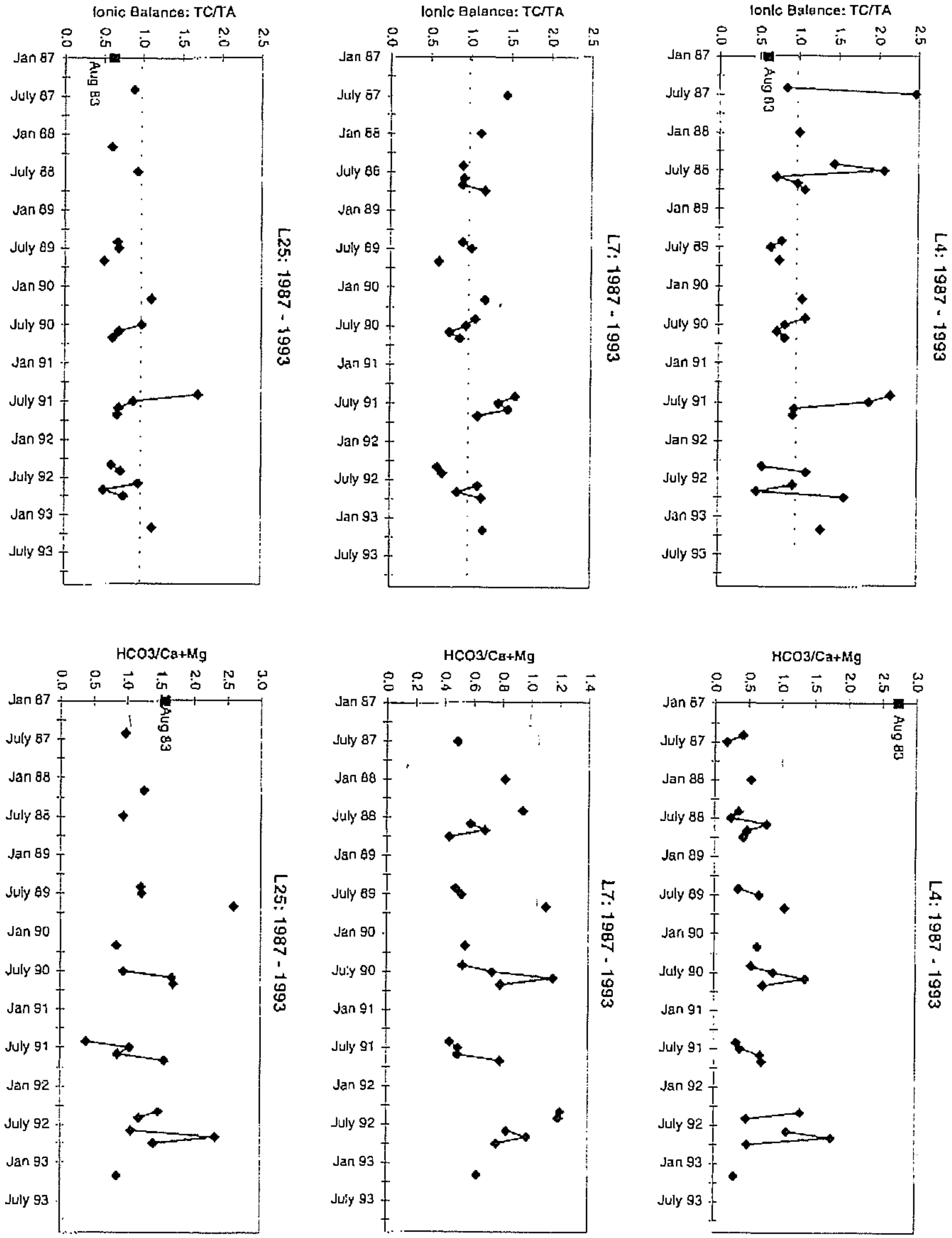


Figure 1.
Sensitivity of Alberta Lakes to Acidic Deposition Based On TOTAL ALKALINITY (mg/l)

Fig 6



Ionic Balance: TC/TA
L4: 1987 - 1993
L7: 1987 - 1993
L25: 1987 - 1993
0.0
0.5
1.0
1.5
2.0
2.5
Aug 83
HCO3/Ca+Mg
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
3.0
Jan 87
July 87
Jan 88
July 88
Jan 89
July 89
Jan 90
July 90
Jan 91
July 91
Jan 92
July 92
Jan 93
July 93

Figure 7

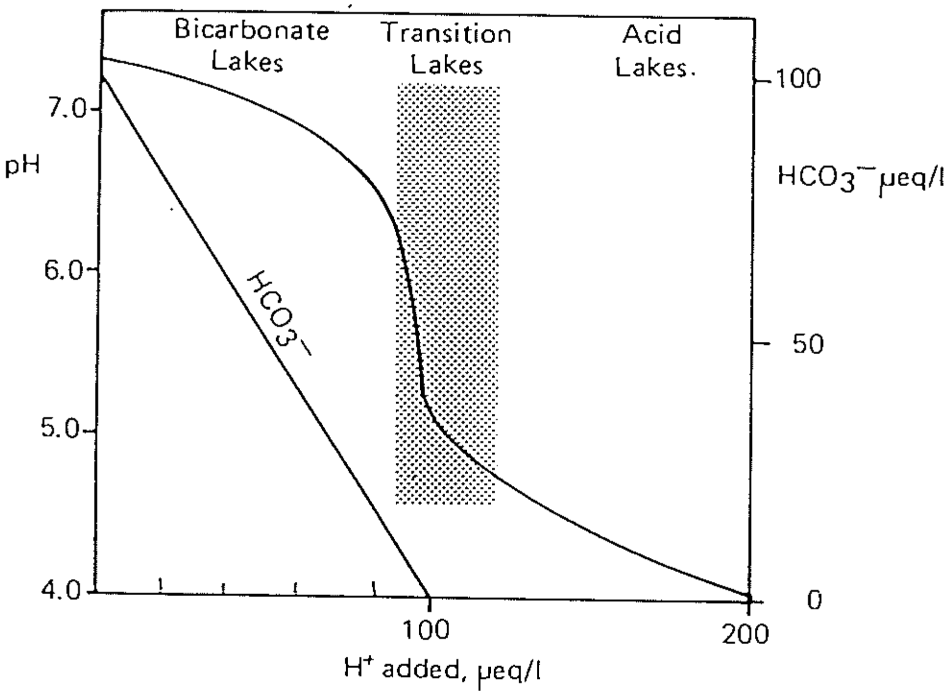
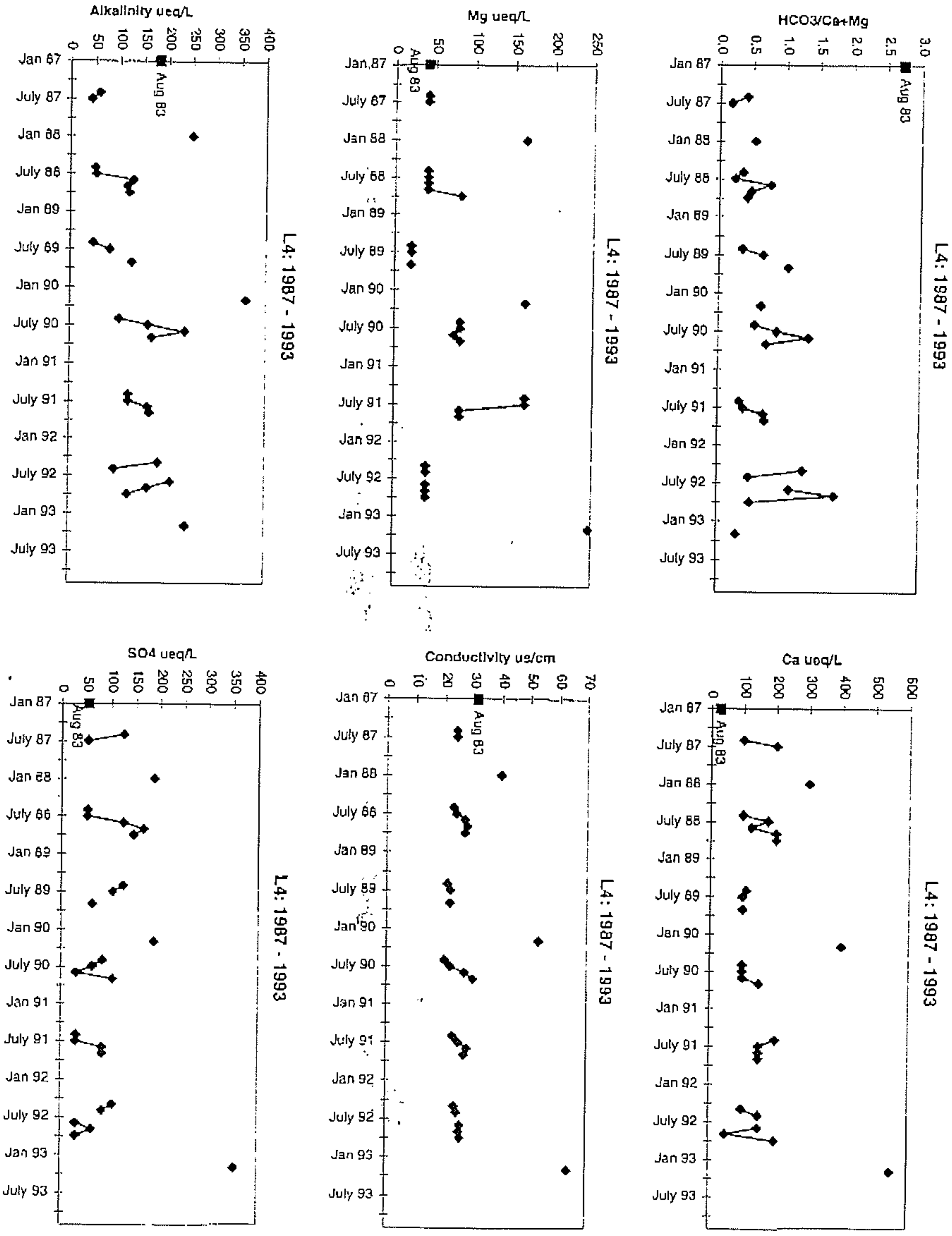


