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REPORT

The Royal Society of Canada Expert Panel:

Environmental and Health Impacts of Canada's Oil Sands Industry

December 2010

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Preface

This is the first in the "new series" of expert panel reports to be commissioned by The Royal Society of Canada / La Société royale du Canada. The Council of the Society, the presidents of its three academies, the past-president of the Society (Professor Yvan Guindon), and the current President, Professor Rod Macdonald, have all strongly supported the commissioning of these new studies, which has renewed the Society's commitment to direct participation in what is the single most important public-service function of national academies. Further details about current and past expert panel reports, as well as the complete text of the earlier series of reports (issued in the period 1996–2004), will be found on the Society's website: www.rsc-src.ca.

Many individuals had a hand in producing this report. First and foremost are the seven members of the expert panel, who produced a comprehensive analysis of the subject, based on an intensive survey of available evidence, in a remarkably short period of time. In agreeing to undertake this considerable task, the panel members were motivated by their awareness of the public-service role of those who contribute their expertise, voluntarily and without remuneration, to the production of national academy reports. They drew upon the support of a number of assistants and researchers, based at the University of Alberta, who are mentioned in the acknowledgments. An earlier draft of the complete report was sent to a group of peer reviewers who were asked to respond with comments on a very tight deadline; the panel members responded in detail to the critical commentary provided by the reviewers. The Society wishes to express its sincere thanks to all who made these indispensable contributions to the report.

The staff of the Society, based in Ottawa, was actively involved in administrative support for the panel meetings and in the preparations for the final production and dissemination of the report, including the attractive cover design and the hosting of the report on the Society's website. Their assistance over the entire course of this project was invaluable.

This report is without a doubt the most comprehensive evidence-based assessment of the full spectrum of major environmental and health impacts of Canada's oil sands industry that has been made available to the public to date. Like any other document of its kind, it is based on the specific perspectives and approaches adopted by its authors. As such it is expected that others will, in response, articulate different and contrasting perspectives. It is our hope that serious and sustained public debate about these very contentious and complex issues will prove to be a benefit to Canadians as well as to interested parties abroad.

William Leiss
Secretary, Committee on Expert Panels
The Royal Society of Canada / La Société royale du Canada
December 15, 2010

REPORT FINDINGS IN BRIEF

Full Executive Summary is available as a separate document.

Major findings in the report addressing health and environmental issues include, in brief:

- **Feasibility of reclamation and adequacy of financial security:** Reclamation is not keeping pace with the rate of land disturbance but research indicates that sustainable uplands reclamation is achievable and ultimately should be able to support traditional land uses. Current practices for obtaining financial security for reclamation liability leave Albertans vulnerable to major financial risks.

- **Impacts of oil sands contaminants on downstream residents:** There is currently no credible evidence of environmental contaminant exposures from oil sands reaching Fort Chipweyan at levels expected to cause elevated human cancer rates. More monitoring focused on human contaminant exposures is needed to address First Nation and community concerns.

- **Impacts on population health in Wood Buffalo**: There is population level evidence that residents of the Regional Municipality of Wood Buffalo (RMWB) experience a range of health indicators, consistent with "boom town" impacts and community infrastructure deficits, which are poorer than those of a comparable Alberta region and provincial averages.

- **Impacts on regional water supply**: Current industrial water use demands do not threaten the viability of the Athabasca River system if the Water Management Framework developed to protect in-stream, ecosystem flow needs is fully implemented and enforced.

- **Impacts on regional water quality and groundwater quantity**: Current evidence on water quality impacts on the Athabasca River system suggests that oil sands development activities are not a current threat to aquatic ecosystem viability. However, there are valid concerns about the current Regional Aquatics Monitoring Program (RAMP) that must be addressed. The regional cumulative impact on groundwater quantity and quality has not been assessed.

- **Tailings pond operation and reclamation**: Technologies for improved tailings management are emerging but the rate of improvement has not prevented a growing inventory of tailings ponds. Reclamation and management options for wet landscapes derived from tailings ponds have been researched but are not adequately demonstrated.

- **Impacts on ambient air quality**: The current ambient air quality monitoring data for the region show minimal impacts from oil sands development on regional air quality except for noxious odour emission problems over the past two years. Control of NOx emissions and regional acidification potential remain valid concerns.

- **Impacts on greenhouse gas emissions (GHG)**: Progress has been made by the oil sands industry in reducing its direct GHG emission per barrel of bitumen produced. Nonetheless, increasing direct GHG emissions from growing bitumen production creates a major challenge for Canada to meet our international commitments for overall GHG emission reduction that current technology options do not resolve.

- **Environmental regulatory performance**: The environmental regulatory capacity of the Alberta and Canadian Governments does not appear to have kept pace with the rapid growth of the oil sands industry over the past decade. The EIA process relied upon by decision-makers to determine whether proposed oil sands projects are in the public interest has serious deficiencies in relation to international best practice. Environmental data access for cumulative impact assessment needs to improve.

Expert Panel Members

Dr. Pierre Gosselin

Dr. Gosselin was trained as a physician (Université Laval) and in environmental health (University of California at Berkeley). He has been involved in environmental and occupational health for the last 30 years in various organizations. He is Clinical Professor in the Faculty of Medicine at Laval University and senior researcher at the Research Centre of Quebec City University Hospital (CHUQ), where he has been the Director of the WHO-PAHO Collaborating Centre on Environmental and Occupational Health since 1998. He has frequently advised the Pan American Health Organization and other WHO regional offices and headquarters, the International Joint Commission, the North American Commission for Environmental Cooperation, Health Canada, and the Public Health Agency of Canada on environmental health matters. He works mostly out of the Quebec Public Health Institute (INSPQ), where he coordinates the joint Ouranos-INSPQ research program in climate change and health. He recently began coordinating the Health component of the Quebec Action Plan on Climate Change (2007–2012).

Dr. Steve E. Hrudey

Dr. Hrudey is currently Professor Emeritus, in the Division of Analytical and Environmental Toxicology in the Faculty of Medicine and Dentistry at the University of Alberta with over 35 years in the environmental health sciences. He has chaired three and served on several expert panels including chairing the RSC panel to Review the Socio-Economic Models and Related Components Supporting the Development of Canada-Wide Standards for Particulate Matter and Ozone, serving the Research Advisory Panel to the Walkerton Inquiry, the Assessment of Health Risks Related to Trihalomethanes for Health Canada, Safe Drinking Water for First Nations for the Minister of Indian and Northern Affairs, Groundwater Management in Canada for the Council of Canadian Academies, Turbidity and Microbial Risk for the B.C. Minister of Health and most recently the Future Treatment Alternatives Study for the U.S. Army Corps of Engineers concerning drinking water for Washington, D.C. Dr. Hrudey was elected a Fellow of the International Water Association in 2010, a Fellow of the Society for Risk Analysis in 2007, and a Fellow of the Academy of Sciences, Royal Society of Canada in 2006.

Dr. M. Anne Naeth

Dr. M. Anne Naeth, P.Ag., P.Biol., is currently Professor of Land Reclamation and Ecological Restoration, in the Faculty of Agricultural, Life, and Environmental Sciences, and Vargo Distinguished Teaching Chair, at the University of Alberta with almost 35 years in the environmental sciences. Dr. Naeth has served on several expert advisory panels and boards for Alberta Sustainable Resource Development and Environment Canada (greenhouse gases), Canadian Wildlife Service (biodiversity), Alberta Environment (pipeline soils handling), Ducks Unlimited, North American Waterfowl Management Plan, Parks Canada, and the Nature Conservancy of Canada. She is currently leading development of an international graduate school in land reclamation. Dr. Naeth was elected a Fellow of the Canadian Society of Soil Science in 2007, and a Fellow of the Society for Teaching and Learning in Higher Education in 1997. She was awarded the Canadian Land Reclamation Association Noranda Award for outstanding contributions to the field of land reclamation in Canada in 1996.

Dr. André Plourde

André Plourde is currently Professor in the Department of Economics at the University of Alberta. He has previously held academic appointments at the University of Toronto and the University of Ottawa. To date, his career has also included two periods of service in leadership roles in the federal government departments of Finance and Natural Resources Canada. In 1994, he chaired the Task Force on Economic Instruments and Disincentives to Sound Environmental Practices for the federal ministers of Environment and Finance. Dr. Plourde has also served on the National Advisory Council on Energy Efficiency, the Energy Sector Sustainability Table (Environment Canada), and the Environmental Protection Advisory Committee (Alberta Minister of Environment), among others. In 2007, he was President of the International Association for Energy Economics and served as a member of the Government of Alberta's Royalty Review Panel.

Dr. Réné Therrien

Dr. Therrien has a PhD in hydrogeology from the University of Waterloo and is currently Professor and Chair of the Department of Geology and Geological Engineering at Université Laval. He has served on the expert panel on the Sustainable Management of Groundwater in Canada for the Council of Canadian Academies and is currently member of the commission examining the sustainable development of the shale gas industry in Québec within the Bureau d'audiences publiques sur l'environnement. He is also the current chair of the Healthy Environment and Ecosystems Panel within the Natural Science and Engineering Research Council's Strategic Projects Program. He was previously a member of the Minister's National Advisory Board for the Earth Sciences for Natural Resources Canada and a member of the Canadian Geotechnical Research Board.

Dr. Glen Van Der Kraak

Dr. Glen Van Der Kraak is a Professor in the Department of Integrative Biology and the Associate Dean for Research in the College of Biological Science at the University of Guelph. He has published over 250 refereed journal articles, reviews, and book chapters, and has written or edited four books. He has extensive experience in the testing of chemicals and complex effluents for effects on the reproductive physiology of fish and amphibians. Dr. Van Der Kraak won the Award for Excellence in Research by the University of Guelph chapter of Sigma Xi in 2002. He has served on two panels of the World Health Organization's International Program on Chemical Safety evaluating risks posed by endocrine disrupting chemicals and methods of integrating human health and ecological risk assessments. He has frequently served as an advisor to the U.S. Environmental Protection Agency including serving as a member of the Endocrine Disruptors Methods Validation Sub Committee, the Endocrine Disruptors Methods Validation Advisory Committee, and the Board of Scientific Counsellors that reviewed the US EPA's Endocrine Disruptors Research Program.

Dr. Zhenghe Xu

Dr Xu is Teck Professor in the Faculty of Engineering at the University of Alberta. He has authored or co-authored 220 refereed journal articles, 50 technical conference proceeding papers, nine invited book chapters and he holds two U.S. patents. His research expertise includes interfacial phenomena, oil sands engineering, surface engineering with emphasis on nano materials technology and mesoporous nanocomposites, mineral and materials processing and recycling, coal cleaning technology, waste management, and pollution control. Dr. Xu held an NSERC/EPCOR/AERI Industry Research Chair in Advanced Coal Cleaning and Combustion Technology from 2002 to 2007, and he was appointed as a Canada Research Chair (Tier I) in Mineral Processing in 2006 and a NSERC Industry Research Chair in Oil Sands Engineering in 2008. He was elected a Fellow of the Canadian Academy of Engineering in 2008 and a Fellow of the Canadian Institute of Mining, Metallurgy and Petroleum in 2010.

Acknowlegements

The authors of this report are entirely responsible for its content. Others who made substantial contributions or assisted with review of drafts, but who should not be held responsible for the final report content are: Dr. Jacob Masliyah, Dr. Murray Gray, and Dr. Jinwen Chen (Section 4), Ms. Teresa Bisson (Section 6), Dr. Xiangfei Fayanna Li (Section 7), Dr. David Chanasyk and Dr. Brett Purdy (Section 9), Mr. Chris Powter (Sections 5 and 9) and Ms. Annie St. Amand (Sections 10 and 11). Figure 3.3 was created by Mr. Rick Pelletier; satellite image was derived from the EarthSat NaturalVue Global Landsat Mosaic from Earth Satellite Corporation (EarthSat), published by ESRI, 20080401. University of Alberta Creative Services, Ms. Leslie Stewart and Ms. Elise Almeida provided graphic services in redrawing figures from various sources. Mrs. Elizabeth Hrudey assisted with panel logistics, meeting recording, and proof-reading of various drafts. Ms. Katerina Carastathis provided report editing, proof-reading, formatting and logistical support to the panel.

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Acronyms, Abbreviations, and Definitions

ACR Alberta Chamber of Resources
AEAB Alberta Environmental Appeals Board
AENV Alberta Environment
AEUB Alberta Energy and Utilities Board
AHCIP Alberta Healthcare Insurance Plan
AHS Alberta Health Services
AHW Alberta Health and Wellness
AMEC an international consulting firm formed from the UK-based Matthew Hall Group and Canada-based Montreal Engineering
AOSERP Alberta Oil Sands Environmental Research Program
AOSTRA Alberta Oil Sands Technology and Research Authority
API American Petroleum Institute
bbl barrel of oil, 0.159 m^3
BOD biochemical oxygen demand
BATEA best available technology economically achievable
BTEX benzene, toluene, ethylbenzene, and xylene
CAPP Canadian Association of Petroleum Producers
CASA Clean Air Strategic Alliance (an Alberta multistakeholder initiative)
CCME Canadian Council of Ministers of the Environment
CCS carbon capture and storage (sequestration)
CEAA Canadian Environmental Assessment Agency
CEMA Cumulative Environmental Management Association
CEPA Canadian Environmental Protection Act
CERI Canadian Energy Research Institute
CDC Centres for Disease Control
CH_4 methane
CNRL Canadian Natural Resources Ltd.
CO_2e carbon dioxide equivalent

$$E_{Total} = \sum_{i=1}^{n}(E_{CO_2,i} \times G_{CO_2}) + \sum_{i=1}^{n}(E_{CH_4,i} \times G_{CH_4}) + \sum_{i=1}^{n}(E_{N_2O,i} \times G_{N_2O})$$

where:
E_{Total} = the total carbon dioxide equivalent (CO_{2e}) tonnes of GHG emitted by an oil sands facility in a given calendar year
E_{CO2}, E_{CH4}, E_{N2O} = tonnes of CO_2, CH_4, and N_2O emitted
G_{CO2}, G_{CH4}, G_{N2O} = the global warming potential multiplier of CO_2 (1), CH_4 (21), and N_2O (310), respectively
i = each individual source of emissions
n = number of emissions sources

CO carbon monoxide
CONRAD Canadian Oilsands Network for Research and Development
CCO conventional crude oil – usually refers to light, medium, and heavy hydrocarbons produced by drilling wells
CPSA College of Physicians and Surgeons of Alberta
C&R Conservation and Reclamation Regulation, EPEA
CSS cyclic steam stimulation
CT consolidated or composite tailings
CWS Canada-wide Standard
Da dalton
DRU diluent recovery unit
EAB Alberta Environmental Appeals Board (see AEAB)

EIA	environmental impact assessment
EOR	enhanced oil recovery
EPL	end pit lake
EPEA	Environmental Protection and Enhancement Act
ERCB	Energy Resources Conservation Board
ERRG	Environmental and Reclamation Research Group
EROD	ethoxyresorufin-O-deethylase activity, a biomarker of chemical exposure
ET-DSP	Electro-Thermal Dynamic Stripping Process
EUB	Alberta Energy and Utilities Board (see AEUB)
FT–IR	Fourier transform–infrared
GCOS	Great Canadian Oil Sands
GC–MS	gas chromatography–mass spectrometry
GDP	gross domestic product
GHG	greenhouse gas
GJ	gigajoules, 10^9 joules
H_2S	hydrogen sulphide
ha	hectare, 0.01 km^2
HAOC	health areas of concern
HEMP	Human Exposure Monitoring Program, Alberta Health and Wellness
HHRA	human health risk assessment
HIA	health impact assessment
HNA	health needs assessment
HRA	health risk assesment
IAIA	International Association for Impact Assessment
ICMM	International Council on Mining and Metals
ICO_2N	a joint venture of several oil companies to explore CCS
IFC	International Finance Corporation (World Bank)
IHDA	Interactive Health Data Application
ILCR	incremental lifetime cancer risk
INAC	Indian and Northern Affairs Canada
IPCC	Intergovernmental Panel on Climate Change
IPIECA	International Petroleum Industry Environmental Conservation Association
IRIS	Integrated Risk Information System, toxicological data base of the U.S. EPA
km	kilometre, 1000 m
kPa	kilopascals, 1,000 Pa
kt	kilotonne
LCCS	Land Capability Classification System
LFH	leaf, fibric, humic
LFP	Large Facility Liability Management Program
LLR	licensee liability rating
LMR	liability management rating
LOAEL	lowest observed adverse effect level
LOC	License of Occupation
m^2	square metre
m^3	cubic metre
MBCA	Migratory Birds Convention Act
MFT	mature fine tailings
MLA	Member of the Legislative Assembly, Alberta
MOU	memorandum of understanding
MSL	Mineral Surface Lease
NA	naphthenic acids