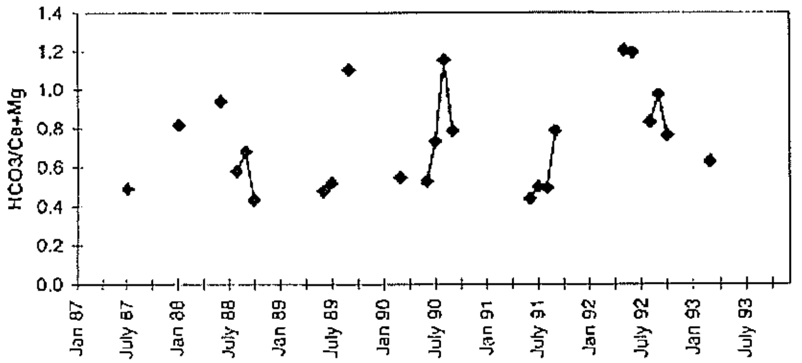
Fig. 4. Titration curve for bicarbonate solution at a given concentration (100µeq/l) that illustrates the acidification process.

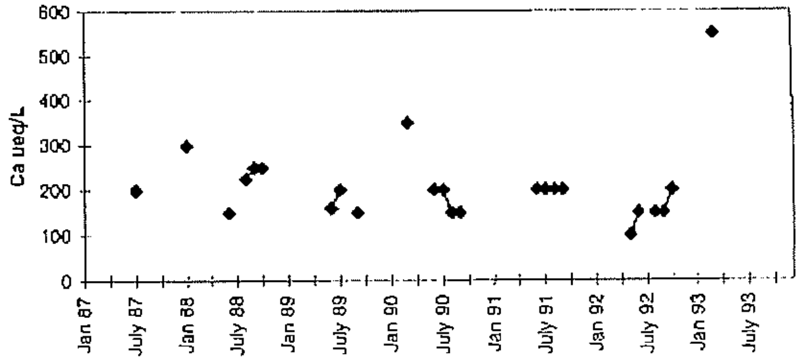
Fig 8

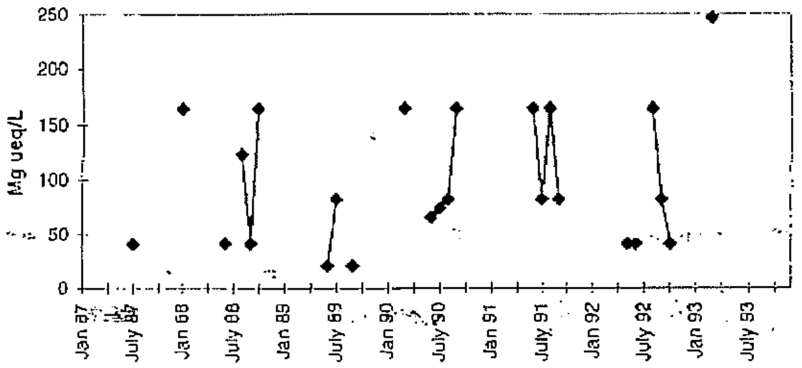

Alkalinity ueq/L
0 50 100 150 200 250 300 350 400
Mg ueq/L
0 50 100 150 200 250
HCO3/Ca+Mg
0.0 0.5 1.0 1.5 2.0 2.5 3.0
SO4 ueq/L
0 50 100 150 200 250 300 350 400
Conductivity us/cm
0 10 20 30 40 50 60 70
Ca ueq/L
0 100 200 300 400 500 600
Jan 87
July 87
Jan 88
July 88
Jan 89
July 89
Jan 90
July 90
Jan 91
July 91
Jan 92
July 92
Jan 93
July 93
Aug 83
L4: 1987 - 1993

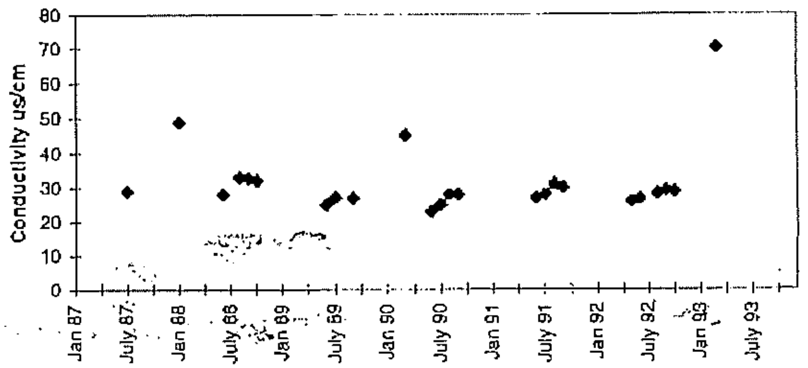
DCC 4/7/95

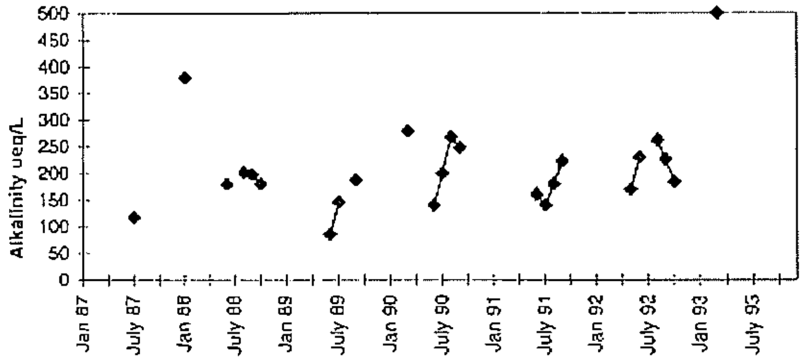
Fig 9

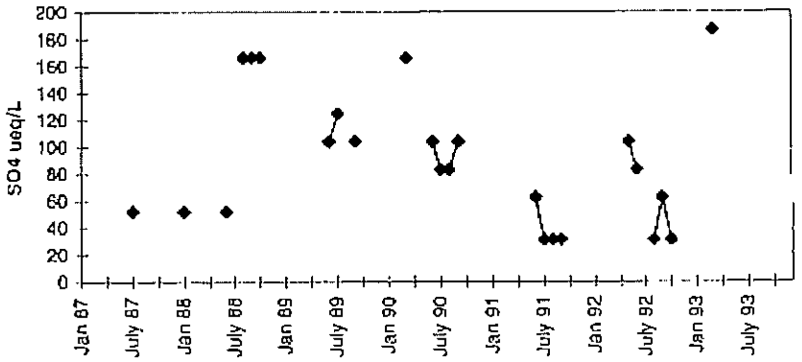

L7: 1987 - 1993


L7: 1987 - 1993


L7: 1987 - 1993


L7: 1987 - 1993

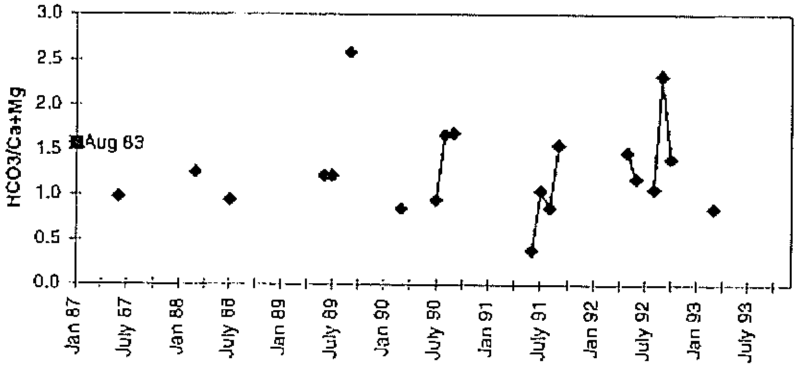

L7: 1987 - 1993


L7: 1987 - 1993

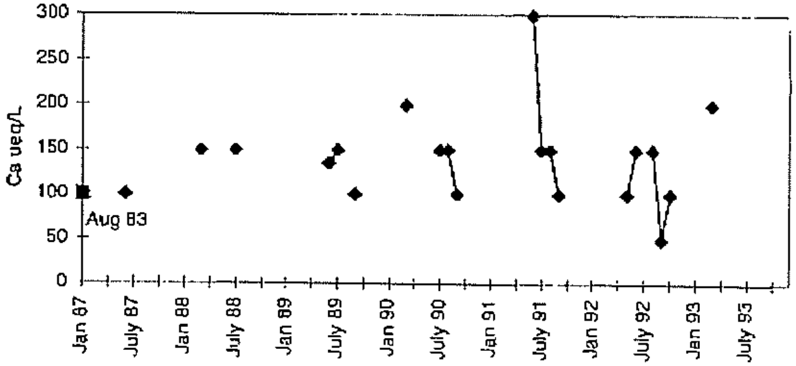
Aug 10

Dec 21/95

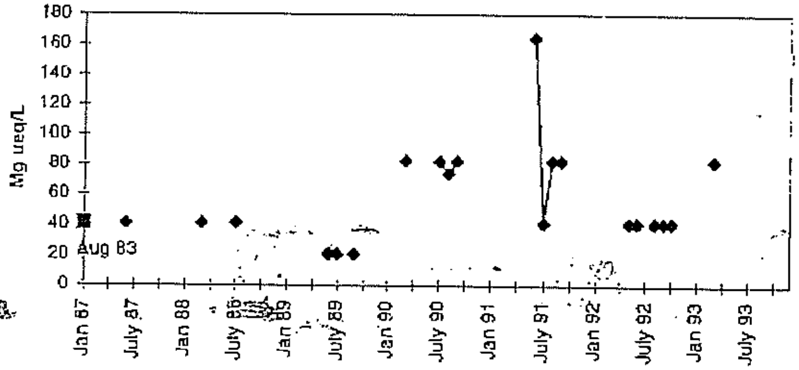
L25: 1987 - 1993



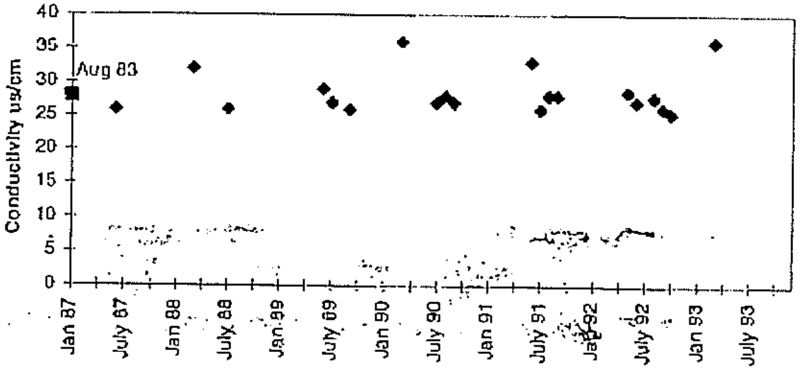
L25: 1987 - 1993



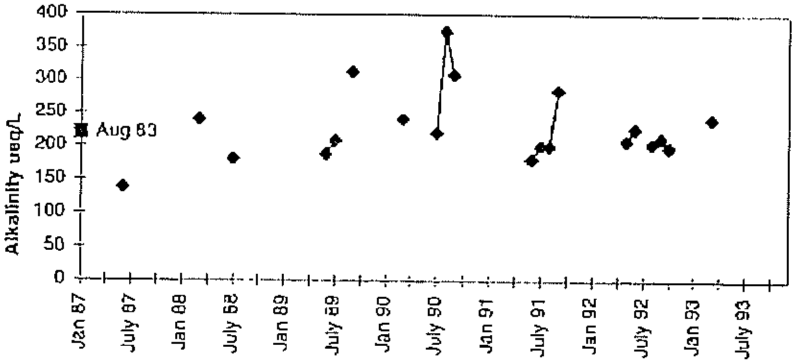
L25: 1987 - 1993



L25: 1987 - 1993



L25: 1987 - 1993



L25: 1987 - 1993

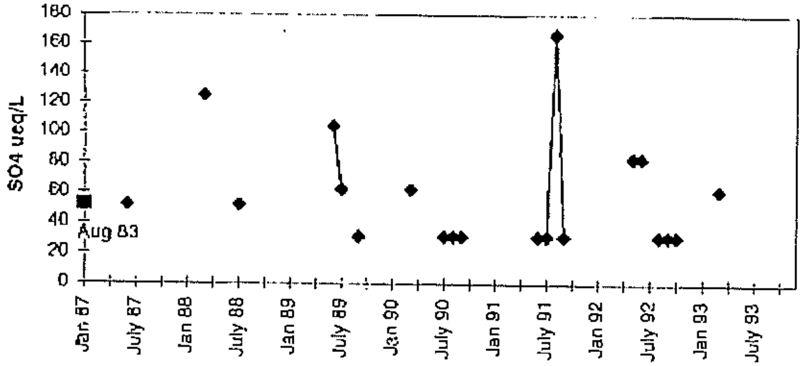
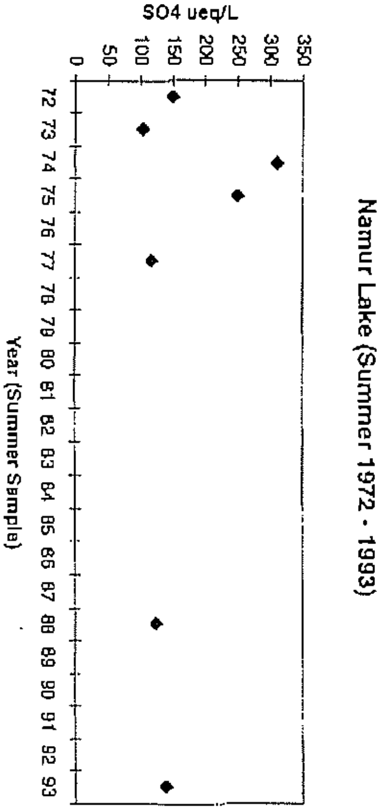
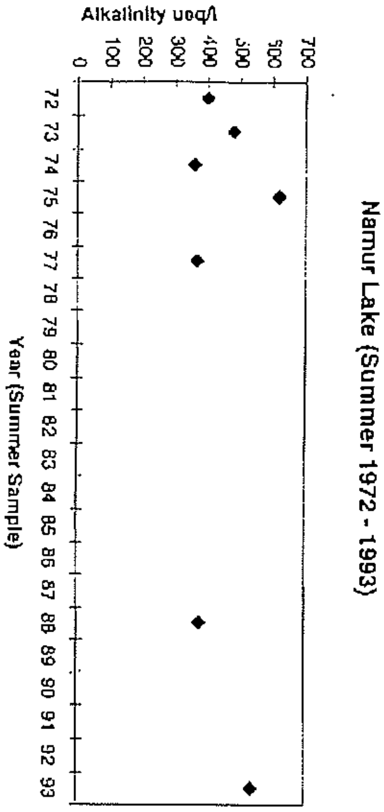