NAS	National Academy of Sciences (U.S.)
NCCHPP	National Collaborating Centre for Healthy Public Policy, Public Health Agency of Canada
NEB	National Energy Board of Canada
NEP	National Energy Program
NG	natural gas
NGO	non-governmental organization
NH_3	ammonia
NLHR	Northern Lights Health Region
NOSTF	National Oil Sands Task Force
NO_x	oxides of nitrogen
NO_2	nitrogen dioxide
NRBS	Northern River Basin Study
NREI	Northern Rivers Ecosystem Initiative, Environment Canada
NPRI	National Pollutant Release Inventory, Environment Canada
NWPA	Navigable Waters Protection Act
OECD	Organisation for Economic Co-operation and Development
OGP	International Association of Oil and Gas Producers
OSA	oil sands areas
OSCA	Oil Sands Conservation Act
OSPW	Oil sands process wastewater
OWA	Orphan Well Association (Alberta Oil and Gas Orphan Abandonment and Reclamation Association
OWL	Oilfield Waste Liability
PACs	polycyclic aromatic compounds
PAHs	polycyclic aromatic hydrocarbons
PASHs	polycyclic aromatic sulphur heterocycles
PHA	Public Halth Act
PLA	Public Lands Act
PM_x	particulate matter of median diameter “x”µm, 10^{-6} m
PSC	particulate separation cells
RAMP	Regional Aquatics Monitoring Program
RMWB	Regional Municipality of Wood Buffalo
RSC	Royal Society of Canada
RSDS	Regional Sustainable Development Strategy
SAGD	steam assisted gravity drainage
SBP	sulphur by-product
SCF	standard cubic foot
SCO	synthetic crude oil
SER	Society for Ecological Restoration
SFR	sand-to-fines ratio
SLC	sour light crude oil
SMC	sour medium crude oil
SO_x	oxides of sulphur
SO_2	sulphur dioxide
SOR	steam-to-oil ratio
SPMD	semi-permeable membrane device
SRA	Surface Rights Act
SRD	Sustainable Resources Development (Alberta)
THAI	toe-to-heel air injection
THC	total hydrocarbons
TMAC	Trace Metals and Air Contaminants Working Group of CEMA
TOR	tailings oil recovery

ToR	Terms of Reference
TRS	total reduced sulphur
TT	thickened tailings
UNFCCC	United Nations Framework Convention on Climate Change
USEPA	U.S. Environmental Protection Agency
VAPEX	vapour extraction process
VOCs	volatile organic compounds
WA	Water Act
WBEA	Wood Buffalo Environmental Association
WCSB	Western Canada Sedimentary Basin

PART 1 BACKGROUND

1. INTRODUCTION

1.1 Rationale for an Independent Review

The oil sands deposits in northern Alberta have become a focus of intense development in recent years. Indeed, bitumen and synthetic crude oil production from the oil sands has in the past decade reached levels that are substantial on an international scale. Oil sands production has become increasingly controversial because of several widely publicized environmental and health issues. These features have drawn the attention of local, national, and international media and environmental groups. For example, a recent article in *National Geographic* (Kunzig 2009) has brought oil sands development to the attention of an international audience. A number of environmental activists have highlighted concerns about the environmental and health impacts of oil sands development by advocating consumer boycotts[1] and avoidance of oil sands products by foreign governments.[2]

The debate of the merits and risks of oil sands development among critics, the industry, and the Government of Alberta has become increasingly strident. Canadians are left with a dilemma to determine what is accurate versus what is rhetoric in support of widely divergent positions on the issues. This report seeks to provide an independent review to assess available evidence bearing on the issues and identify knowledge gaps to provide Canadians with a scientific perspective that is not motivated by any of the advocates in the current debate.

By most measures and along many dimensions, Alberta's oil sands deposits are huge (Figure 1.1). When considered as a whole, for example, these deposits are currently estimated to contain more crude oil reserves than are to be found in any country in the world, except for Saudi Arabia. Alberta's Energy Resources Conservation Board (ERCB) (2010, Table 2.1, p. 2-2) considers that there are some 27 billion m^3 (170 billion bbl) of crude oil reserves in Alberta's oil sands. Remaining reserves in Saudi Arabia are estimated at 42 billion m^3, with the next largest endowment being that found in Iran at approximately 22 billion m^3 (BP 2009, p. 6).

The reserve estimates, however, do not tell the entire story of future production possibilities. The ERCB estimates remaining volumes-in-place to be about 270 billion m^3 (1.7 *trillion* bbl).[3] The currently expected average recovery rate of 10% (reserves of 27 billion m^3 and volumes-in-place of 270 billion m^3) is much lower than the 25% or so expected to be realized from Alberta's conventional oil deposits (ERCB 2010, Table 3.4, p. 3-7), with the latter being much more in line with international experience. Given that oil sands production over the last four decades has been characterized by continuous improvements in technology, it would seem reasonable to expect (ACR 2004) that

[1] "Stop Canada's Tar Sands: The Most Destructive Project on Earth"; http://www.lush.com/shop/tarsands

[2] David Suzuki Foundation, Environmental Defence Canada, Forest Ethics, Greenpeace Canada, Natural Resources Defense Council, Pembina Institute, Sierra Club of Canada. (2009). Open Letter to President-Elect Barack Obama. 13 January.

[3] Volumes-in-place is a measure of the remaining "molecules" of oil (bitumen) in the formations; in contrast to reserves, these molecules of bitumen are not necessarily commercially viable to produce under current technologies and present and anticipated economic conditions, For more information on the specific definitions used by Alberta's Energy Resources Conservation Board, see ERCB (2010, Appendix A).

extraction technologies would continue to improve over time, thus allowing even more of the bitumen volumes-in-place to be extracted in a commercially viable way at any given price level. The ultimate production potential of Alberta's oil sands is thus even larger than recent reserve estimates would suggest.

Figure 1.1 Alberta's oil sands areas

Source: ERCB 2009, Figure 2.1, p. 2-1

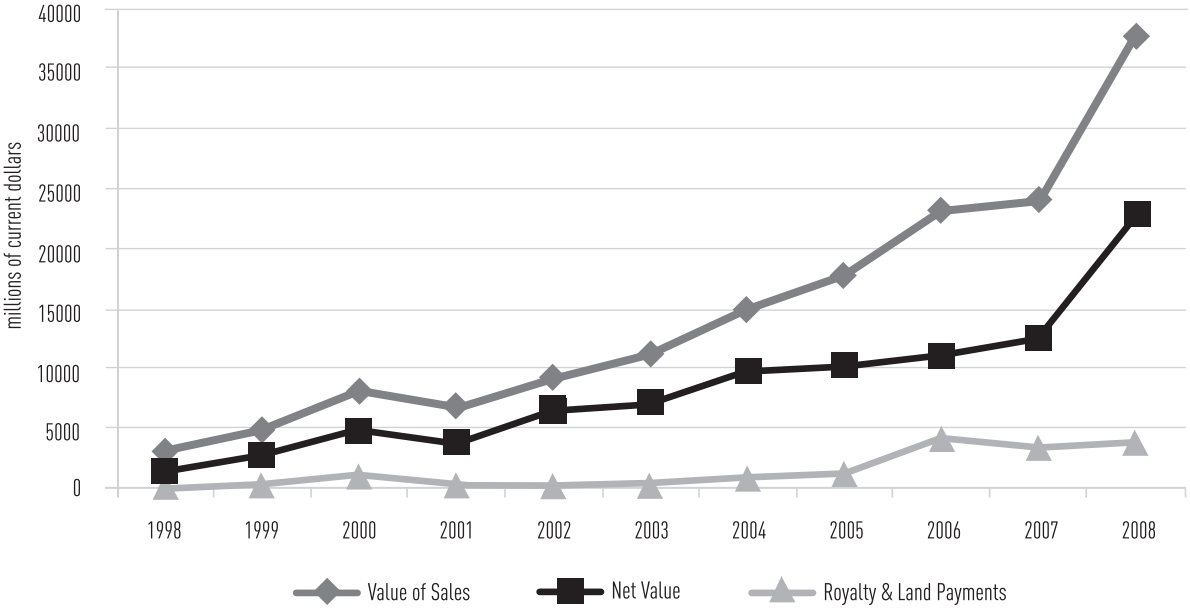
However abundant, these reserves rank among the world's costliest to develop and produce. McColl et al. (2009, Table 3.1, p. 10), for example, estimate that an initial investment of more than $8 billion (at 2009 prices) would be necessary to build a facility capable of producing 16,000 m^3 (100,000 bbl) of crude oil per day. The same amount would have to be spent again to achieve the necessary replacement of the physical capital over the life of the plant. In addition, expenditures needed to sustain operations over this period are thought to be potentially as large as the *sum* of the two types of capital expenditures. Annual expenditure flows reaching into the tens of billions of dollars, sustained over most of the next two decades, would thus be needed to support the kind of oil sands production expansion associated with the forecasts to 2020 estimated for this review (described in detail in Section 2.2).

Capital investment in oil sands projects has accelerated at a remarkable rate since the mid-1990s. In 1996, for example, annual investment spending exceeded $1 billion for the first time, and then quadrupled in less than five years, reaching $4.2 billion in 2000. This rapid growth in investment was sustained over the last decade, to an average of over $16 billion per year from 2006 to 2008 (Appendix A1). Capital investments in oil production capacity are inevitably driven by projected demand for oil.

In North America, about two thirds of oil demand currently arises from the transportation sector and this proportion is projected to increase in the future (IEA 2008, Table 3.2, p. 99).

Despite these enormous expenditures, the net impacts of oil sands development on standard macroeconomic measures (such as Gross Domestic Product (GDP), employment, government revenues, etc.) are estimated to be large and positive. For example, the Oil Sands Developers Group (2009, p. 2) indicates that direct employment in oil sands operations in the Fort McMurray area alone doubled between 1998 and 2008, rising from 6,000 to 12,000, with a further 3,000 new operations jobs expected to be created in 2009 and 2010. Direct employment effects are even larger when jobs related to construction and maintenance of facilities are taken into consideration. During the same period, the value of bitumen and synthetic crude oil sales, measured in current dollars, increased twelvefold, rising from $3.1 billion to $37.8 billion (Figure 1.2). The value of sales net of operating expenditures, royalties, and land acquisition costs ("Net Value" in Figure 1.1) rose even more sharply, from $1.3 billion in 1998 to $22.8 billion in 2008, an increase of 1650%. Oil sands operations are an important source of revenues for the Government of Alberta: in 2008, for example, royalty and land-related payments reached $3.8 billion; between 1998 and 2008, these payments by oil sands developers to the Government of Alberta totalled approximately $15.7 billion.

Figure 1.2 Oil sands revenues: selected measures, 1998–2008



Sources:

"*Value of Sales*": Canadian Association of Petroleum Producers (CAPP) *Statistical Handbook*, Table 04-19B;
"*Net Value*": calculated as "Value of Sales" minus (Operating Expenditures, Royalties, and Bonus Payments) – "Operating Expenditures" and "Royalties" taken from CAPP *Statistical Handbook*, Table 04-16B; "Bonus Payments" from Alberta Department of Energy *Oil Sands Public Offerings Statistics*;
"*Royalty & Land Payments*": calculated as the sum of "Royalties" and "Bonus Payments."

The types of positive net impacts of oil sands development documented above were anticipated before the surge in activity of the last dozen years or so. More than fifteen years ago, the Governments of Alberta and Canada—together with industry representation— assembled the National Oil Sands Task Force (NOSTF) to assess the potential for and macroeconomic implications of expanded oil sands production. NOSTF (1995) provides an early assessment of some of the consequences of developing Alberta's oil sands deposits. While the largest share of the net macroeconomic impacts are estimated to occur in Alberta, the results reported in NOSTF (1995) show that positive economic impacts would also be experienced in every other Canadian province (especially Ontario) and outside Canada since much of the equipment needed by oil sands production plants would be manufactured outside Alberta. More recent studies suggest that these anticipated patterns of effects have unfolded much along the same lines as those predicted in 1995.

Over the last few years, the Canadian Energy Research Institute (CERI) has completed a number of studies dealing with the macroeconomic impacts of oil sands production. Timilsina et al. (2005) use a different approach to that adopted in NOSTF (1995),[4] but nonetheless find broadly consistent results. They show that expanded oil sands production in Alberta can be expected to have net positive effects on a standard set of macroeconomic variables, not only in that province but right across Canada. Of course, the effects are estimated to be concentrated in Alberta (with about 70% of the GDP increases and 55% of the employment growth, for example), but the positive changes are noteworthy in a number of other provinces. Certainly this is the case for Ontario, where about 11% of the rise in GDP and some 16% of the employment boost are estimated to be realized. Estimated effects are smaller in other provinces. Take the case of Québec, for example, where the shares of the GDP and employment increases associated with oil sands development are identified as 1% and 2%, respectively.[5] Overall, Canadians from coast to coast to coast, it is argued, stand to benefit economically from increased activity levels in Alberta's oil sands. More recently, CERI (2009a; 2009b, section 4.5), among others, have updated and extended the work of Timilsina et al. (2005) and again found that expanded oil sands production in Alberta has the potential to yield positive net macroeconomic impacts in Alberta, other Canadian provinces, and (to a lesser degree) in a number of U.S. states. These studies, however, do not explicitly identify and consider the costs associated with the environmental and health-related impacts of oil sands development and production—costs that will be borne by society as a whole and not just by buyers and sellers of oil sands products.

All of this, in turn, brings us to the present review. Various sources have clearly established that Alberta's oil sands hold enormous reserves of crude oil, and these reserves can be tapped using existing technologies and produced in a commercially viable way at currently prevailing prices. If undertaken, these activities—while requiring huge expenditure flows—would generate positive net macroeconomic impacts in Alberta, elsewhere in Canada, and internationally. What we have not yet developed, however, is a comparably clear understanding of the environmental and health-related

[4] Timilsina et al. (2005) draw on CERI's multi-regional input-output model, in contrast to the NOSTF's use of a macroeconometric model.
[5] The distribution of GDP and employment impacts are based on results reported in Timilsina et al. (2005, Table 6.1, p.66; and Table 6.3, p.70), respectively.

impacts of expanded oil sands production. These are precisely the aspects on which this review is focused.

While considerable work on the environmental and health-related impacts of oil sands production has been done, it has yet to be assembled in one document, with a view to analyzing the existing knowledge base and identifying key gaps therein. Similarly, the public policy implications of environmental and health effects of oil sands operations have yet to be considered in a comprehensive manner. Perhaps most importantly, available overview documents on these topics have typically engaged in advocacy of positions rather than a primary commitment to providing an independent review and summary of available evidence. Through this review, we seek to address these gaps.

One major issue which we are explicitly not attempting to address is the overall question of climate change and the role of human activity in driving such change. Our panel has taken it as a given that greenhouse gas (GHG) emissions are an extremely important environmental issue which has justified international, national, regional, and local efforts to reduce GHG emissions. For this review, we focus only on the contribution of the oil sands industry to our collective GHG emissions, the sources of those emissions and control options for reducing them, whether these emissions are increasing, and what implications oil sands GHG emissions may have on Canada's ability to meet our international commitments to reduce GHG emissions.

Given the intense and increasingly strident public debates which have arisen over oil sands and the scale of this development, a number of claims have been made by advocates for and against the industry. Our report reviews the evidence we have found for various key elements bearing on possible environmental and public health impacts, and concludes by summarizing our findings by addressing the following 12 questions that are heard in the current public discourse.

1. Can technology solve all of the environmental challenges of oil sands development?
2. Is in situ bitumen recovery any more environmentally benign than surface mining technology recognizing that in situ will be the major source of bitumen production in the future?
3. Does oil sands water use and pollution threaten the viability of the Athabasca River system and downstream waters?
4. Does oils sands development threaten regional groundwater resources or pose a threat to transfer process contaminants to surface waters?
5. Will all disturbed land ultimately be restored to a natural state by oil sands developers?
6. Are traditional Aboriginal land uses adequately recognized in authorizing oil sands development activities?
7. Is financial security for oil sands disturbed land reclamation adequate?
8. Does oil sands development cause serious human health effects in regional communities?

9. Are cumulative human and environmental impacts of oil sands development being adequately managed (include monitoring and data access) by the current regulatory system?

10. Is the oil sands industry collectively Canada's largest emitter for air pollutants other than greenhouse gases?

11. Are greenhouse gas emissions from the oil sands industry being adequately controlled?

12. Is the oil sands industry the most environmentally destructive project on earth, as has been suggested by some media and declared critics of the industry?

1.2 Scope

Development of the oil sands of northern Alberta has become an issue of growing public interest in recent years, with highly polarized views being presented by different stakeholders including First Nations, environmentalists, industries, and governments, about the merits of this development compared with its environmental and health impacts. Regardless of what any individual chooses to believe about these divergent views, the scale of investment and development in the oil sands is an important factor in Canada's economy, making the issues involved of vital importance to Canadians. The *RSC – The Academies of Arts, Humanities and Sciences of Canada* has assembled a panel of experts that is independent of the major stakeholders to review and assess available evidence bearing on these issues and identify knowledge gaps to provide Canadians with a scientific perspective in a summary report.

This review was undertaken by the panel to assess the issues outlined in the scope and terms of reference at an appropriate high level. In a number of cases, more detail was pursued to illustrate some of the complexities and subtleties that are involved. In other cases, our review focused on what we deemed to be the most critical factors and evidence available to us. The panel acknowledges that the sheer mass of information that was available precluded a comprehensive review of everything potentially relevant. The panel had to exercise its judgement to review and rely upon those sources which offered the most relevant and credible evidence for our task. We also recognized the importance of completing this undertaking in a timely manner. Therefore, despite a continuing onslaught of new information, we have made our best effort to present what we judge to be an accurate assessment of the issues based on the most credible evidence available to us until early December 2010.

1.3 Terms of Reference

The Terms of Reference for this Expert Panel were to address the following questions:

What are the major concerns (for example, risks, risk factors) relevant to the next ~20 years, considering cumulative impacts, including:

- industrial processes
- GHGs (including life cycle analyses)
- air quality
- water quality, quantity
- management of residuals and tailings ponds
- land reclamation, land management
- biodiversity and ecological integrity (aquatic and terrestrial systems)
- human health
- economics and liabilities?