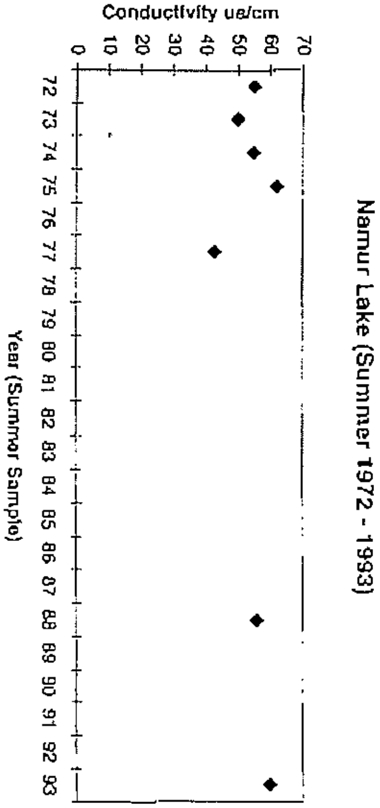
Fig 11



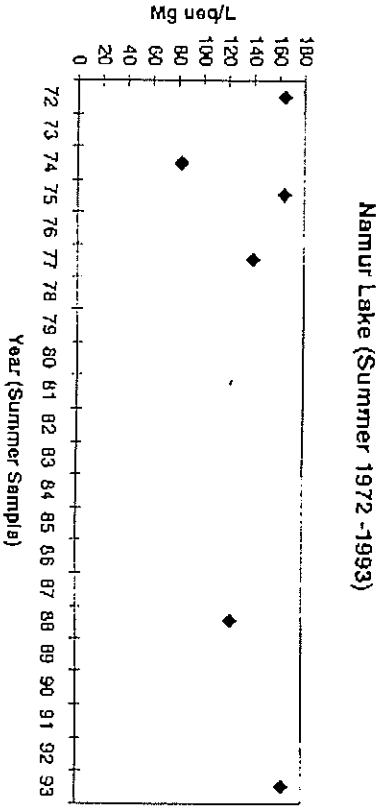
Namur Lake (Summer 1972 - 1993)
SO4 ueq/L
0
50
100
150
200
250
300
350
Year (Summer Sample)
72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93



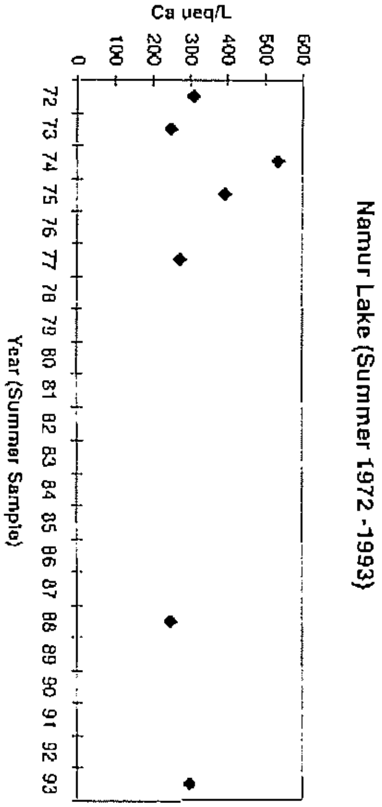
Namur Lake (Summer 1972 - 1993)
Alkalinity ueq/l
0
100
200
300
400
500
600
700
Year (Summer Sample)
72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93



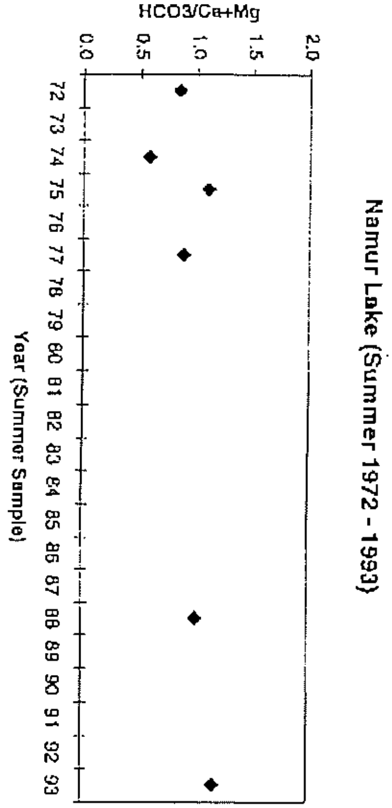
Namur Lake (Summer 1972 - 1993)
Conductivity us/cm
0
10
20
30
40
50
60
70
Year (Summer Sample)
72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93



Namur Lake (Summer 1972 -1993)
Mg ueq/L
0
20
40
60
80
100
120
140
160
180
Year (Summer Sample)
72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93

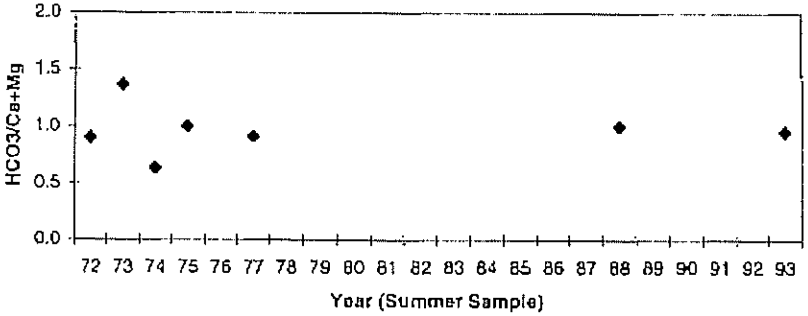


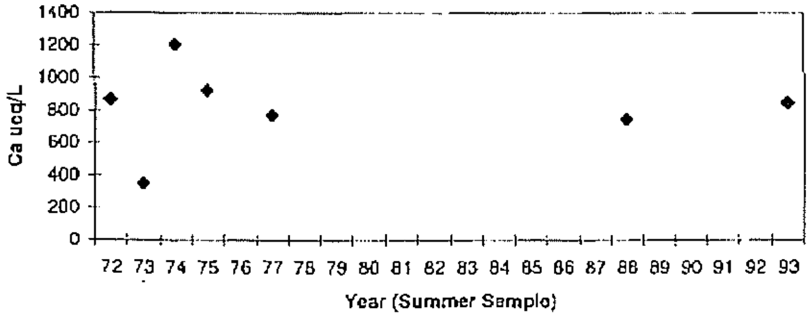
Namur Lake (Summer 1972 -1993)
Ca ueq/L
0
100
200
300
400
500
600
Year (Summer Sample)
72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93

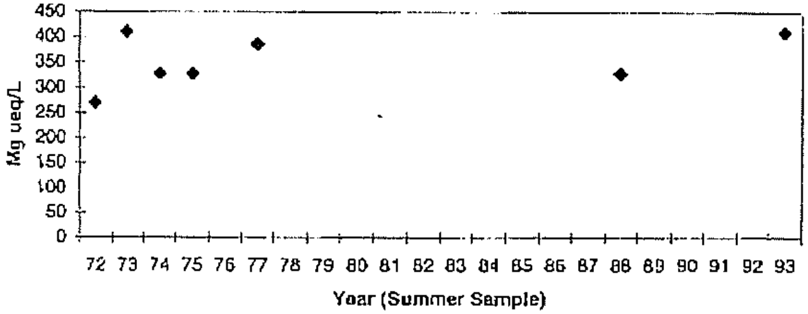


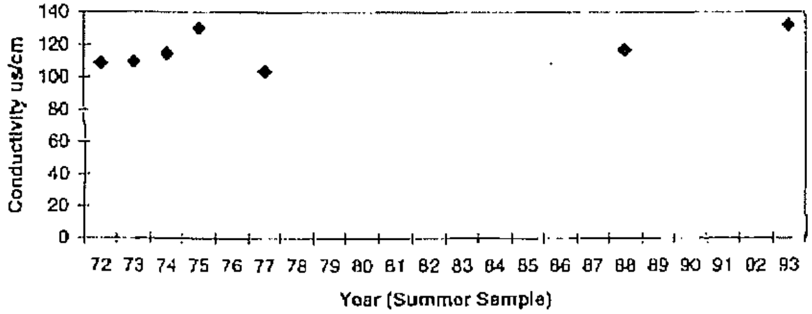
Namur Lake (Summer 1972 - 1993)
HCO3/Ca+Mg
0.0
0.5
1.0
1.5
2.0
Year (Summer Sample)
72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93

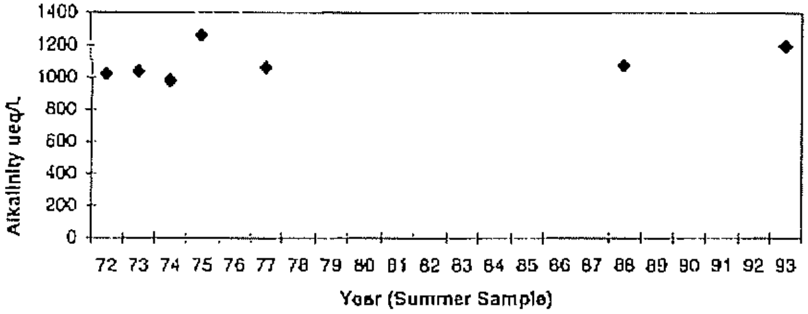
Fig 12


Gardiner Lake (Upper, North Summer 1972 - 1993)


Gardiner Lake (Upper, North Summer 1972 - 1993)


Gardiner Lake (Upper, North Summer 1972 - 1993)


Gardiner Lake (Upper, North Summer 1972 - 1993)


Gardiner Lake (Upper, North Summer 1972 - 1993)

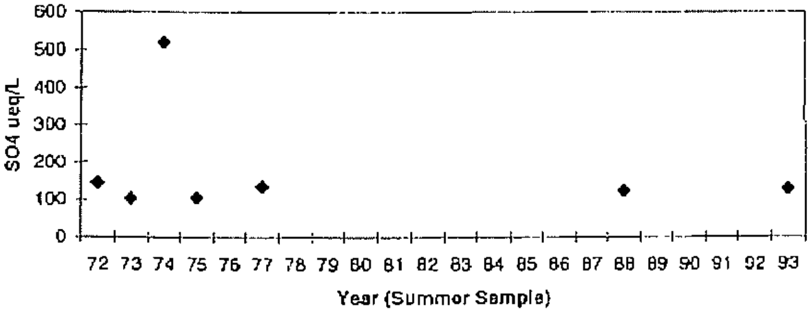
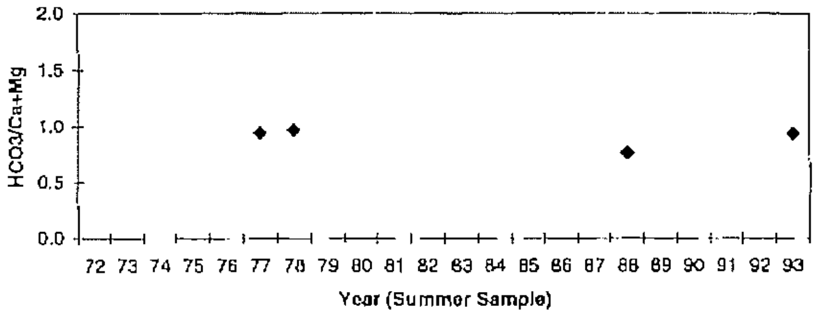
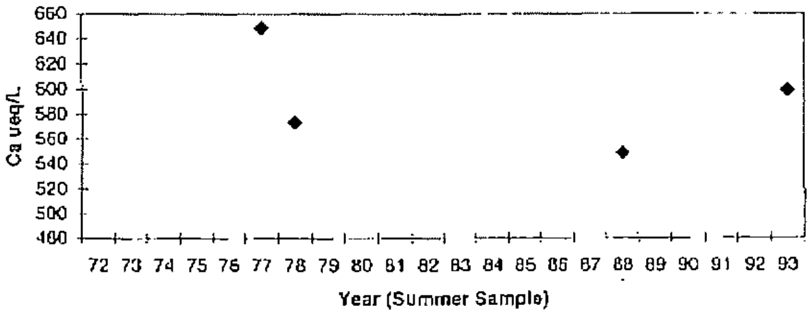

Gardiner Lake (Upper, North Summer 1972 - 1993)

Fig 13

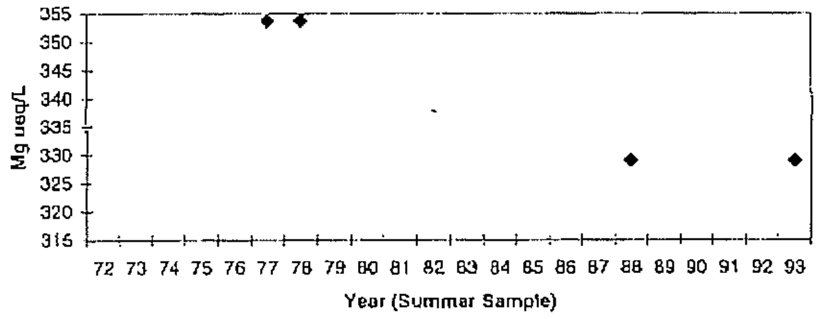
Eaglenest Lake (Summer 1972 - 1993)



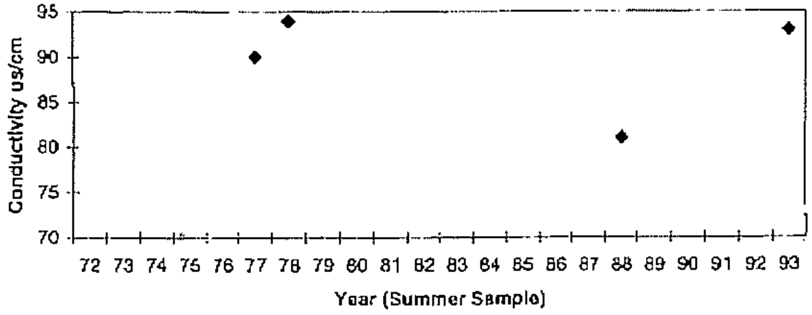
Eaglenest Lake (Summer 1972 - 1993)



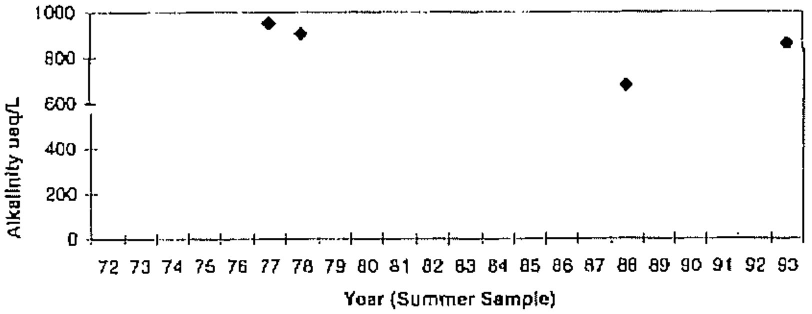
Eaglenest Lake (Summer 1972 - 1993)



Eaglenest Lake (Summer 1972 - 1993)



Eaglenest Lake (Summer 1972 - 1993)



Eaglenest Lake (Summer 1972 - 1993)