What are current practices and regulatory framework (local, First Nations, national, and international) for managing these concerns?

What are attainable objectives, standards, or principles, for appropriate management of these concerns?

What are the current levels of performance (quantitative and qualitative), gaps in performance, and gaps in knowledge?

What are the various options for closing the gaps:

- technologies, present and forecast
- costs
- the range of policy instruments (market-based, regulation, etc.)
- research
- for all of the above, phase-in periods?

2. STUDY METHODS

2.1. Panel Process

The *RSC – The Academies of Arts, Humanities and Sciences of Canada* announced an Expert Panel on Environmental and Health Impacts of Canada's Oil Sands Industry on October 5, 2009 (Appendix A2). The Panel assembled at the University of Alberta in Edmonton on October 28 and 29, 2009. At this meeting, after introductions, the panel was oriented to the RSC Expert Panel Process before reviewing the Terms of Reference, the panel composition, and procedures and approaches to gathering evidence. The topics to be covered were reviewed and initial writing assignments were made. The panel agreed to a tentative timeline for the report, including a venue and date for a second meeting.

The panel sent letters on November 9, 2009, to 58 relevant stakeholders (Appendix A2) requesting assistance in gathering evidence, specifically:

> *"To assure that this Expert Panel has access to the best available evidence, I am asking you or appropriate staff of your organization, to provide, as soon as feasible, but no later than December 31, 2009, copies of any publicly available reports that specifically contain information or scientific evidence that is directly relevant to our review.*
>
> *Our panel is explicitly* ***not*** *seeking any submissions, position statements or other forms of advocacy regarding any of these issues.*"

Stakeholders were asked to advise of any other parties who should receive this request or to refer the request directly to such other parties. A total of 27 responses were received by January 31, 2010. Stakeholders who requested meetings with the panel chair were advised that the panel had decided that because it could not handle the logistics of providing equal access to the panel for all stakeholders, communications with the panel through the Chair would be limited to written or e-mail correspondence.

The submitted information was organized and posted to a secure website for the panel hosting over 2 GB of documents, and weblinks for much more. Panelists also pursued their own individual research strategies to gather additional evidence, sharing additional documents with other panelists as the report drafting process unfolded. We applied our individual and collective judgement to refine the lists of available reference source materials to rely as much as possible on evidence which we found to be credible and defensible.

The panel's evidence analysis and report drafting process continued through a three-and-a-half day panel workshop at the Banff Centre from June 25 to 29, 2010. Working individually and in small groups around common themes, the panel completed their draft report on August 1, 2010. Following initial copy editing, the draft report was finalized in October 2010 and sent for external peer review. Based on comments received from the RSC peer review process and additional recent and relevant evidence received by the panel, final revisions were made until early December with the final report now released completed on December 13, 2010.

2.2 Oil Sands Development Scenario for Review

At its October 2009 meeting, the panel determined that it would be helpful to have some background insight on likely oil sands developments to provide a perspective on the magnitude and character of likely increases in activity in the next decade.

For this purpose, four estimates of future bitumen production from three reference sources were reviewed (ERCB 2009; CAPP 2009; CERI 2009). There are substantial differences in the bitumen production forecasts among the four estimates summarized with the lowest future production predicted by CAPP, assuming only production from plants that are currently operating or are under construction at the low end, to a projection based on recovery in oil prices which is similar to the ERCB projection. The CERI projection, which was based on 2007 data rather than the 2008 data used by the other two sources, predicts a much higher growth scenario as its base case (Table 2.1).

Table 2.1 Comparison of bitumen production (m^3/d) forecasts to 2018–2020

		Source of Prediction			
Source of Bitumen	**Year**	**ERCB (m^3/d)**	**CAPP only operating & in-construction plant production (m^3/d)**	**CAPP growth scenario with oil price recovery (m^3/d)**	**CERI (m^3/d)**
Surface Mining	2008	115,000	115,000	115,000	143,000
	2018	259,000	188,000	220,000	445,000
	2020	no estimate	188,000	241,000	413,000
In Situ	2008	93,000	93,000	93,000	95,000
	2018	221,000	148,000	226,000	255,000
	2020	no estimate	150,000	255,000	318,000
Total Bitumen	2008	208,000	208,000	208,000	238,000
	2018	470,000	336,000	446,000	700,000
	2020	no estimate	338,000	496,000	731,000

Sources: ERCB 2009; CAPP 2009; CERI 2009c

A few generalizations in forecasting to 2020 are appropriate, despite the numerical differences in the bitumen production predictions:

1. The CERI prediction was made before the 2008 recession and, even taking that into account it is more bullish on bitumen production than either the regulator (ERCB) or the industry (CAPP), with or without an oil price recovery.

2. Surface mining production of bitumen is likely to double over production in 2008.

3. In situ production of bitumen is likely to increase by 2.5–3-fold to become approximately 50% of total bitumen production.

The differences between projections for 2018 and 2020 are negligible compared with the overall uncertainty, so that the 2018 data can be treated as applying to 2020. Updated data (2009) and forecasts were released in June 2010 (ERCB 2010) reporting that in 2009 Alberta produced 47.9 million m^3 (302 million bbl) from the mineable area and 38.5 million m^3 (242 million bbl) from the in situ area, combining to a total bitumen production of 86.4 million m^3 (544 million bbl). This is equivalent to 236,700 m^3/d (1.49 million bbl/d) of bitumen. ERCB extended their forecast to 2019 as reaching 526,000 m^3 (3.3 million barrels) per day by 2019.

Projections for synthetic crude oil (SCO) production are provided in Table 2.2. These data were updated by ERCB (2010) to forecast SCO production in 2019 as 78.5 million m^3 (494 million barrels) or about 91% of total bitumen production in 2019.

Table 2.2 Projected SCO (upgraded bitumen), no projection for 2020

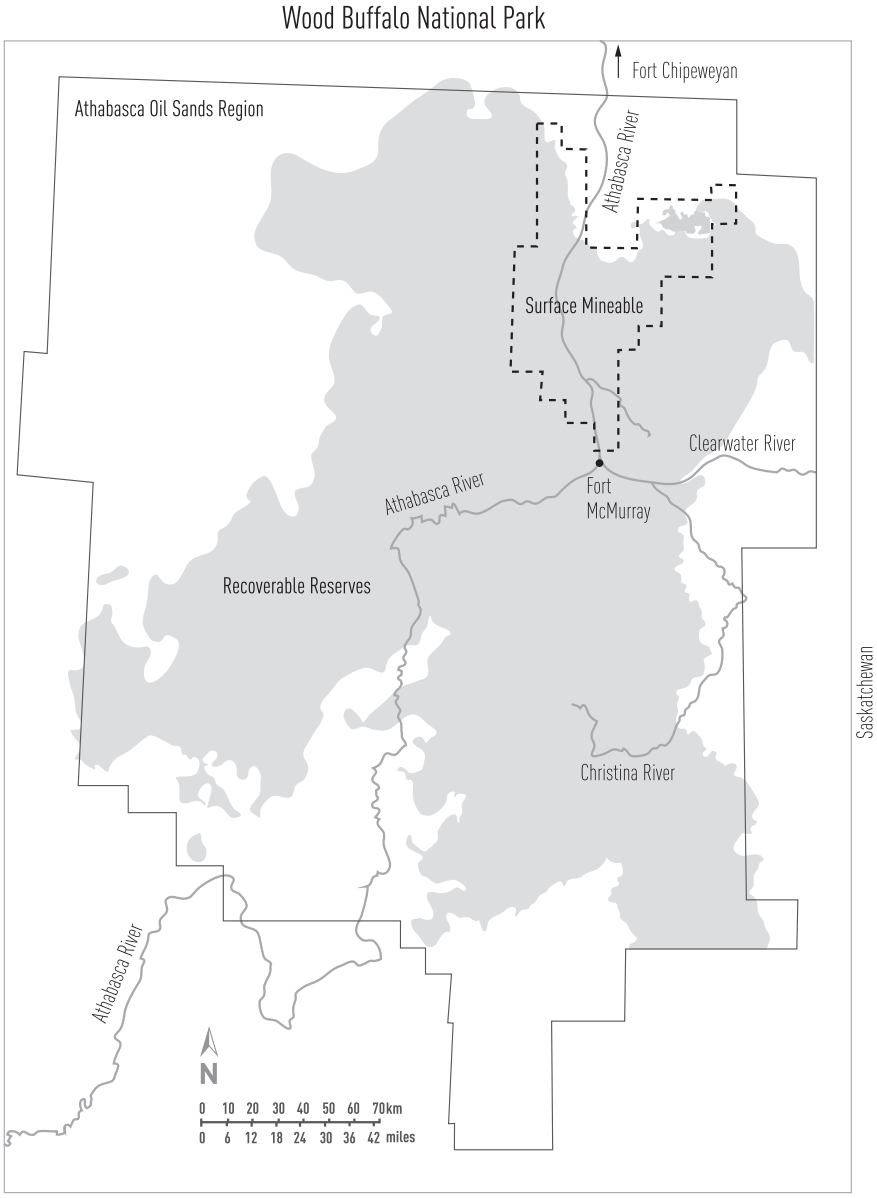
Region	**Project**	**2008 (m^3/d)**	**2018 (m^3/d)**
Athabasca Deposit	Suncor	36,800	
	Syncrude	46,600	
	Shell	20,500	
	Total Athabasca	103,900	151,000
Industrial Heartland			
	Total Industrial Heartland	–	94,000
Alberta	**TOTAL Synthetic Crude Oil**	103,900	245,000

Source: ERCB 2009

Analysis of the ERCB (2009) projections of recoverable reserves and information on the locations and characteristics of bitumen reserves provides some very broad perspective on where and what type of various developments are likely to occur. Only the Athabasca deposit is subject to bitumen recovery by surface mining. Suncor and Syncrude, the two longest operating oil sands plants (43 and 32 years respectively) have substantially more than half (64% and 72% respectively) of their established bitumen reserves remaining to be mined. The Suncor and Syncrude total bitumen production to date represents about 10% of the total estimated surface–mineable reserves in the Athabasca deposit. The

combined project area for Suncor and Syncrude is over 40% of the combined project areas of all operating and actively developing surface mining operations. The total established bitumen reserves remaining for the combination of all the operating and under active development oil sands plants account for 68% of the total remaining surface-mineable bitumen reserves in the Athabasca deposit. Clearly, existing surface mining operations will be a major and active feature of the landscape in the Athabasca region for well beyond 2020, but the footprint for major expansion beyond the currently operating and developing surface mining operations has established boundaries (dashed outline near top of Figure 2.1).

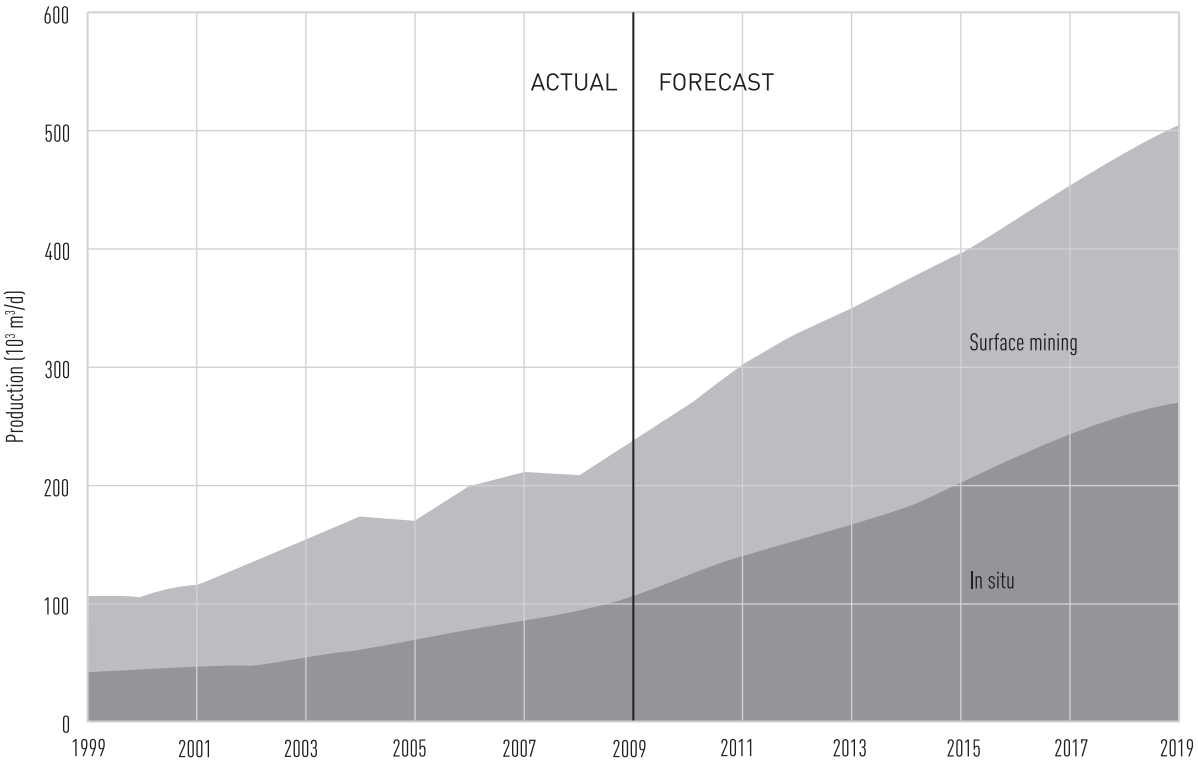
Figure 2.1 The Athabasca Wabiskaw-McMurray oil sands deposit showing the limits of the surface–mineable reserves



Source: ERCB 2010, Figure 2.3, p.2-6

Currently active in situ developments are approaching having produced 40% of their estimated initial reserves, but those remaining reserves that are currently under development represent less than 3% of the total estimated in situ reserves considered recoverable with current technology. Accordingly, there is much greater scope for major expansion in bitumen production by in situ technology than surface mining because of the much larger total reserves recoverable by in situ technology, leading to expectations that in situ bitumen production will catch up with and overtake that from surface mining (Figure 2.2). The introduction of steam assisted gravity drainage (SAGD) in 2002 has coincided with a major increase in commercial production of bitumen from in situ deposits (see Section 4.3).

Figure 2.2 Projected crude bitumen production by surface mining and in situ technology



Source: ERCB 2010, Figure 2.16, p. 2.24

Regarding SCO, at present, all mined bitumen is upgraded, but only a small portion of in situ production is upgraded. SCO production is likely to increase by about 2.5-fold to 2020, with improved economic conditions supporting even higher growth in bitumen upgrading (the ERCB 10-year forecast to 2017 made in 2007 was for a 3-fold increase in upgrading). This was lowered in 2008 because of the number of planned upgrading projects that were withdrawn or suspended.

Table 2.3 Mineable crude bitumen reserves in areas under active development as of December 31, 2008

Development	Project area[a] (ha)	Initial established reserves ($10^6 m^3$)	Cumulative production ($10^6 m^3$)	Remaining established reserves ($10^6 m^3$)	Remaining / Initial established reserve (%)
Operating (as of 2009)					
Shell Albian Sands Shell, Chevron, Marathon	13,581	419	49	371	88%
Horizon[b] Canadian Natural Resources	28,482	537	0	537	100%
Suncor	19,155	687	250	437	64%
Syncrude Canadian Oil Sands ConocoPhillips Imperial Oil, Mocal, Murphy Oil, Nexen, Petro-Canada (Suncor)	44,037	1 306	371	935	72%
Subtotal	***95,255***	***2,949***	***670***	***2,280***	***77%***
Under Active Development					
Fort Hills Petro-Canada (Suncor)	18,976	364	0	364	100%
Kearl Imperial Oil, Exxon Mobil	19,674	872	0	872	100%
Jackpine Shell, Chevron, Western Oil Sands	7,958	222	0	222	100%
TOTAL ***(operating & under active development)***	***151,863***	***4,407***	***670***	***3,738***	***85%***
TOTAL ***(surface–mineable bitumen reserves)***		***6,160***	***670***	***5,490***	***89%***
Total operating & under active development reserves remaining / Total remaining surface-mineable bitumen reserves (%)					***68%***

[a]The project areas correspond to the areas defined in the project approval
[b]Horizon (CNRL) began production in early 2009, so production to Dec 31, 2008, was zero

Source: Adapted from ERCB 2010, Table 2.4, p. 2.15

Table 2.4 In situ crude bitumen reserves in areas under active development as of December 31, 2008

Development	Initial established reserves ($10^6 m^3$)	Cumulative production ($10^6 m^3$)	Remaining established reserves ($10^6 m^3$)	Remaining / initial established reserves (%)
Peace River Oil Sands Area				
Thermal commercial projects	22.3	10	12.3	
Primary recovery schemes	8.0	6.1	1.9	
Subtotal	***30.4***	***16.1***	***14.3***	***47%***
Athabasca Oil Sands Area				
Thermal commercial projects	156.9	36.9	120	
Primary recovery schemes	51.3	20.4	30.9	
Enhanced recovery schemes	28.9	10.3	18.6	
Subtotal	***237.1***	***67.6***	***169.5***	***71%***
Cold Lake Oil Sands Area				
Thermal commercial projects (CCS)	303.2	184.8	118.4	
Thermal commercial projects (SAGD)	16.9	1.0	15.9	
Primary production within projects	30.1	13.7	16.4	
Primary recovery schemes	217.4	52.7	164.7	
Lindbergh primary production	65.5	7.3	58.2	
Subtotal	***633.0***	***259.5***	***373.5***	***59%***
Experimental schemes (all areas)				
Active	1.2	1.1	0.1	
Terminated	9.1	5.8	3.3	
Subtotal	***10.3***	***6.9***	***3.5***	***34%***
TOTAL ***(under active development)***	***908.7***	***350.1***	***560.7***	***62%***
TOTAL ***(in situ recoverable bitumen reserves)***	***21,930***[a]	***350.1***	***21 580***	***98%***
Total remaining bitumen reserves under active development / Total remaining in situ-recoverable bitumen reserves (%)				***2.6%***

[a] This number was calculated by adding the next column (350.1) to the column to the right (21 580) because the number of total in situ established reserves on p. 2–13 of the ERCB report was clearly not correct.