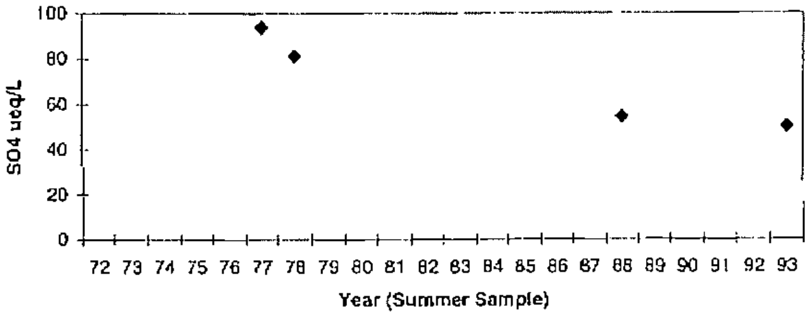
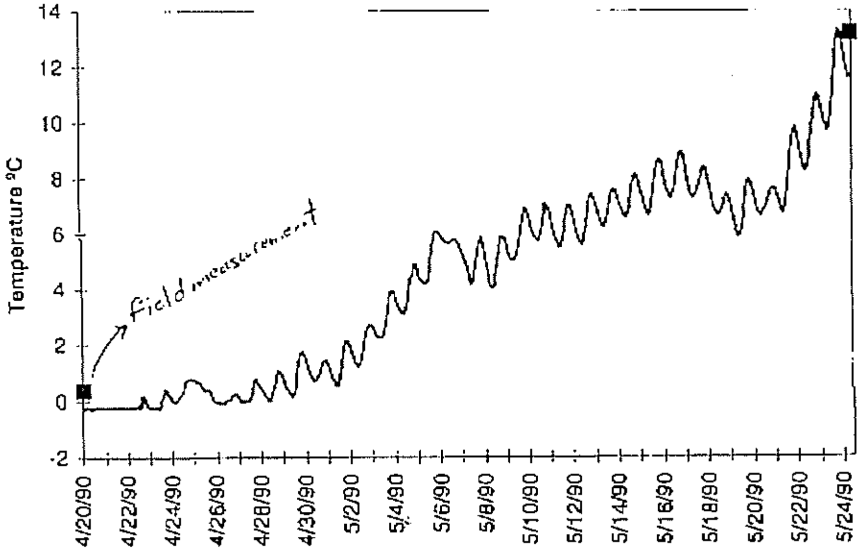
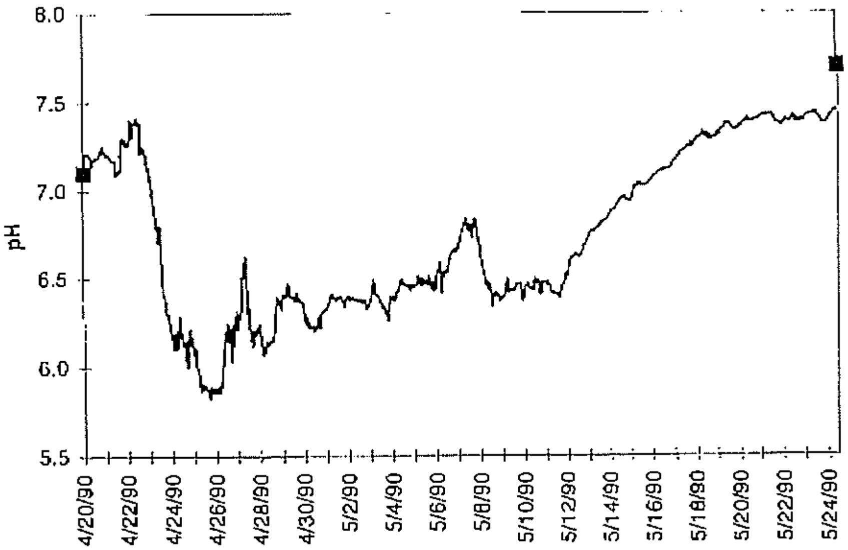


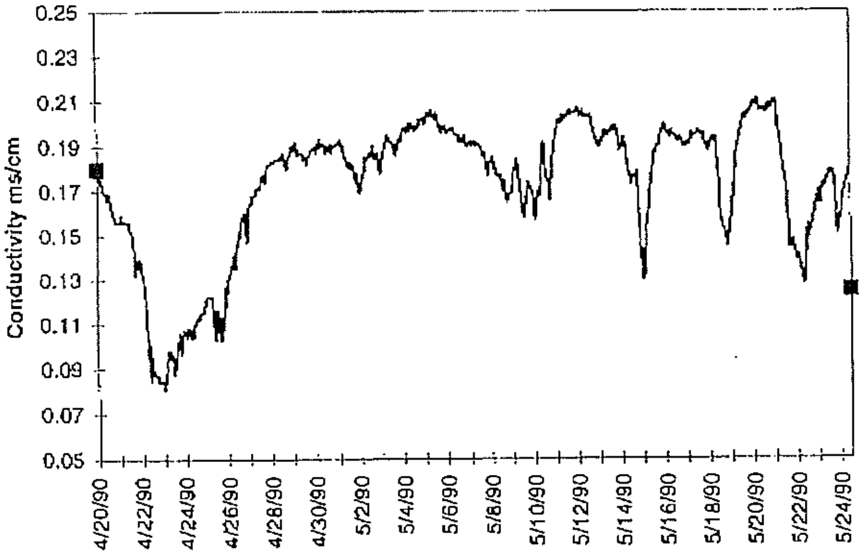
fig 15



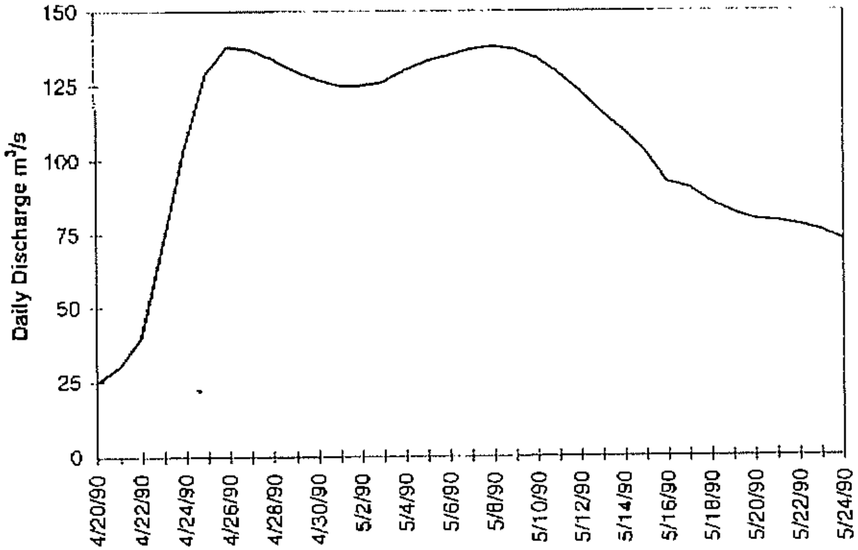
Firebag River near AFS Fire Camp 00AL07DC0594
20 April - 24 May 1990



Firebag River near AFS Fire Camp 00AL07DC0594
20 April - 24 May 1990



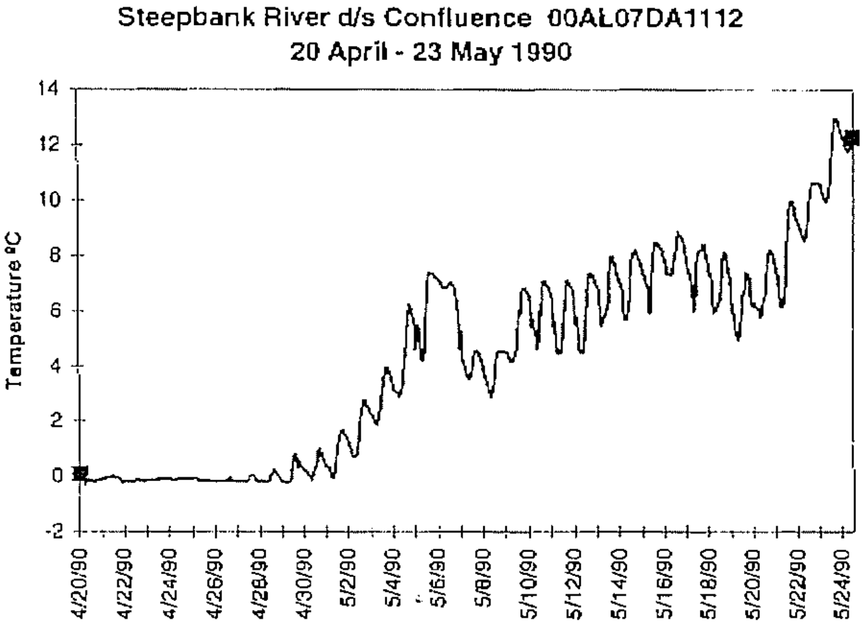
Firebag River near AFS Fire Camp 00AL07DC0594
20 April - 24 May 1990