Source: Adapted from ERCB 2010, Table 2.5, p. 2.17

3. HISTORY AND ENVIROMENTAL CONTEXT OF OIL SANDS

3.1 Brief Development History of the Oil Sands

An informative summary of the history of the oil sands has been compiled by the National Energy Board (NEB 2000) and a more detailed account was prepared by Paul Chastko (2004). The history that follows has been drawn primarily from these sources.

3.1.1 Pre-Commercial History

The First Nations of the northern boreal forest had for centuries apparently used bitumen exposed along the banks of rivers in the Athabasca region to patch canoes. The first recorded mention of bitumen is attributed to English explorer Henry Kelsey who was serving as Hudson's Bay Company manager at York Factory in 1719 when a Cree Aboriginal gave him a sample "*of that Gum or pitch that flows out of the Banks of the River*." Peter Pond was the first European explorer to visit the Athabasca region in 1778 and he noted the occurrence of bitumen oozing from the ground. In 1789, Alexander Mackenzie wrote about bitumen outcrops that he described as bituminous fountains.

The Canadian Dominion (federal) government purchased Rupert's Land from the Hudson's Bay Company in 1869. Rupert's Land included what became the provinces of Alberta and Saskatchewan in 1905. The Geological Survey of Canada (GSC) took an interest in the potential resources associated with the bitumen of the Athabasca region and drilled a well at Athabasca Landing in 1894 to a depth of 600 m. The anticipated flowing petroleum resource was not found, so a second well was drilled at Pelican Rapids in 1896. When this also failed to strike flowing oil, the project was cancelled, but the uncapped well blew natural gas for 20 years before it was capped in 1918.

Around the turn of the century, Alberta was beginning to have an unprecedented population boom because of the Dominion government's offer of a free section (1 square mile) of land to settlers. As a result of the settlement incentives, Alberta's population swelled from 73,022 to 373,943 between 1901 and 1911.

Despite the Dominion government's assistance with populating Alberta, it did not transfer control over natural resources to the province upon its creation in 1905; thus, the federal Crown retained mineral rights for about 95% of Alberta, including the Athabasca oil sands deposit. However, having the rights did not equate with having the capacity to develop the resource, so the Dominion Land Agent's office began selling petroleum and natural gas leases for a $5 application fee and first-year rent of $0.25 per acre sparking a black gold rush of hundreds of promoters who raised money from private investors, but fewer than 10% did any drilling. In 1910, one promoter was alleged to have defrauded the federal government into granting exploration rights to 4,615 ha in the Athabasca oil sands deposit (Comfort 1980, as cited in Chastko 2004).

Although the federal government had largely ceded responsibility for development of the oil sands to the private sector, the first president of the University of Alberta, Dr. Henry Marshall Tory, took a personal interest in promoting research into oil sands development for the public good. In 1913, the Alberta MLA Jean L. Côté, wrote to the federal government in Ottawa to ask about plans for

developing the oil in northern Alberta. The federal Department of Mines recognized that it had little detailed information on the Athabasca oil sands, so it formed an investigation team, including Sidney Ells, who travelled to Fort McMurray in 1913 to begin a career-long interest in the topic. By the end of the 1913 field season, Ells had concluded that there was no pool of free oil in these deposits and that bitumen could not be recovered by conventional drilling and pumping methods. He advised the National Parks Branch to create the Horse River Reserve, 232 ha for oil sands research, just south of the original Fort McMurray settlement. An early focus was on using bitumen for paving purposes which included paving trials on Wellington Street and Parliament Hill in Ottawa and the streets of Jasper townsite in Jasper National Park, but despite excellent performance, costs of transport dictated that this was not an economically viable market for bitumen. Max Ball, one of the first entrepreneurs to develop a commercial bitumen extraction operation (the Abasands plant in 1930 described below), credited Ells with preparing the first comprehensive maps of the region and doing the first systematic study of methods for separating bitumen from the oil sands.

Over the next two decades, a story of discord over technology for bitumen extraction emerged between Ells and a junior scientist originally in the same organization, Dr. Karl Clark. While Ells was overseas during the First World War, the director of the Mines Branch engaged Clark and another junior scientist to compile, organize, and review Ells's work on bitumen extraction, which they criticized. In 1920, Clark was recruited to come to the University of Alberta to pursue his recent reports of successfully demonstrating a process for extracting bitumen from oil sands. The focus on oil sands technology became a major focus for the newly created Scientific and Industrial Research Council of Alberta (SIRCA) predecessor to the Alberta Research Council, the first such provincial research agency in Canada. SIRCA was initially housed at the University of Alberta and Dr. Clark was its first research scientist.

3.1.2 Early Small-Scale Commercial History

In 1923, Robert Fitzsimmons purchased a lease at Bitumount (80 km north of Fort McMurray) from a group of New York City policemen who, as the Alcan Oil Company, had failed to produce bitumen by injecting hot water into a well. The Northern Alberta Railway was completed to Fort McMurray in 1926, making it feasible to ship equipment for plant construction to the oil sands region. Fitzsimmons formed the International Bitumen Corporation in 1927, which built the first field bitumen extraction plant using hot water extraction which Fitzsimmons operated commercially until he lost financial control of the operation in 1942.

Meanwhile, Clark was developing and demonstrating the hot water bitumen extraction process between 1922 and 1929. A pilot plant developed in the basement of the power plant at the University of Alberta was scaled up and eventually put into production in the summer of 1930 at a site on the Clearwater River, south of Fort McMurray, where it produced 60 m^3 of bitumen at 90% recovery from the oil sands ore. In 1929, Clark and his associate Sidney Blair were granted a Canadian patent for the hot water separation process.

In 1930, the Natural Resources Transfer Act granted Alberta control over its natural resources but specifically retained for the federal government some 5180 km^2 of leases containing Athabasca oil

sands deposits (about 3.5% of the total oil sands area as known in 2010). Weeks before the resource transfer agreement was due to take effect, and without any consultation with the province, Ottawa announced a lease agreement with an American investor, Max Ball, to develop the oil sands with the creation of Canadian Northern Oil Sands Products (later Abasands Oil Ltd.) which developed a plant on the Horse River.

With the severe financial constraints of the depression, Alberta ceased funding the Alberta Research Council in 1933, a condition that was not reversed until 1942. A glut of cheap oil depressed oil prices and created a squeeze on operating budgets for Abasands Oil, but it managed to stay in business throughout that decade. Despite the slow progress and many setbacks, by the beginning of the Second World War, the oil sands resource was considered to be a feasible energy source. By 1941, Abasand had processed 19,000 tonnes of oil sands producing 2700 m^3 (17,000 bbl) of bitumen which it converted into a variety of petroleum products including gasoline, before it suffered a fire in 1941. Abasands was rebuilt in 1942 and was taken over by the federal government in 1943 under the War Measures Act. The plant was burned to the ground by a catastrophic fire in June 1945. The Abasands failure became a major source of conflict between the provincial and federal governments, with the former believing that this development had become a fiasco caused by incompetence and neglect by federal bureaucrats. Alberta saw the Abasands failure as a major setback in acquiring tangible commercial interest in developing the oil sands and determined to take the lead from the federal government in developing a case for oil sands production.

In 1948, the former International Bitumen Corporation plant at Bitumount was acquired by the Government of Alberta to use as an experimental facility. In 1949, the plant was processing 450 tonnes of oil sand a day but the government did not wish to develop a commercial operation, preferring this to be done by the private sector, so this plant was shut down.

Some of these early patterns of activity would foreshadow subsequent aspects of oil sands development, including: severe tension between the federal and provincial governments, lack of a clear policy regarding the private sector role, and a roller coaster ride of commercial interest in development driven by fluctuating oil prices. A major discovery of light crude oil at Leduc in 1947 transformed Alberta into a substantial conventional oil producer which, once again, made oil sands development look less attractive and less likely to be important as a major source of oil production.

3.1.3 Full-Scale Commercial History

The 1950 Blair report commissioned by the Alberta government used data from the Bitumount plant to show that oil sands development could be economically feasible if done on a scale of at least 3,200 m^3/d (20,000 bbl/d), leading to a dozen oil companies purchasing three-year exploration agreements of 20,230 ha each. However, companies found too risky the requirements; while they could acquire a lease if they found hydrocarbons of interest, they would have to proceed with a commercial plant within a year to retain the lease. The rules were modified to introduce provincial government discretion on this requirement which led to the first major commercial acquisition of oil sands leases.

A bizarre proposal for recovering oil from the oil sands arose in 1958 when the Richfield Oil Corporation proposed “Project Cauldron” which involved detonating a 9 kt nuclear explosion underground in the oil sands to liquefy buried bitumen making an instant oil field. The proposal received serious consideration at all levels of government and was taken to the U.S. Atomic Energy Commission which approved the idea. Testing was performed in Nevada before the idea was shelved by the Canadian authorities.

Sun Oil was an early lease-holder and it undertook extensive exploration in the 1950s, leading to the development of Great Canadian Oil Sands (GCOS), the first major commercial operation, which began operations in 1967. This commitment came about because John Howard Pew, founder of Sun Oil, had a vision that the oil sands represented a petroleum resource of the future. Pew had established a personal relationship of trust with the Premier of Alberta, Ernest Manning, who saw a need to develop the oil sands but believed that major investments like this should come from the private sector.

Ironically, while the Manning government wished to see the oil sands developed, the first GCOS application for approval to build a commercial oil sands plant producing 5000 m^3/d (31,500 bbl/d) in 1960, was turned down by the Alberta Oil and Gas Conservation Board (OGCB, predecessor of the ERCB). The negative decision was based partly on OGCB concerns about economic feasibility but mainly about the impact of SCO production on the oil market for Alberta’s conventional crude oil (CCO) which was already being limited by market demand. Alberta crude was more expensive than off-shore oil imports so that 40% of Canada’s market in eastern Canada was not buying Alberta oil and the U.S. maintained import quotas on Canadian oil. However, the OGCB encouraged GCOS to resubmit an application before June 30, 1962. GCOS resubmitted its application in March 1962, amid musings from the Premier that because of the market squeeze for Alberta’s conventional oil, SCO production might have to be delayed until 1975.

The OGCB recommended the GCOS application which was approved by the Government of Alberta in October 1962. With this decision, Alberta introduced an oil sands policy seeking to encourage orderly development of the oil sands to supplement (to a maximum of 5% of Alberta’s total production), but not replace conventional oil production, which was already a major driver of the Alberta economy and a major royalty revenue source for the Alberta government. This production limit for oil sands effectively made GCOS the chosen instrument for implementing Alberta oil sands policy. Competing applications to the OGCB by Cities Service and Shell Oil, each for 16,000 m^3/d (100,000 bbl/d) operations were thus undermined.

Although both companies persisted with their applications, the OGCB turned them both down on the grounds that their production could not be accommodated within the 5% quota for oil sands which was now government policy. The 1962 Alberta oil sands policy also involved a substantially higher royalty regime than GCOS had used in its application to the OGCB. This royalty increase proved sufficient to drive two financial partners in GCOS, Canadian Pacific and Shell, out of the consortium, which would have collapsed if Sun Oil Corporation had not agreed to pick up those shares. Sun Oil did so on the condition that GCOS be designed to produce 7150 m^3/d (45,000 bbl/d), which required an amended application to the OGCB, because this level would correspond to 7.5% of Alberta’s total production, exceeding the government policy which had been cited in declining the applications from Cities

Service and Shell Oil. In 1964, the OGCB approved the amended application, presumably as the lesser of two evils because the collapse of GCOS would leave the only prospects for an oil sands plant ones which had been requesting a much higher, 16,000 m^3/d (100,000 bbl/d) capacity (17% of total Alberta production).

GCOS began operations in September 1967 with a capacity of 7150 m^3/d (45,000 bbl/d), but it would produce only 2400 m^3/d (15,000 bbl/d) in 1968 because of technical difficulties. GCOS was not able to produce at the approved capacity until 1972. Allowable production was increased to 10,300 m^3/d (65,000 bbl/d) in 1974, but annual average production remained below 7150 m^3/d (45,000 bbl/d) through 1978. Sun Oil had provided 99% of the original $240 million investment in the GCOS project which was ~75% of Canada's investment in the St. Lawrence Seaway (Johnson 1983). Suncor states that this was the largest single private investment in Canada to that time (Suncor 2010). The project continued to lose money into 1970 and GCOS was able to convince the Government of Alberta to cut its royalty rate in half from 16% to 8% in May 1970.

Meanwhile, Syncrude Canada Ltd. (a consortium of Cities Service, Imperial Oil, Royalite, and Atlantic-Richfield) was formed in 1964 to undertake research on the technical and economic feasibility of oil sands operations at a commercial scale. The quota allowed for oil sands continued to be an issue constraining any further oil sands development. The Alberta government ultimately modifed its oil sands policy in 1968, implicitly acknowledging that oil sands development had been constrained by government policy rather than unwillingness of the oil industry to invest in projects. The revised policy accommodated up to 24,000 m^3/d (150,000 bbl/d) of oil sands production, allowing Syncrude to resurrect the 1962 Cities Service application in 1968, with an amended production capacity of 12,700 m^3/d (80,000 bbl/d). Syncrude's proposal was approved except for its marketing plan and the OGCB asked for additional hearings to address the impact of Alaskan oil from Prudhoe Bay on projected oil sand markets.

Syncrude took the unusual step of appealing directly to the Alberta Cabinet to overturn the OGCB decision, but to the credit of the Alberta government, Cabinet upheld the OGCB decision. After brief hearings only on the marketing plan, the OGCB issued a split decision 2 to 1 to approve the Syncrude application in September 1969. In spite of approval, development did not proceed as expected. Rising costs prompted Syncrude to apply to the OGCB to increase its approved production capacity to 20,000 m^3/d (125,000 bbl/d). U.S. oil production had peaked in 1970 and the U.S. was now increasingly dependent on foreign oil, making the market for Canadian oil more promising. The revised Syncrude proposal was approved in 1971, but critical shortages of skilled labour, equipment, materials, and supplies combined with infrastructure limitations in Fort McMurray posed growing concerns for the viability of this project.

In the meantime, several events dramatically changed the landscape. The Social Credit government which had been in power for 35 years and which was responsible for the key policies that had governed oil sands development to that point was defeated in 1971 by Peter Lougheed's Progressive Conservatives. International events and interventions by the Organization for Petroleum Exporting Countries (OPEC) caused international oil prices to more than triple from 1972 to 1974. This rapidly changing landscape unsettled the Alberta government in its negotiations with Syncrude. Matters were

further complicated by a federal policy to shield Canadians from world oil prices with a federal subsidy paid for by an export tax on Alberta oil exports, removing the deduction of provincial royalties from the industry calculation of federal corporate income tax and other increased taxes on oil companies operating in Canada. This subsidy grew from $4.85 per m^3 ($0.77 per bbl) in 1973 to $127 per m^3 ($20.17 per bbl) in 1980 when world prices reached $225 per m^3 ($35.75 per bbl), a 10-fold increase over 1972.

Sudden concern over the reliability of offshore oil imports to eastern Canada led to a declaration from Prime Minister Trudeau in December 1973 that Canada would develop a national energy policy to achieve energy self-sufficiency by 1980. The Trudeau plan included the creation of Petro-Canada as a national oil company, the construction of an oil pipeline from Ontario to supply Alberta oil to Montreal which was totally reliant on imported oil, a federal commitment of $40 million to oil sands research, and a commitment that Petro-Canada[6] would be active in the oil sands.

Meanwhile, inflationary pressures pushed the estimated capital costs of the Syncrude project from $650 million at the end of 1972 to $1 billion in July 1973. A royalty agreement was not reached with Syncrude until 1973 when Alberta agreed to take 50% of Syncrude's net profits rather than placing a royalty on production as had been required for GCOS. Syncrude construction did not begin until the spring of 1974 and it began operations in 1978.

Although Peter Lougheed was suspicious of the multi-national oil companies and they found him more difficult to deal with than the previous Social Credit government, the growing antagonism between the federal and Alberta governments meant that the oil industry and Lougheed had more in common with each other than either had with the federal government. Throughout the 1970s, there was tension between Premier Lougheed and Prime Minister Trudeau. An exception was an agreement reached in 1975 for joint funding of the Canada-Alberta agreement to establish the Alberta Oil Sands Environmental Research Program (AOSERP) projected to last 10 years with a total budget of $30 to $40 million. There were expectations expressed at that time that more than 10 new oil sands plants might be constructed over the term of the study. There was a further brief thaw in Alberta-Canada relations in 1977 with the establishment of a Joint Task Force to review economic conditions for promoting oil sands investment. By September 1978, the antagonism returned when the federal government backed out of an agreement to raise Canadian oil prices to within $6.30 per m^3 ($1 per bbl) of world prices. At about the same time, the federal government announced that it was backing out of funding for AOSERP effective March 31, 1979. Alberta committed to continue funding the environmental research program until the end of 1980. In retrospect, the opportunity for gaining a meaningful baseline of environmental conditions in the oil sands region was lost with the cancellation of the joint federal-provincial environmental research program.