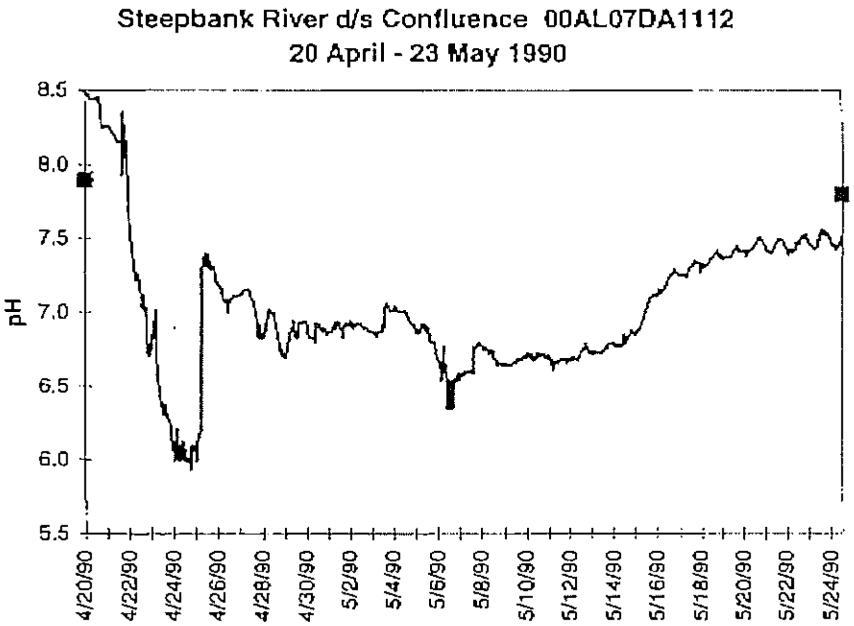


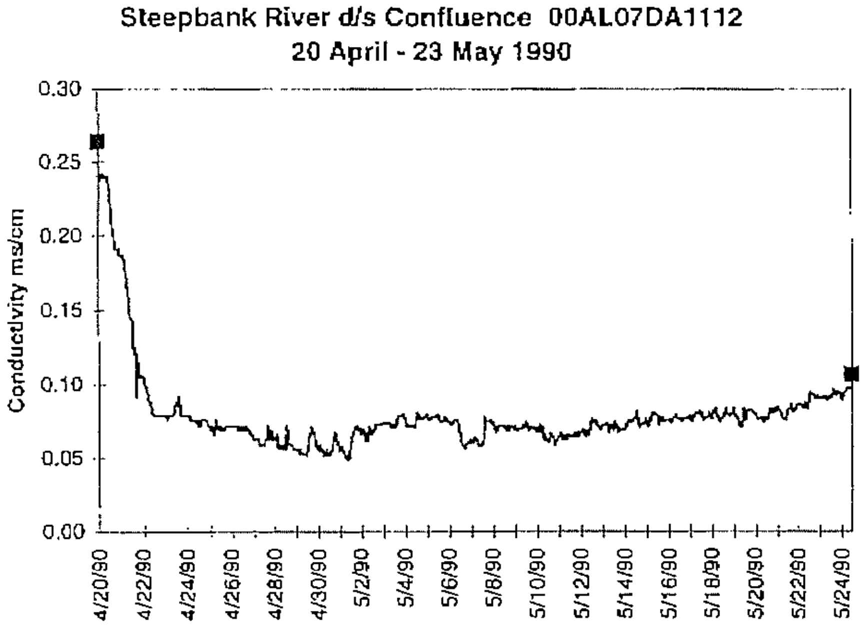
Firebag River Near the Mouth 07DC001
20 April - 24 May 1990

Fig 16

2.5cm


Steepbank River d/s Confluence 00AL07DA1112
20 April - 23 May 1990


Steepbank River d/s Confluence 00AL07DA1112
20 April - 23 May 1990


Steepbank River d/s Confluence 00AL07DA1112
20 April - 23 May 1990

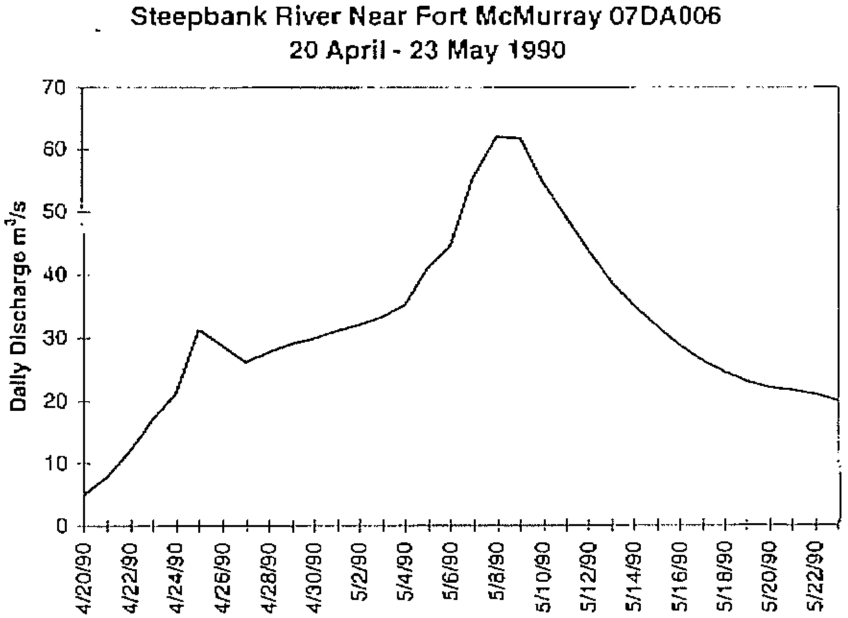
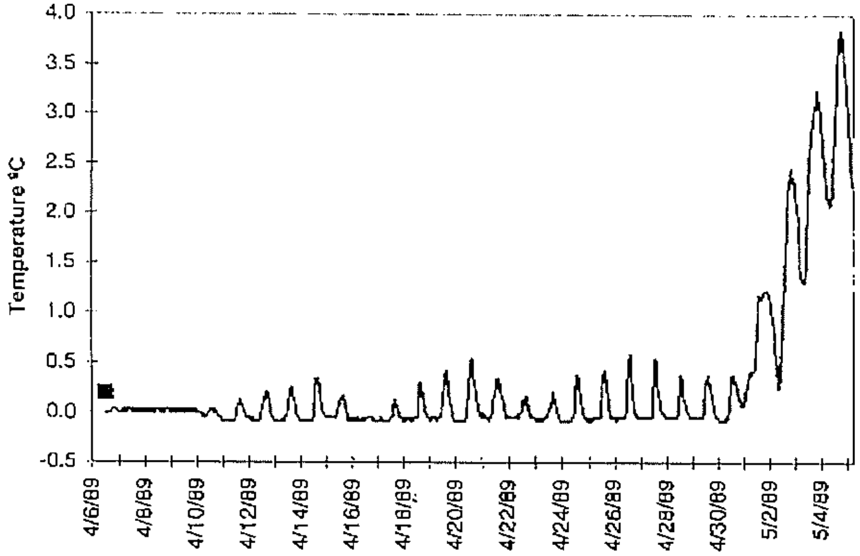
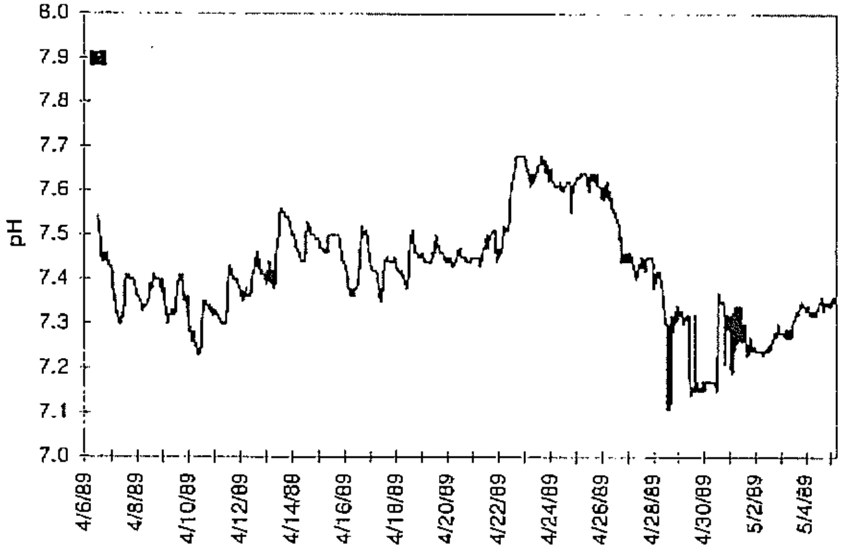