There had been some migration of oil industry investment away from Alberta during the 1970s because of the uncertainty created by the conflict between the provincial and federal governments. This changed rapidly with the Iranian revolution in 1978 which resulted in world oil prices more than

[6] After its creation in 1974, Petro-Canada began to be privatized in 1990 with the federal government selling its remaining shares in 2004. In 2009 Petro-Canada merged with Suncor to operate under the Suncor Energy name.

doubling, causing oil companies to see Alberta as an attractive stable investment environment. In 1974, there were approximately 300 oil companies operating in Calgary and by 1979, this had risen to over 700, many being smaller firms that were debt-financed. In the late 1970s, there was renewed interest among large oil companies in pursuing major oil sands projects as Shell, Imperial, and Gulf all considered projects. Shell led the Alsands consortium proposing a 21,800 m^3/d (137,000 bbl/d) surface mining plant and Imperial was proposing a 22,250 m^3/d (140,000 bbl/d) in situ oil sands project in Cold Lake.

The Alberta Oil Sands Technology and Research Authority (AOSTRA) was created by the Alberta government in 1974 to work with industry to develop technologies for accessing the majority of oil sands buried too deeply to be mined. AOSTRA can be credited with developing the steam assisted gravity drainage process (SAGD) which is now the primary in situ bitumen extraction process in use.

During the brief period of Joe Clark as Prime Minister, negotiations between Alberta and Ottawa on energy matters did not improve. On February 18, 1980, Pierre Trudeau was returned to power with a majority government, changing the relationship dramatically for the worse with the federal budget of October 28, 1980, and the introduction of the National Energy Program (NEP). This had the immediate effect of driving oil investment out of Alberta and offering incentives to explore for oil on Canada Crown lands. The Toronto Stock Exchange oil and gas index dropped 16% in two days, a decrease of $2.3 billion in investment value. Alberta went overnight from boom to severe recession soon to be followed by the rest of Canada. The federal government had not expected world oil prices to collapse from their peak by slackening demand caused by a worldwide recession in 1982. This recession was particularly severe in Canada as GDP dropped by 6.7% over a period of 18 months. Alberta went from full employment in 1980 to a peak of 11% unemployment in 1984 even allowing for years of migration out of Alberta after the NEP.

Ironically given the current debates in Canada, the NEP intended to achieve the failed target of the previous decade, energy self-sufficiency for Canada, in part by promoting oil sands projects. However, the combination of an unfavourable investment climate in Alberta and collapsed world oil prices led to Imperial Oil putting its Cold Lake project on indefinite hold in July 1981, the Alsands consortium collapsing on April 30, 1982, and Syncrude delaying a major expansion proposal. Activity would remain dormant for at least five years, but heading into the 1988 federal election, the ruling Conservatives promised a $1.7 billion commitment to the Other Six Lease Operators' project (OSLO), the last oil sands mega-project left over from the economic decline of the early 1980s in Alberta. Despite the vigorous support of both federal and provincial governments in the late 1980s, the federal government pulled out of the project in the 1990 budget and by 1992 Alberta had to acknowledge that the mega-project, with its promise of major economic activity, was dead.

This brings this history account to the creation of the NOSTF in 1993 with its landmark report in 1995 that established the modern oil sands investment climate, which is summarized in Section 1.1 and Appendix A1.

3.2 History of Some Major Environmental Incidents

No records have been found for early operations, but an archival photo of the Abasands Plant and its record of fires leading to its eventual destruction suggest that early operations likely had major environmental releases to air and water, tempered primarily by the relatively small scale of these operations. Environmental performance of any industry in Canada, prior to the emergence of industrial environmental controls in the 1970s, was generally poor by current standards and pollution control in remote areas was generally ignored. Environmental regulations were not a major government consideration prior to 1970, with the current environmental regulators Alberta Environment and Environment Canada only having been created in 1971.

The following environmental incidents are recounted because they have a documented public record that was accessible to this panel. Industry responses to these incidents would have been informative but were not available to this panel as part of the public record.

3.2.1 GCOS

The first viable commercial oil sands producer was GCOS and from the beginning it experienced a number of process upsets and associated environmental releases.

A plant failure in November 1967 led to a bitumen spill into wetlands near the upgrading plant flare stack which ultimately reached the Athabasca River, causing complaints of oil on the river in March 1968. Investigation revealed a black layer of oil half a mile downstream from GCOS (Shewchuk 1968). There is no mention of a prosecution being pursued for this incident.

In June 1970, a GCOS pipeline released over 3,000 m^3 (19,000 bbl) of oil that reached the Athabasca River. The oil slick was visible all the way down to the Athabasca Delta 250 km downstream (Hogge et al. 1970). The oil slick persisted for up to two weeks and the water supplies for Fort McKay and Fort Chipewyan and the commercial fishery in the Athabasca Delta were interrupted. Although an interpepartmental and intergovernmental investigation was launched, there is no mention of a prosecution being pursued for this incident. The cost of the provincial government response and investigation was calculated to be $6,338.02 as August 1970.

An Environment Canada surveillance report found that drainage collected from the dyke of the first GCOS (Tar Island) tailings pond that was freely flowing into the Athabasca River was acutely toxic to rainbow trout in a 96-hour static bioassay (Hrudey 1975). According to the current operating permit for GCOS, no process-affected water should have been discharged to the environment.

AENV collected samples at four locations near the tailings pond and the Athabasca River on July 12, 1976: the dyke drainage itself, a discharge from a riverbank pipe, downstream samples and upstream samples in the Athabasca River. Charges were laid under the federal Fisheries Act, although the deposit was also a violation of the permit issued under the Alberta Clean Water Act. In 1977, GCOS was acquitted of these charges and this acquittal was upheld on appeal by the Crown. The prosecution proved that the tailings pond dyke drainage was toxic to rainbow trout and brook stickleback and the discharge was unauthorized. The Provincial Court and the Alberta District Court on appeal, ruled for

numerous reasons that the Crown had not made its case (R. v. GCOS 1978).[7] A review of the reasons stated for the Court's decision strongly suggests that the defence was substantially better prepared and resourced for this trial than was the Crown.

3.2.2 Suncor (formerly GCOS)

A series of equipment failures during December 1981 at the Suncor (formerly GCOS) upgrading plant led to a fire which destroyed the insulation on the pipeline to the coker flare stack. A subsequent process upset in January 1982, during severely cold (-45°C) weather, led to a major fire which required a complete shutdown for months. During the upset that caused the fire, the hydrocarbon contents of a coking unit had been discharged to the flare stack. Some hydrocarbons spilled over into the wastewater pond and some condensed in the pipeline to the flare because of the lack of insulation, resulting in fireballs being emitted from the flare stack which ignited the hydrocarbons on the wastewater pond. The wastewater pond had an enormous fire which threatened to destroy the entire upgrading complex. The wastewater pond normally contained mainly cooling water and was isolated from the Athabasca River by a submerged pipe to preclude any surface oil being discharged to the river. During unusually warm weather in February 1982, Suncor's monitoring detected oil being discharged well above permitted limits and downstream users complained of visible oil and eventually tainted fish in the Athabasca River.

An estimated 50 tonnes of oil was released to the Athabasca River (Birkholz et al. 1987). A trial of Suncor under the Alberta Clean Water Act for permit violations involving excessive emulsified oil discharge through the submerged discharge to the Athabasca River led to an acquittal, reminiscent of

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[7] The appeal judged summarized the evidence as indicating that:

(1) The river itself displayed no evidence of any adverse effects as a result of any aspect of Great Canadian's operation.
(2) There was no evidence of any disruption of the aquatic or biological systems present in the river.
(3) While there was some evidence that sodium hydroxide, naphthenic acid and bitumen itself reached the tailings pond as by-products of the extraction process there was no evidence that they or any harmful substance was discharged from the tailings pond during or after the settling process into the river through the discharge pipes investigated by the environmental authorities. No analysis of the questioned fluids was proven in evidence. An in extremis attempt to prove that ammoniated fertilizer used by the company in the cultivation of grass and shrubbery during area reclamation had washed into the river during recent heavy rains was made by crown counsel during his cross-examination of defence witnesses. The learned Provincial judge made no finding in this regard but it is clear from the reasoning of Regina v. Wynnychuk (1962), 37 W.W.R. (N.S.) 381 that such a finding could not support a verdict adverse to the respondent.
(4) The dyke drainage sample fluid was not proved to have reached the Athabasca River or have been "deposited" within it.
(5) The interface sample fluids, apart from their questionable source, were not proved "deleterious" having regard to the fact that the Athabasca River itself was either inhospitable or instinctively objectionable to Brook Stickleback and Rainbow Trout because of their absence, or at least rarity, in its waters.
(6) No proper evidence was led indicating the chemical composition of the alleged effluents from which the learned Provincial Judge could find toxicity to fish by themselves or in conjuction with other substances.
(7) No proper evidence was led establishing that any toxic substance associated with the company's operation reached the river which was not present in any event when regard is had to the fact that the river or its tributaries flow through outcroppings of tar releasing into its course bitumen iridescents or natural oil slicks.
(8) There was no evidence indicating the pathology of the dead Rainbow Trout and Brook Stickleback.
(9) No tests whatever appear to have been carried out to demonstrate any undesirable effect arising from the alleged effluents upon aquatic life measurably innate to the Athabasca River. Consequently there was no evidence that any species that "frequented" the river was deleteriously affected.

the previous 1977 / 78 acquittals because the defence was much better resourced than the prosecution. These circumstances were remedied for two subsequent trials in the Alberta Provincial Court under the FA which ultimately resulted in in Suncor being found guilty of three counts (for separate discharge days) of depositing a deleterious substance under the FA.

3.2.3 Total EP Canada Ltd.

Total EP Canada Ltd. was operating a SAGD project at Josslyn Creek 60 km northwest of Fort McMurray. On May 18, 2006, it had a massive steam explosion which blew a surface crater 75 x 125 m, ejected rocks up to 300 m horizontally and created a 1-km long dust plume to the southwest after the blast. Fortunately, there were no injuries or off-site environmental damage beyond the distribution of debris and creation of the crater.

Total submitted its 1,140 page Incident Report in December 2007 to the ERCB and finalized it in September 2008 after meeting ERCB requests for additional information. The ERCB released its staff investigation report on February 23, 2010. This investigation, described as the most comprehensive in ERCB history, attributed this steam exposion to Total being in non-compliance with its ERCB operating approval by operating at steam pressures significantly above the 1,400 kPa proposed in its application, failing to implement alarms and automatic shutdowns of any wells exceeding the 1,800 kPa reservoir fracture pressure and exceeding the Directive 051 approved maximum wellhead injection pressure of 1,800 kPa (ERCB 2010).

The ERCB can enforce a variety of penalties for non-compliance, but the penalty with the greatest economic consequences to an operator is to permanently shut an operation down. In this case because the project had been suspended and was being abandoned by Total, the ERCB staff did not recommend any additional penalties. It was not clear from this decision if the ERCB was compensated for the extensive investigation costs it incurred by this major failure of an in situ project.

3.2.4 Syncrude Canada Ltd.

Most recently, Syncrude has been prosecuted under the Alberta Environmental Protection and Enhancement Act (EPEA) and the federal Migratory Birds Convention Act (MBCA) for an incident in late April 2008 when an estimated 1,600 ducks died after landing on the Syncrude Aurora tailings pond and being oiled after contacting floating bitumen.

The case was tried in the spring and summer of 2010, with the judge making a finding of guilty on both charges (EPEA and MBCA) and, based on a negotiated settlement between the prosecution and Syncrude, ordering the largest penalties for an environmental conviction in Canadian history, a total of $2,900,000. More discussion of this incident can be found in Sections 5.5.2 and 5.5.3 and the problem of waterfowl being endangered by tailings ponds is discussed in Section 8.2.2.1.

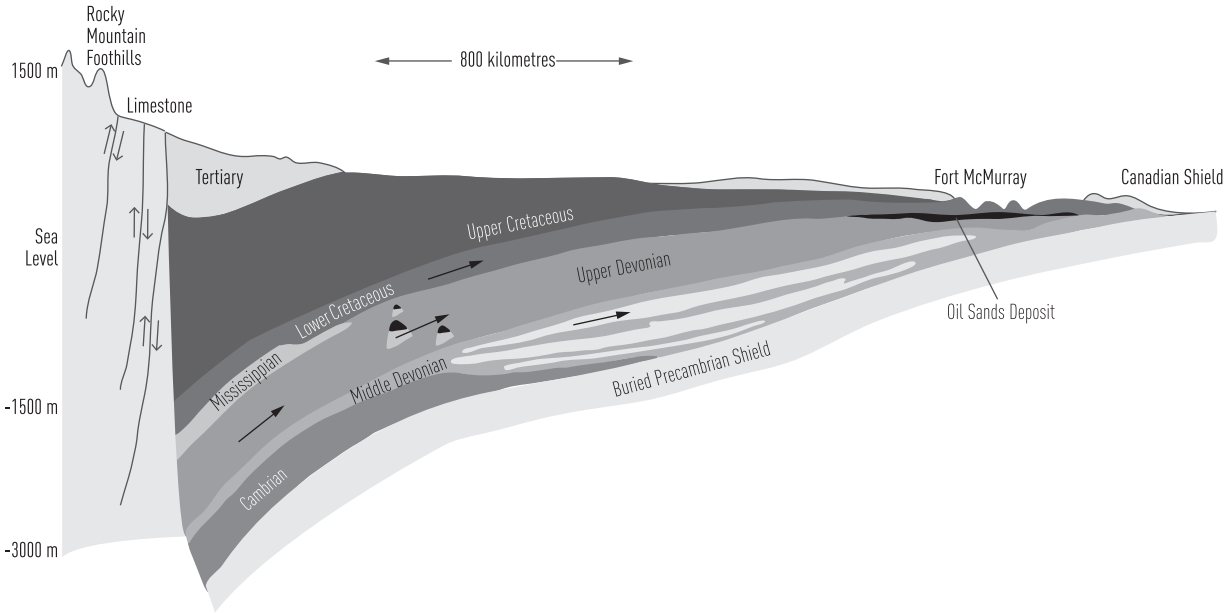
3.3 Physical Environment

Oil sands deposits are located in Alberta in the northern regions of the Western Canada Sedimentary Basin (WCSB) which has held most of Canada’s conventional oil and gas reserves in Alberta, Saskatchewan, and British Columbia. For administrative purposes, the Alberta government has defined

three Oil Sands Areas (OSA): Athabasca, Peace River, and Cold Lake that regroup all of the fifteen individual deposits (Figure 1.1). Together, the OSA cover an area of approximately 142,000 km^2 (ERCB 2010), slightly larger than the area occupied by Canada's three maritime provinces combined and slightly smaller than the U.S. state of Illinois. The Athabasca OSA, in which Fort McMurray is located, is the largest area both for bitumen volumes-in-place and remaining reserves. The McMurray formation of the Wabiskaw-McMurray Deposit is the only region where oil sands deposits in the reaches of the Athabasca River valley are shallow enough (<65 m) for economical surface mining (Figure 1.1, and Figure 4.2 in Section 4.1).

Although there is still some geological uncertainty about the age of the source rocks, light oil is believed to have been sourced in the deeper portions of the WCSB from which it migrated hundreds of km to the present location of the oil sands deposits (Figure 3.2).

Figure 3.2 Oil migration path in the Western Canada Sedimentary Basin to form the oil sands deposits



Source: NEB 2000, Figure 2.2, p.6

According to NEB (2000): "*The McMurray or equivalent sands were the primary collectors of the generated oil and provided the main conduit for migration. It is speculated that the migration path was at least 360 kilometres for the Athabasca Deposit and at least 80 kilometres for the Peace River deposits. These lighter oils were then subjected to biodegradation transforming them into bitumen*."

The microbial action of biodegradation decomposed the lighter hydrocarbons leaving much larger, complex hydrocarbons, heavy minerals (vanadium, nickel, magnetite, gold, silver), and sulphur. The resulting bitumen with its low specific gravity and high viscosity which determine its reservoir properties[8] is largely a product of natural biodegradation. Only about 20% of the ultimately recoverable volume is considered economically recoverable with surface mining, while the remaining

[8] Bitumen will not flow to a conventional oil well without the introduction of heat to reduce its viscosity.