Steepbank River Near Fort McMurray 07DA006
20 April - 23 May 1990

fig 17

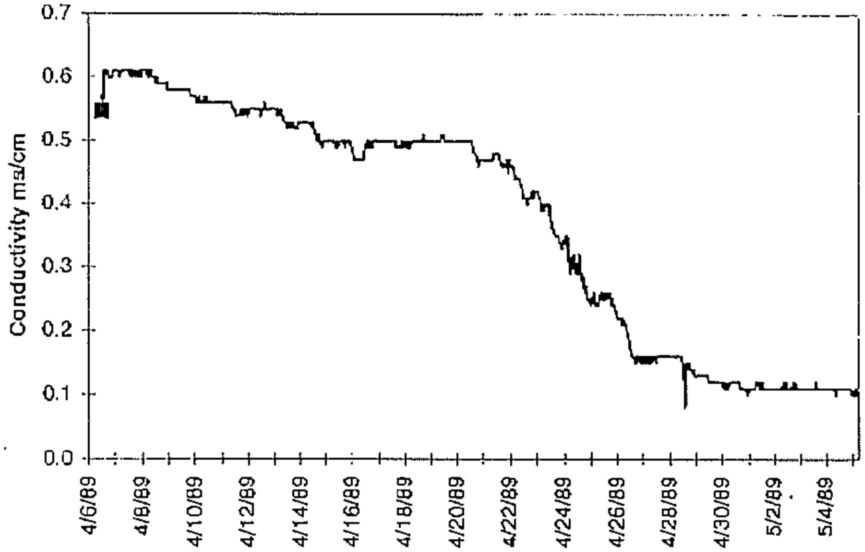
South Steepbank River 00AL07DA1152
6 April - 5 May 1989



South Steepbank River 00AL07DA1152
6 April - 5 May 1989



South Steepbank River 00AL07DA1152
6 April - 5 May 1989



Steepbank River Near Fort McMurray 07DA006
6 April - 5 May 1989

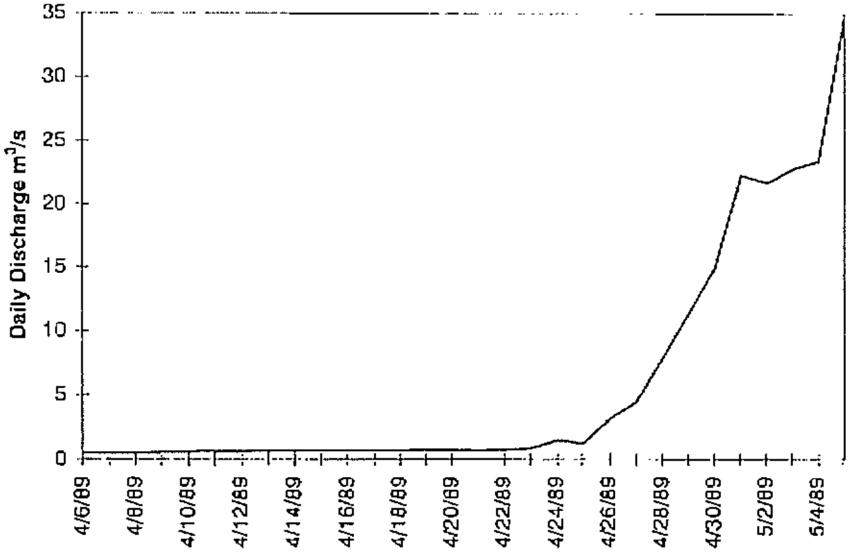


Table 1

Table 7.1 pH, wet deposition rates, and effective acidity of precipitation at monitoring stations which collected samples on a monthly, daily and weekly basis. 1993

Station	Sampling Period	pH^a	Anions (kg/ha)				Cations (kg/ha)					Effective Acidity (kg/ha of eq. H$^+$)
			SO$_4^=$	NO$_3^-$	Cl$^-$	PO$_4^=$	Ca^{++}	NH$_4^+$	Na$^+$	Mg^{++}	K$^+$	
Beaverlodge	weekly	5.0	2.3	1.1	0.2	0.0	0.5	0.3	0.1	0.1	0.1	0.04
Calgary	weekly	5.1	4.8	2.6	0.2	0.0	1.5	1.1	0.1	0.2	0.1	0.07
Cold Lake	weekly	5.3	3.4	2.4	0.4	0.5	1.1	1.9	0.3	0.2	0.5	0.12
Drayton Valley	weekly	5.1	4.8	2.6	0.3	0.1	1.2	1.6	0.3	0.2	0.5	0.10
Fort Chipewyan	weekly	5.0	**	**	**	**	**	**	**	**	**	**
Fort McMurray	weekly	4.7	5.3	1.7	0.3	0.1	1.1	0.5	0.2	0.3	0.3	0.07
Fort Vermilion	weekly	5.2	1.2	0.7	0.3	0.0	0.3	0.2	0.2	0.1	0.1	0.02
High Prairie	daily	5.3	4.3	3.0	0.3	0.1	3.1	0.9	0.3	0.2	0.7	0.06
	weekly	5.1	2.0	1.1	0.2	0.1	0.9	0.3	0.1	0.1	0.2	0.03
Kananaskis	weekly	5.0	7.4	4.0	0.2	0.1	1.6	1.3	0.2	0.3	0.2	0.12
Red Deer	weekly	5.1	4.3	2.7	0.1	0.0	0.8	1.4	0.1	0.1	0.1	0.09
Vegreville (Royal Park)	daily	5.1	6.8	4.9	0.3	0.1	1.5	2.7	0.4	0.2	0.2	0.19
	weekly	5.3	6.8	4.6	0.3	0.1	1.7	2.6	0.3	0.3	0.3	0.16
	monthly	5.3	2.8	1.9	0.1	0.1	0.6	1.3	0.1	0.1	0.1	0.08
Suffield	weekly	5.1	3.3	2.7	0.3	0.1	1.0	1.2	0.8	0.2	0.3	0.07

* ≥50 to <75% of data available.
** Less than 50% of data available.
a Based on the volume weighted average of monthly hydrogen ion concentrations.

or above at all other precipitation quality monitoring stations. The maximum annual average precipitation was recorded at Vegreville, High Prairie and Cold Lake (pH of 5.3). The lowest weekly pH value was recorded at Vegreville (3.53). A maximum weekly pH value of 7.92 was observed at Calgary.

Values of pH were lower in daily samples than weekly and monthly samples at the Vegreville (Royal Park) station. This result is consistent with the findings of Lau (1990). However, pH values from the High Prairie location were slightly higher in daily samples (5.3) when compared to weekly samples (5.1).

7.4.2 Anion Deposition (sulphate, nitrate, chloride and phosphate)

Anions are negatively charged groups of atoms or molecules formed when chemicals dissociate in water. Sulphuric acid and nitric acid produce sulphate and nitrate ions, respectively,

Table 2

Table 11. Damaging deposition rates ($keq(H^+) \cdot ha^{-1} \cdot y^{-1}$) and proposed deposition limits

Current Estimates of $[H^+]$ Deposition in Damaged Areas	
1. Likens et al. (1978) New Hampshire	0.7 to 1.2
2. Scheider and Dillon (1982) Muskoka	0.95
3. Overrein et al. (1980) Norway	1.0
4. Whelpdale (1979) Eastern Canada	0.4 to 0.8
Proposed Surface Water Deposition Limits from Other Areas	
1. Dickson (1986) Sweden	0.15 to 0.40
2. Henriksen et al. (1986) Norway	0.40
3. Schnoor and Stumm (1987) Switzerland	0.20 to 0.50
4. Schuurkes (1986) Netherlands	0.25
5. Harriman (1988) Scotland	0.20 to 0.40
Proposed Surface Water Deposition Limit for Alberta	
1. Alberta Environment	0.1 to 0.3