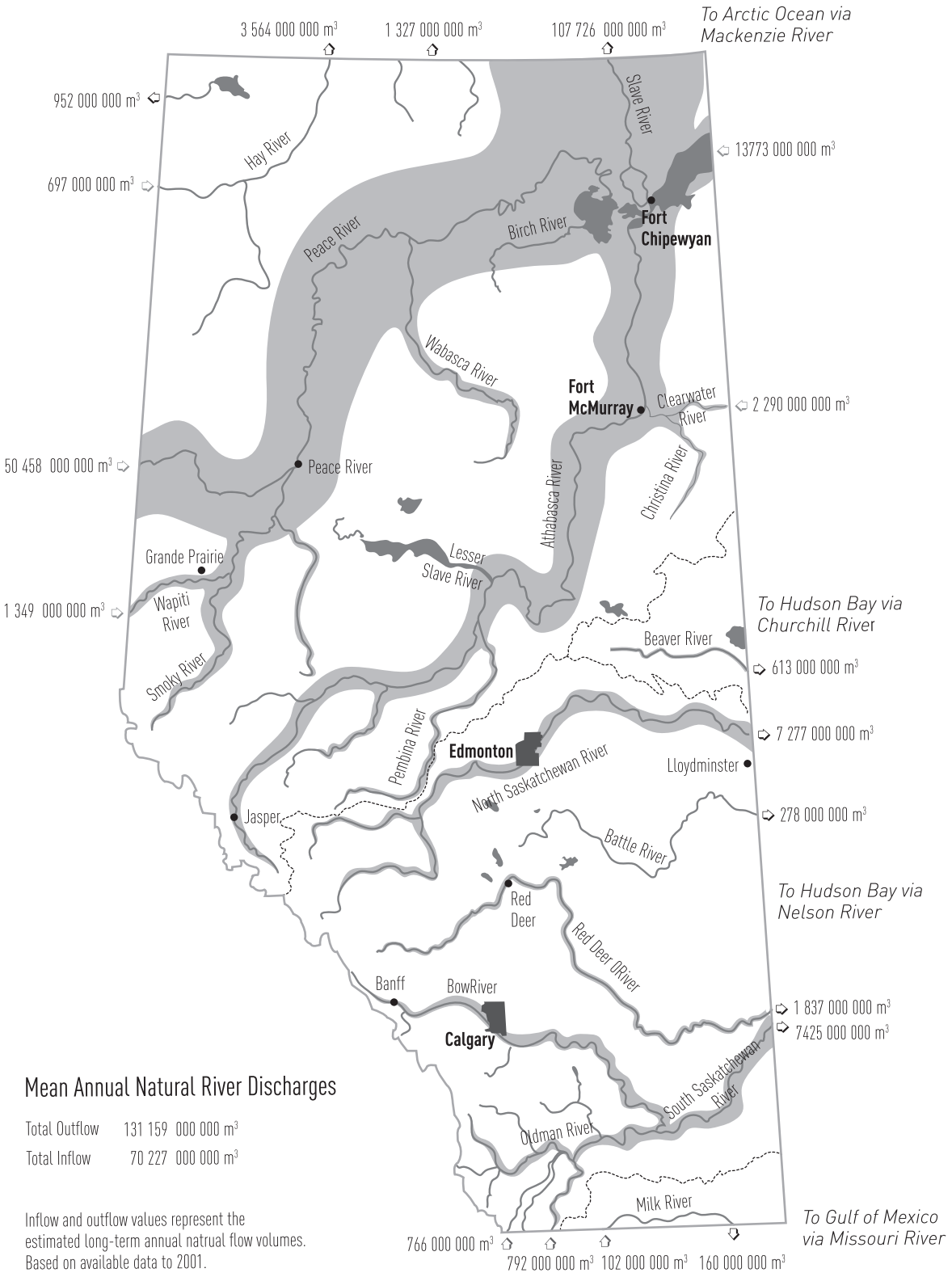
80% will require some form of in situ recovery. Further details on bitumen and the technologies required to recover it are provided in Section 4.

Northern Alberta, where the majority of oil sands development is occurring, is located in Canada's boreal zone, which Brandt (2009) defines as: "*the broad, circumpolar vegetation zone of high northern latitudes covered principally with forests and other wooded land consisting of cold-tolerant trees species primarily within the genera* Abies *[fir],* Larix *[larch],* Picea *[spruce], or* Pinus *[pine] but also* Populus *[poplar] and* Betula *[birch]; the zone also includes lakes, rivers, and wetlands, and naturally treeless areas such as alpine areas on mountains, heathlands in areas influenced by oceanic climatic conditions, and some grasslands in drier areas*."

The boreal forest, which makes up 30% of Canada's total land area, accounts for 77% of Canada's total forest land of four million km^2 which is about 10% of the world's total forest cover (Brandt 2009; NRCan 2008). The boreal forest in northern Alberta consists of broad lowland plains and extensive hill systems. Bedrock is buried deeply beneath glacial deposits and outcrops occur only rarely along major stream valleys. The upland regions have mixed wood stands of aspen poplar and white spruce. Lowland boreal forest or muskeg is dominated by black spruce and tamarack larch. Other typical species include balsam fir, balsam poplar, jack pine, and lodgepole pine. In the northern areas, coniferous cover is commonly broken only by water in the form of fens (mineral-rich wetlands), muskeg (saturated, acidic peatbogs), lakes, and rivers. Most of the region is regulated by Forestry Management Agreements (FMA) which assign timber-harvesting rights to the FMA-holder.

Water is a major feature of Canada's boreal zone, with 540,000 km^2 of surface waters comprising over 60% of Canada's inland water area (Brandt 2009). The large inventory of standing water found in lakes, while impressive, should not be mistaken for a renewable water resource, something which depends more on annual river flows. Northern Alberta features the largest rivers in the province, the Peace and the Athabasca, which flow into the Mackenzie River system to the Arctic Ocean (Figure 3.2). This figure shows the relative magnitude of long-term annual natural flows as the shaded width around each river. The relative magnitude of water flows to the north is evident compared with water-limited southern Alberta. These waters support a wide range of fish species including lake whitefish, goldeye, rocky mountain whitefish, northern pike, burbot, and walleye, with a world-class fishery for the latter.

Figure 3.2 Mean annual discharge of Alberta's rivers



Source: AB Env 2010

The boreal forest is home to half of Canada's 450 bird species and a wide range of mammals, including moose, wolf, caribou, bear, rabbit, lynx, cougar, mink, wolverine, and river otter, many of which are icons of Canada's wilderness heritage viewed from both immigrant and Aboriginal perspectives (NRCan 2010).

The future of this region is subject to uncertainty not only because of the projected oil sands development which is the subject of this report, but also because climate change models predict substantial changes for northern Alberta. In particular, modelling with the Canadian Coupled Global Climate Model 2 predicted the greatest temperature rise and greatest precipitation increase for what were described as the northern and eastern "prairie" zones which include the oil sands region (Sauchyn and Kulshreshtha 2008).

3.4 Human Environment

This region has been the ancestral home to Aboriginal peoples who met European explorers and fur traders in the 1700s. For almost two centuries, the fur trade between Aboriginal peoples of the region and Europeans was the main economic activity of the area. It was not until June 21, 1899, that Treaty 8 between the Indians of North America and the Queen of England was signed. The Treaty 8 First Nations have noted: "*The signatories of Treaty 8 agreed to its terms for reasons of peace and friendship—ensuring what they thought would be a partnership*" (Treaty Eight 2010). The Aboriginal residents relied upon traditional land uses including trapping, hunting, fishing, food gathering, and spiritual uses. They were later joined by Métis populations in the region reflecting the long history of social interaction between Aboriginal residents and European immigrants.

The Athabasca oil sands region, which is the only oil sands region subject to the massive land disruption caused by surface mining, is home to the First Nations of the Athabasca Tribal Council, comprised of the Athabasca Chipewyan First Nation, the Chipewyan Prairie First Nation, the Fort McKay First Nation, the Fort McMurray First Nation, and the Mikisew Cree First Nation. Further population details on these communities are found in Sections 10.2.1 and 10.4.1.

Urban population centers in the Athabasca oil sands region are governed by the Regional Municipality of Wood Buffalo with a current population of about 90,000, dominated by the city of Fort McMurray with about 64,000, another 22,000 in industry work camps and about 4,000 in rural areas including the communities of Fort McKay and Fort Chipewyan (see Figure 3.3 and Section 10.4.1).

As will be elaborated in Part 2 of this report, the environmental footprint of bitumen production activities is considerable, with major air, water, and land dimensions (discussed in Sections 6, 7, 8, and 9). Air emissions (Section 6 and 7) are large both absolutely and in comparison to those associated with conventional crude oil production in the province and other industrial activities in Canada (Table 7.2). The management of water used in and generated by bitumen extraction processes also gives rise to environmental concerns, notably the storage and ultimate disposition of tailings generated by processing wastes from surface mining operations (Section 8). There are enormous land disturbance and reclamation issues that encompass dealing with the scarred landscape left by surface mines and the forest clearing that is characteristic of in situ production (Section 9).

The environmental footprint has a key *social* dimension, because the oil sands deposits are located within or near First Nations reserves or traditional hunting grounds, with major potential lifestyle- and health-related implications. It is precisely these kinds of environmental and social issues that are not fully captured by analyses of net macroeconomic impacts of the types mentioned in Section 1.1. Addressing this gap in part motivates the work undertaken in this review.

The first commercial bitumen production was achieved by surface mining accessible oil sands containing bitumen and adapting the Clark hot water separation process for bitumen extraction (Sections 3.1.3 and 4.1). In situ bitumen production began with the cyclic steam stimulation (CCS) process in the Cold Lake deposit and more recently has expanded rapidly with the steam assisted gravity drainage (SAGD) process (Section 4.2).

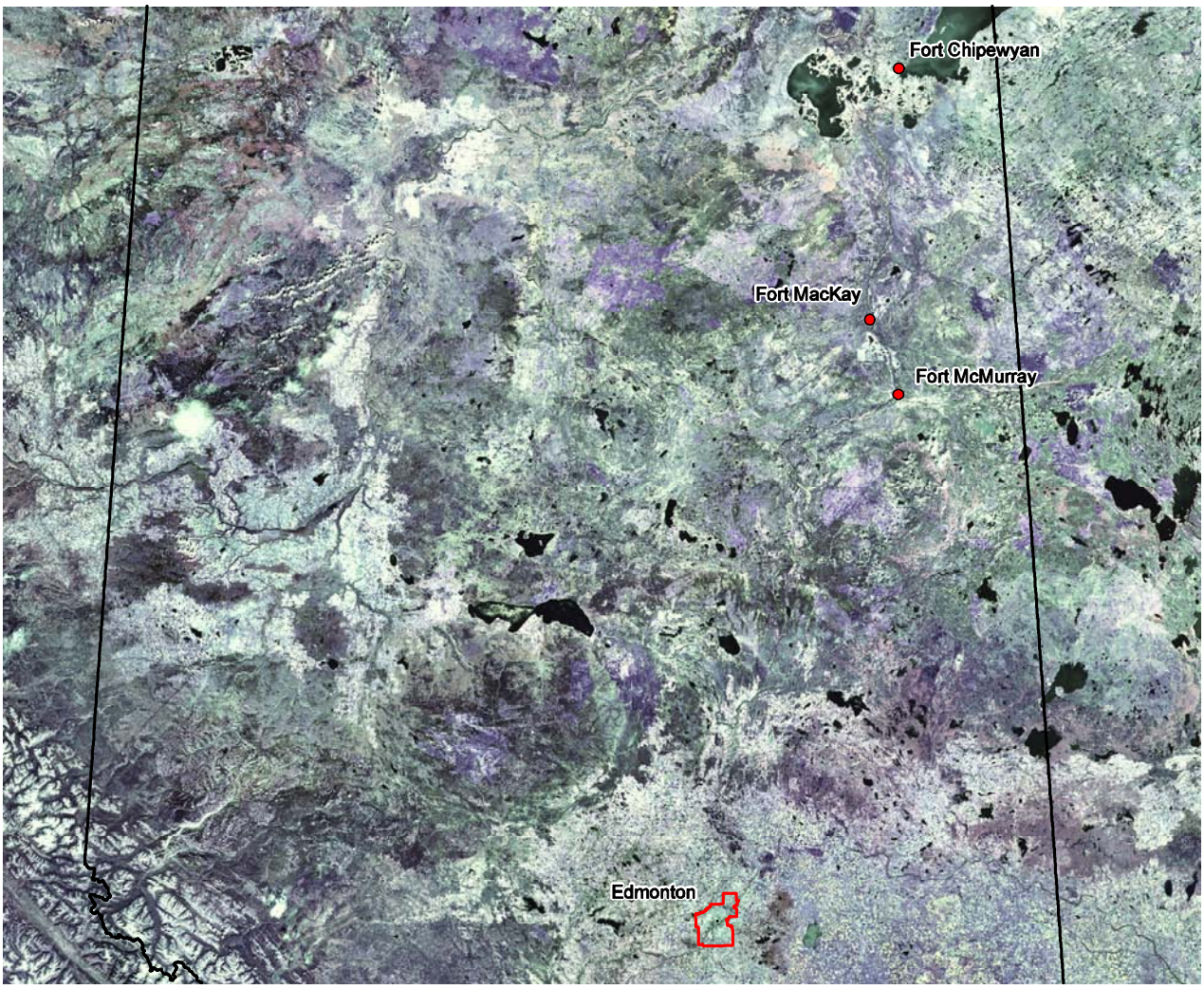
But the story of bitumen production does not end here, since much of this output cannot be processed "as is" by standard refineries. Instead, bitumen is typically transformed into synthetic crude oil, which can then much more readily be used as refinery feedstock. This transformation, called "upgrading" in Canada, consists of processing the bitumen to remove sulphur and carbon, and to add hydrogen (Section 4.5).[9] In any case, upgrading requires significant up-front capital investments and gives rise to large, ongoing operating expenditure flows. As with bitumen production activities, upgrading has been estimated to generate positive net macroeconomic impacts mainly, but not exclusively, in the province where the capacity is installed (again, Alberta). In turn, upgrading activities generate environmental challenges of their own, especially in terms of GHG emissions since current practices use natural gas as the source of the hydrogen needed in the transformation process. Because natural gas is the fossil fuel with the lowest GHG emissions per unit of energy produced, this use raises a concern that this resource that could be used in other applications is being consumed in bitumen upgrading (Section 6).

The operating environment of the oil sands industry is profoundly affected by the answer to a simple question: who owns the bitumen found in the deposits? Canadian constitutional provisions are quite clear on this matter: ownership rights to natural resources (such as natural gas, conventional oil, and bitumen) are vested in the provinces in which these resources are located. Since very few of these rights have ever been sold to private interests, it is estimated that about 97% of oil sands deposits in the province are still publicly held (AB Energy 2009, p.3). Therefore, Alberta's oil sands deposits and the bitumen embedded in them are almost entirely owned by current and future generations of Albertans.

In its capacity as the agent of the owners, the Government of Alberta can thus materially affect the industry's operating environment through legislation and related regulations aimed, in particular, at shaping the conditions under which bitumen can be extracted and processed within the province. This situation creates a responsibility for the Government of Alberta, as agent for Albertans who own the resource, to manage the oil sands resource—with all of its environmental and health implications—in the public interest, considering both immediate and longer-term horizons. Likewise, the Government of Canada has a major responsibility in terms of interprovincial and international trade of oil sands products, while being recipient of important tax revenue from these developments.

[9] Note that in the United States, the upgrading process is typically integrated into the operations of complex, or highly complex, refineries.

Figure 3.3 Satellite photo of Northern Alberta showing communities in the Athabasca oil sands region



Source: Image created by Rick Pelletier; satellite image was derived from the EarthSat Natural Vue Global Landsat Mosaic from Earth Satellite Corporation (EarthSat), published by ESRI, 20080401.

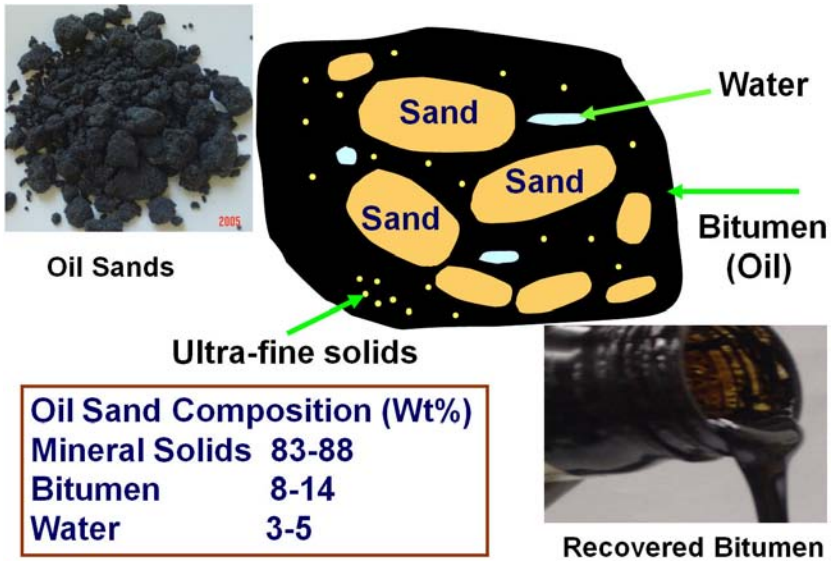
4. CURRENT AND EMERGING OIL SANDS TECHNOLOGY

4.1 Introduction

As noted in Section 1.1, there are an estimated 400,000,000 m^3 (2.5 trillion bbl) of bitumen-in-place, and about 27,000,000 m^3 (170 billion barrels) of bitumen can be economically recovered with current technology. To appreciate bitumen recovery processes and the social, economical and environmental impact of bitumen production from Alberta oil sands, it is important to understand the properties of oil sands deposits (formation). Compared with conventional and heavy crude oil, crude bitumen features a much lower hydrogen-to-carbon ratio (about 0.125 wt/wt or 1.5 on atomic basis), higher molecular weight (between 500 to 800 Da), greater specific gravity (0.99 at 40 °C), and higher sulphur, nitrogen, and metal content. Crude bitumen must be upgraded before it can be refined to produce jet fuels, gasoline, and other petroleum products.

A typical ore in the Athabasca oil sands contains between 8 to 14 wt% bitumen and 3 to 5 wt% water. The balance is solids, mainly coarse sands and fine silts and clays, which are in an unconsolidated form and impregnated with bitumen as schematically shown in Figure 4.1. At room temperature, bitumen has viscosity in the order of $5x10^5$ mPa.s and is virtually immobile. However, the viscosity of bitumen is highly dependent on temperature. At 50 °C, for example, the viscosity of bitumen decreases approximately 100-fold explaining why thermal energy is almost universally used for bitumen production from oil sands.

Figure 4.1 Characteristics of Alberta oil sands

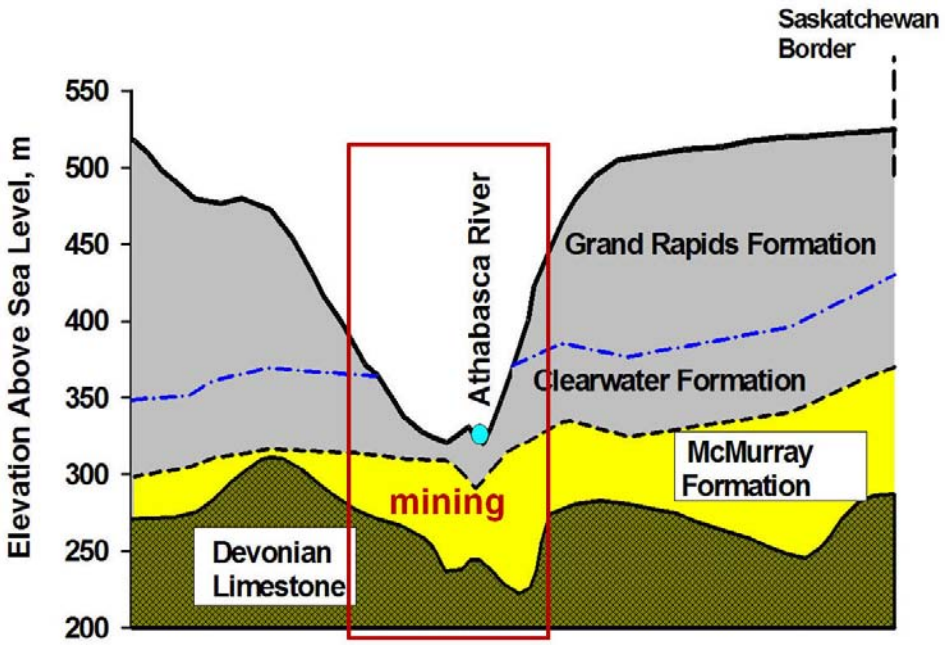


Source: Figure courtesy of Jacob Masliyah and Zhenghe Xu, adapted with permission

In Figure 4.2, oil sands deposits (McMurray formation) are located at different depths from the earth's surface, typically ranging from tens of metres to a few hundred metres. To produce oil from oil sands, different approaches are needed to access the oil sands formation, depending on the thickness of

overlay materials (Grand Rapids and Clearwater formations in Figure 4.2). These materials are known as overburden in the mining and oil sands industry. With current oil prices, an overburden to formation volume ratio, known as strip ratio, of 2 is considered economical for accessing the oil sands formation by open pit mining. The open pit mining method is applicable for formations of overburden up to about 70 m. Oil sands formations with overburden thicker than 150 m can be safely accessed through wells, a similar approach to heavy oil production and known as the in situ method. The oil sands reserves amenable for open pit mining operations are shown schematically by the box in Figure 4.2. They account for about 20% of total oil sands reserves. In 2009, on a daily average, Alberta produced 830,000 barrels of crude bitumen by open pit mining, accounting for more than 55% of total crude bitumen production. A key measure of oil production from oil sands is bitumen recovery, defined as the percentage of bitumen in place that is recovered during the operations. For open pit mining operations, bitumen recovery is typically higher than 90%, while it is only around 50% by current in situ methods. Strictly from a hydrocarbon resource utilization perspective, open pit mining is more attractive because it maximizes recovery of the bitumen-in-place.

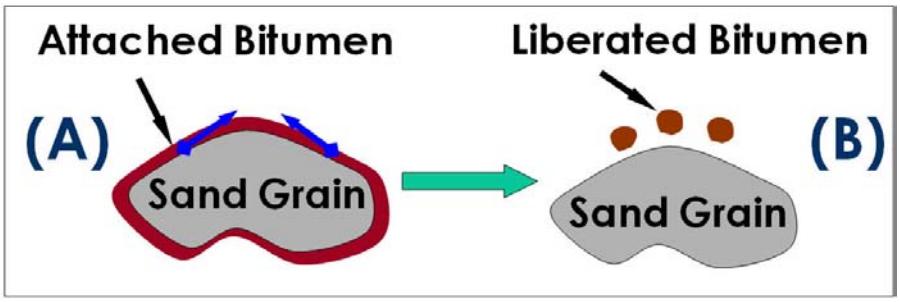
Figure 4.2 Vertical location of Alberta oil sands formations (vertical scale expanded)



Source: Figure courtesy of Jacob Masliyah and Zhenghe Xu, adapted with permission

Regardless of the methods used for oil production from oil sands, a critical requirement is detachment (liberation) of bitumen from sand grains as schematically shown in Figure 4.3. Bitumen liberation requires flow of bitumen initiated by thermal, mechanical, and/or chemical energies. The principal technologies used in oil production from oil sands, including both bitumen production and upgrading, are described below.

Figure 4.3 Bitumen liberation from sands grains is essential for bitumen recovery



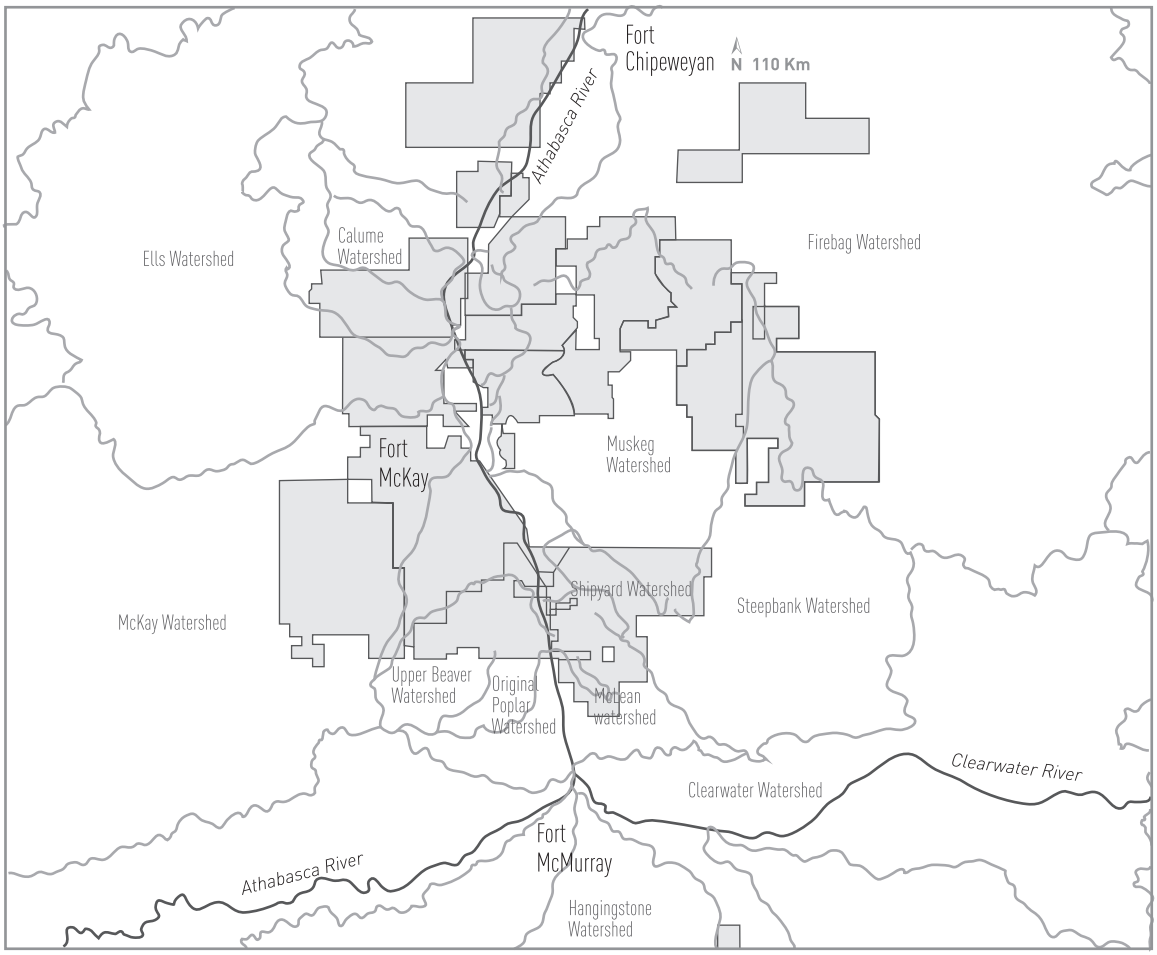
Source: Figure courtesy of Jacob Masliyah and Zhenghe Xu, adapted with permission

4.2 Open Pit Mining Bitumen Recovery

4.2.1 Current Technology

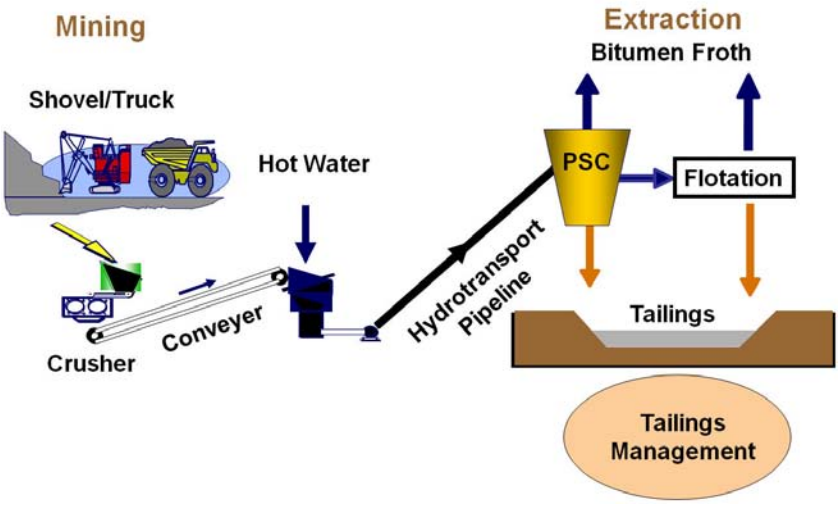
The locations of current and approved open pit mining projects are shown in Figure 4.4. The current bitumen production process by open pit mining is schematically shown in Figure 4.5. The muskeg and overburden above oil sands formations are removed by shovels and transported by trucks. The muskeg is stored for land reclamation use, while the overburden, mainly clays and sands, is stockpiled or used for building roads and tailings dykes. After exposure, oil sands are mined with shovels and trucked to crushers where oil sands ore is broken into smaller lumps. Compared with the early mining method of bucket-wheels, draglines and conveyors, the use of shovels and trucks in mining provides much greater flexibility for mine planning and ore blending, which allows optimization of process performance without major interruptions of operations.

Figure 4.4 Locations of operating and approved oil sands open pit mining projects



Source: RAMP 2009

Figure 4.5 Flow chart of bitumen recovery from Alberta oil sands using the open pit mining method



Source: Figure courtesy of Jacob Masliyah and Zhenghe Xu, adapted with permission

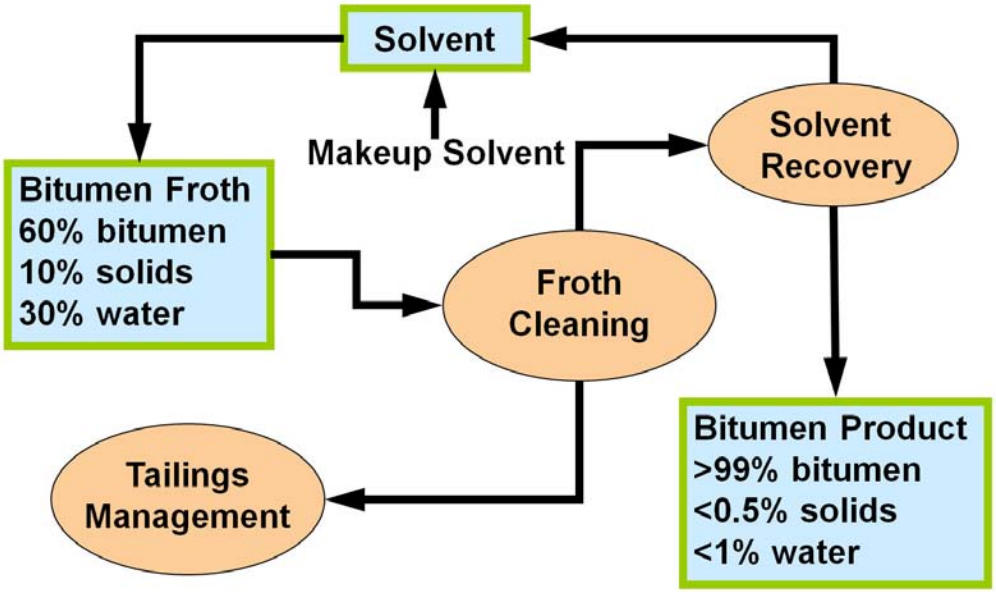
After crushing, the oil sands ores are transported by conveyor to a slurry preparation plant, where hot water is added to make a slurry at temperatures between 45 to 60 °C, depending on availability of thermal energy. To facilitate bitumen separation (liberation) from solids, chemical aids, typically sodium hydroxide, are added to generate needed natural surface active molecules from bitumen that aid in bitumen liberation and fine solids dispersion. The slurry is then transported through a slurry hydrotransport pipeline for up to 5 km, which is used to condition the slurry. The length of slurry hydrotransport pipelines depends on processing plant location, slurry temperature and initial lump size. In the slurry hydrotransport pipeline, hydrodynamic forces from high speed flowing slurry (typically 3–5 m/s) liberate bitumen from the sand grains, break the liberated bitumen into small droplets, and promote attachment of the liberated bitumen droplets to entrained air bubbles. Since bitumen has almost the same density as the processing fluid (water), attachment of liberated bitumen droplets to air bubbles is essential to enrich/recover the liberated bitumen from the slurry by gravity. Compared with previous ore digestion technology by tumblers operating at a much higher temperature with steam addition, the slurry hydrotransport pipeline invented for oil sands slurry conditioning, commercialized in 1996, represents one of the most innovative and important success stories of technology development for the oil sands industry, reducing energy intensities of bitumen extraction by up to 40%.

At the end of the slurry hydrotransport pipelines, the conditioned slurry is discharged to large stationary particle separation cells (PSC). In the PSC, the aerated bitumen floats through the slurry upwards to the top of the cell where it overflows and is collected as primary bitumen froth. The coarse solids settle quickly to the bottom of the PSC, while fine solids with some un-aerated fugitive fine bitumen droplets remain suspended in the slurry. The coarse solids in the form of dense slurry are taken out from the bottom of the cell as tailings, while the low–slurry-density, fine solids suspension containing fugitive bitumen is taken from the middle of the separation cell as a middlings stream.

To recover as much bitumen as possible for a given amount of ore, the middlings stream is further processed using flotation technology by either mechanical flotation machines or flotation columns in which more air is added to enhance bitumen–air attachment. The aerated fine bitumen droplets are recovered as secondary bitumen froth which is either returned to the PSC for further cleaning or sent with the bitumen froth from the PSC to the subsequent bitumen froth cleaning. In some cases, the tailings from the PSC are sent to the tailings oil recovery (TOR) unit known as secondary separation cells or to flotation cells for further recovery of bitumen contained in the PSC tailings.

The collected bitumen froth typically contains 60 wt% bitumen, 30 wt% water, and 10 wt% fine solids, which requires further cleaning in a froth-cleaning plant before the crude bitumen product is suitable for upgrading. After removal of the air in the bitumen froth by a de-aerator, solvent is added to the bitumen froth at the froth cleaning step (also known as froth treatment). A typical froth cleaning process flowchart is shown in Figure 4.6. The solvent added solubilizes bitumen to form a diluted bitumen mixture of bitumen and solvent. The purpose of diluting the bitumen is to reduce its viscosity and density, thereby facilitating the separation of water and fine solids from the organic phase of diluted bitumen. Depending on the type of solvents used, there are two main technologies currently in place for froth cleaning. The choice of solvent is determined by availability of solvents and downstream bitumen upgrading process options.

Figure 4.6 Schematic flow diagram of bitumen froth cleaning (treatment) process using naphtha as the diluent of choice



Source: Figure courtesy of Jacob Masliyah and Zhenghe Xu, adapted with permission

Whenever an on site upgrader is available for bitumen upgrading, naphtha as a by-product of bitumen upgrading is used as the solvent, known as diluent. In this case, a diluent-to-bitumen volume ratio is controlled between 0.6 to 0.8. The diluted bitumen is separated from the water and solids in the bitumen froth by gravity separation using a combination of inclined plate settlers, cyclones, and/or centrifuges—a process known as naphthenic froth cleaning. The solvent in the diluted bitumen is recovered by distillation towers known as diluent recovery units, producing a bitumen product containing 98 wt% bitumen, 1–2 wt% water, and 0.5 wt% solids. The bitumen product produced is suitable for various upgrading processes. The recovered solvent is recycled to the front of froth cleaning for use as diluent.

When the upgrading facility is not available on site, paraffin liquids of five to six hydrocarbons (C_5-C_6) are added as diluent at about 2:1 diluent-to-bitumen volume ratio whereby large polyaromatic molecules, known as asphaltenes, are selectively precipitated as rejects. The asphaltene rejection level is determined by controlling the solvent-to-bitumen ratio to maximize the hydrocarbon recovery while producing a product of desired properties for down-stream upgrading. The asphaltene precipitates in this case act as a flocculant to bind fine water droplets and clays, facilitating gravity separation of diluted bitumen from the solid-containing aqueous phase. With effective flocculation, separation of diluted bitumen from the aqueous phase is currently accomplished by a three-stage, counter-current thickener avoiding the use of energy-intensive and high-maintenance centrifuges, thereby reducing GHG emissions and enhancing productivity. After removal of the diluent, the bitumen product has much lower water and solids content than the product produced using naphtha as the diluent. This process, known as paraffinic froth cleaning, is regarded as another significant oil sands innovation. In essence, the paraffinic froth treatment provides partial physical upgrading of bitumen by rejecting heavier-end asphaltenes. As in naphthenic froth cleaning, the solvent is recovered for recycling.

A common feature of the remaining aqueous phase (waste stream) separated from the diluted bitumen froth by gravity separation, known as froth cleaning tailings, is its higher hydrocarbon content, mainly the trapped solvent. The solvent in this aqueous stream is recovered by a tailings solvent recovery unit operating under distillation principles. The resulting aqueous phase containing mainly water and solids is discharged to the tailings ponds. Compared with the waste stream (tailings) from primary bitumen extraction, tailings from the froth cleaning process contain a relatively higher quantity of organics (residual solvent and bitumen) and enriched heavy minerals. Generally four volumes of solvent are lost for every 1,000 volumes of SCO produced.

When a paraffinic solvent is used as a diluent, a portion of bitumen having lower hydrogen-to-carbon ratio and larger molecular weight, known as asphaltenes, is precipitated. From both economic and environmental perspectives, there are incentives to further recover this portion of lost hydrocarbons and the entrained diluted bitumen from the froth cleaning tailings before they are discharged to form total tailings.

At a 90% bitumen recovery, it takes roughly 11 tonne of oil sands to produce 1 m^3 (6.3 bbl) of SCO. To prepare the slurry suitable for slurry hydrotransport and bitumen recovery, approximately 2.5 m^3(16 bbl) of hot water are needed, of which 75% to 85% is recycled from the tailings ponds. After bitumen recovery, about 3.3 m^3 of fluid/solid waste remain, known as raw tailings, which are discharged to the tailings ponds. Generally, about 50% of the fine solids are trapped within the coarse solids forming a beach in the tailings pond. The bulk of the water and fine solids ends up in the tailings pond itself. For a typical plant of 47,700 m^3/d (300,000 bbl/d) bitumen production, 250,000 m^3/d (540,000 t/d) of oil sand ore are processed, producing close to 1,000,000 m^3/d of raw tailings. The majority of water contained in the raw tailings is currently reused, which reduces containment volumes of ultimate tailings. Over time, fine solids in the tailings pond water form a sediment referred to as mature fine tailings (MFT). Without treatment, on average 1 m^3 of SCO production from oil sands produces on average about 2 m^3 of MFT.

The tailings from bitumen extraction and froth cleaning are typically discharged separately to a tailings pond as process waste, where coarse solids settle quickly to build dykes and beaches, while fine solids settle slowly to form fluid fine tailings and eventually become MFT over time, with clarified water in the tailings pond being recycled back to bitumen extraction. Unfortunately, the volume of MFT containing no more than 30 wt% fine solids accumulates at a rate of more than 20% of the volume of oil sands excavated from the mine. The current tailings ponds in operation occupy a total area of about 130 km^2 with an estimated tailings volume of 720 million m^3 (ERCB 2009). With continuing operation of oil sands plants, the volume of MFT would increase at an alarming rate if it were not treated. The large volume of MFT traps a large quantity of water while tailings containment incurs a direct incremental operating cost. A large area is needed to contain the fluid fine tailings, not only leading to coverage of valuable land surface, but also posing a major liability if tailings containment fails. Any loss of containment structure might lead to a catastrophic disaster.

Considering intensive water usage in oil sands development as documented by Allen (2008), there are great incentives to treat fluid fine tailings or MFT so that the maximum water can be recycled to reduce fresh water intake for bitumen extraction and to minimize the volume of tailings to be

contained. A number of inroads have been made, including composite/consolidated tailings (CT) process, thin lift drying, and potentially chemical assisted centrifugation/filtration. Only a brief summary of these emerging technologies is given here.

In the CT process, either thickened tailings from thickeners or MFT from tailings ponds are mixed with coarse sands (cyclone underflow) of extraction raw tailings at a sand-to-fines ratio (SFR) of 3–4. Gypsum is added to the mixture to coagulate fine solids along with the added coarse sands. The coagulated fines would have similar settling characteristics as coarse sands and trap coarse sands to form a dense slurry mix that does not segregate during transport, discharge, and deposition of CT mix. The treated CT mix releases water rapidly for recycling, while consolidating solids up to 80 wt% for CT deposition in a confined area. After CT deposition, further consolidation occurs under the gravity of coarse sands mixed in to release remaining CT-affected water. The CT process, first implemented in 2000, represents the first commercially successful tailings treatment technology for MFT reclamation (Matthews et al. 2002). Despite its potential to reduce the inventory of MFT, the full scale implementation of the CT process remains rather limited because of the undesirable chemistry produced in the released water, notably the high concentration of calcium ions which are detrimental to bitumen extraction and cause scaling in pumps, pipes, and valves. Developing more effective coagulants with less impact of recycled water on bitumen extraction may facilitate the commercial use of the CT process for oil sands fluid fine tailings treatment. Use of CO_2, a greenhouse gas (GHG), as a coagulation agent would resolve the water chemistry issues in bitumen recovery with beneficial potential of water softening and CO_2 sequestration. The CO_2-assisted oil sands tailings treatment technology is currently under development.

To improve energy efficiency and reduce fresh water intake by recycling the maximum amount of warm water as quickly as possible from oil sands extraction tailings, there are incentives to treat these tailings as they are produced. To this end, the paste technology or thickened tailings (TT) process has been developed for oil sands tailings. In the TT process, polymers are added as flocculant to warm raw fine tailings, often the overflow of hydrocyclone. The large molecular weight polymers bridge fine particles effectively, forming large size, but low density aggregates (flocs). With proper dose and addition of flocculants, the flocculated warm fine tailings are fed to a large thickener where particle flocs settle quickly to a solids content of 30 wt% in the sediments (underflow), producing a clean overflow of less than 0.2 wt% solids. Quick clarification allows the clarified warm water (overflow) to be recycled back to bitumen extraction while it is still warm, reducing thermal energy needs for heating oil sands slurry. This tailings management strategy is being used in one oil sands operation. The only downside of this approach is that the sediments remain dilute (30 wt% solids), which requires proper confinement or further densification with coarse sands as in the CT process.

Further development of the TT process showed that with a combination of flocculation and coagulation, fresh oil sands tailings can be thickened in a deep-cone thickener to solids content above 60 wt% in the sediments, while remaining pumpable for transportation. The flocculated fine solids–liquid separation can be further enhanced by centrifugation or hydrocyclones of higher g-forces to reduce separation time. The sediments of this level of solids content can then be placed on an open field in thin layers for natural drying. The technology based on this concept is known as thin lift drying

and will be further tested for implementation in new oil sands projects. There is little polymer left in recycled water as the polymer is added at ppm levels and is mostly attached to the flocculated solid particles. There are some efforts to investigate the addition of flocculant in the bitumen extraction process for improving not only tailings settling, but also bitumen recovery and bitumen froth quality. The success of this concept relies largely on development of novel flocculants with desired mechanical strength and selectivity for fine solids.

Another technology known as thin lift drying (also known as tailings reduction operations) is currently being field-tested for treating fluid MFT already in inventory. In this technology, the flocculated fluid MFT are deposited in thin layers over a large open area for natural drying prior to deposition of the next thin layer of flocculated paste. Drying the thin lift layers requires a large landscape. Applying thin lift drying to fresh tailings would mean that warm water trapped in thickened tails gets lost during evaporation by natural drying and is not available for recycling. It is therefore beneficial to develop a process that produces stackable solids for backfill and immediate land reclamation of mined pits while recycling a maximum amount of warm water to reduce the intake of fresh water for oil sands operations. Placing solids back to the mined pits will also greatly reduce the need for tailings ponds or land needed for thin lift drying. Ideally, the fresh water consumption would be reduced to the amount that only replaces the volume of recovered bitumen in place. Clearly this should be an ultimate goal of oil sands tailings management.

4.2.2 Emerging Technologies

A well-known challenge facing the oil sands industry is the energy intensity of bitumen production from mineable oil sands deposits, which translates directly to the reduction of the carbon footprint. Although access and transport of oil sands ores by shovels and trucks provides great reliability and flexibility for mining operations, the transportation of a huge amount of materials (540,000 t/d of ores for 47,700 m^3/d production of SCO) using trucks, as shown schematically in Figure 4.7, is one of the major sources of higher energy intensity. Not only is energy consumed to transport oil sands ores by trucks, but moving heavy-duty trucks themselves (an empty truck could be as heavy as 150 tons) also consumes a large quantity of energy almost equivalent to that needed for transporting ores from mine site to processing plant, not to mention the maintenance cost of trucks and tires.

Figure 4.7 Transport of large quantity of oil sands ores by large trucks contributes to the energy intensity of bitumen production from oil sands

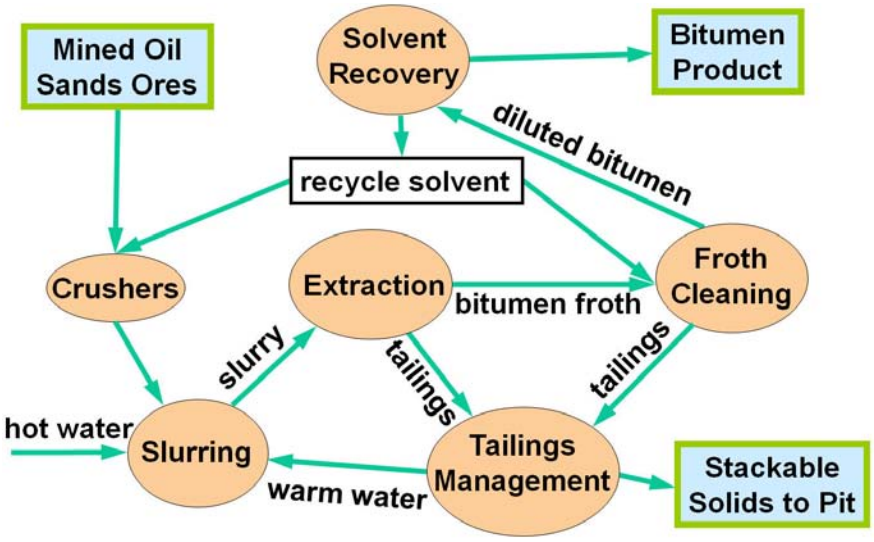
Source: Photographs courtesy of Jacob Masliyah and Zhenghe Xu, adapted with permission

A possible solution to reduce energy intensity of materials transportation is to avoid transporting solids by on-site rejection of coarse sands as they are mined. In this regard, the oil sands industry is developing a mobile at-face slurrying and digestion system. The success of this technology would allow the rejection of approximately 60–70 wt% mined materials in the form of coarse sands. With the success of such technology, only the fine solids slurry needs to be transported, which can be accomplished by slurry hydrotransport without use of heavy-duty trucks. Eliminating heavy-duty trucks by more energy-friendly slurry hydrotransport will reduce not only the energy cost, but also GHG and NO_x emissions related to diesel consumption by heavy duty trucks. Hydrotransport of fine solids slurry after rejecting coarse solids at the mine face (on site) leads to a significant reduction in energy cost and maintenance cost related to wear of pipe and pumps by transporting slurry at a lower flowing velocity. However, at-face slurring and digestion would lose the flexibility of ore blending. To deal with such limitations, there is a need to develop a more robust extraction technology operating at lower temperatures, such as aqueous-nonaqueous hybrid extraction processes, as will be discussed below.

Energy intensity for bitumen extraction can be further reduced by operating the extraction process at lower temperatures. A reduction in thermal energy intensity by 5 MJ/ton of ores processed is estimated if the operating temperature of bitumen extraction can be reduced by just one degree Celsius. For a plant producing 48,000 m^3/d (300,000 bbl/d) of SCO, this represents a daily energy saving of 3,000 GJ. For this reason, the oil sands industry has been working diligently to develop new technologies that allow lower operating temperatures. In the early stages of commercial oil sands operations, bitumen extraction was operated at 75–80 °C. Steam was needed to raise the slurry temperature to this level.

High bitumen viscosity was the reason for using high temperature extraction. A significant technological innovation in the oil sands industry is the use of slurry hydrotransport pipelines for bitumen conditioning. This revolutionary technology has enabled the operating temperature to decrease steadily to the current practice of 40–55 °C. To further reduce the operating temperature and maintain acceptable processability, an innovative approach to reduce bitumen viscosity by chemical means is needed. Considering the need to dilute the bitumen by solvent in bitumen froth cleaning, a hybrid aqueous–nonaqueous process as shown in Figure 4.8 is attractive.

Figure 4.8 Concept of aqueous-nonaqueous hybrid bitumen extraction process by changing traditional solvent addition scheme in conventional froth cleaning upfront of extraction



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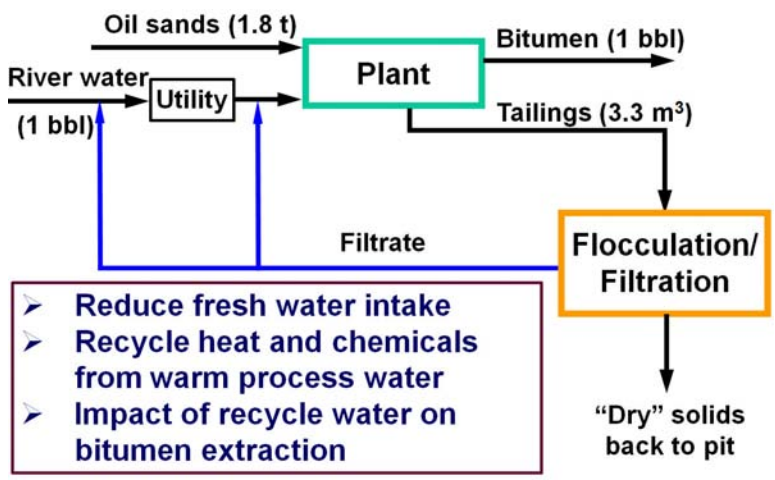
In this novel hybrid extraction process, a portion of solvent (30%) originally added in the traditional bitumen froth cleaning process (Figure 4.6) is added in the oil sands ore to reduce bitumen viscosity prior to its conditioning. Soaking of oil sands ore by solvent added at the crushing stage (crushers) (Figure 4.8) would bring the viscosity of solvent-soaked bitumen down to the level equivalent to that achieved by increasing the process temperature to above 45 °C so that bitumen extraction can be operated at ambient temperatures. The solvent soaked in bitumen is recovered into bitumen froth with bitumen. In this case, only the balance solvent is needed to proceed with bitumen froth cleaning as in the current commercial operating modes without any change in configuration of bitumen froth cleaning (Figure 4.8). A small fraction of added solvent may become lost in the tailings water of bitumen extraction, which can be resolved if the majority (80%) of the process water is recycled, bringing the solvent loss to a negligible level. Another source of solvent loss is the trapping of solvent by clay minerals, especially for ores with high fines/clay content. The extent and how the solvent is trapped by fine clays remains to be determined if trapped solvent is to be effectively and economically recovered. Clearly innovative technologies featuring aqueous–nonaqueous hybrid bitumen extraction integrated with closed loop process water recycling will enable production of bitumen from mineable oil sands with fewer environmental consequences.

For energy saving and reducing net fresh water intake for oil sands extraction, efforts should be placed on recycling as much warm process water as possible prior to raw tailings disposal. The use of filtration (Figure 4.9) appears to be a good option, as it could produce a solids cake of the lowest water content. In filtration, liquid in a suspension is forced to flow through the interstitial voids of a formed filter cake through application of pressure, vacuum, or centrifugal forces. A recent laboratory study has shown that by proper flocculation and settling of raw warm tailings, the filtration of the sediments could produce a stackable solids cake within an acceptable time frame making it practical for handling large volumes of oil sands tailings. The thickening of flocculated warm raw tailings by hydrocyclones and/or thickeners, followed by filtration, appears to be an emerging technology for managing both raw tailings and MFT, by blending the MFT with raw tailings. Coarse solids in raw tailings would further enhance MFT filterability. Full implementation of this tailings management concept would resolve environmental issues of water demand, liability of tailings storage, and corresponding land disturbance related to bitumen production from mineable oil sands deposits. This approach also preserves thermal energy contained in the warm recycled water needed for extraction. The challenge is to scale up the process from a laboratory concept to one that is capable of handling close to 1 million m^3 of raw tailings and consuming existing MFT. Further innovation will be the key to realizing this concept of tailings management.

Figure 4.9 A conceptual oil sands tailings process, producing stackable solids cake while recycling the maximum amount of water



Source: Figure courtesy of Jacob Masliyah and Zhenghe Xu, adapted with permission

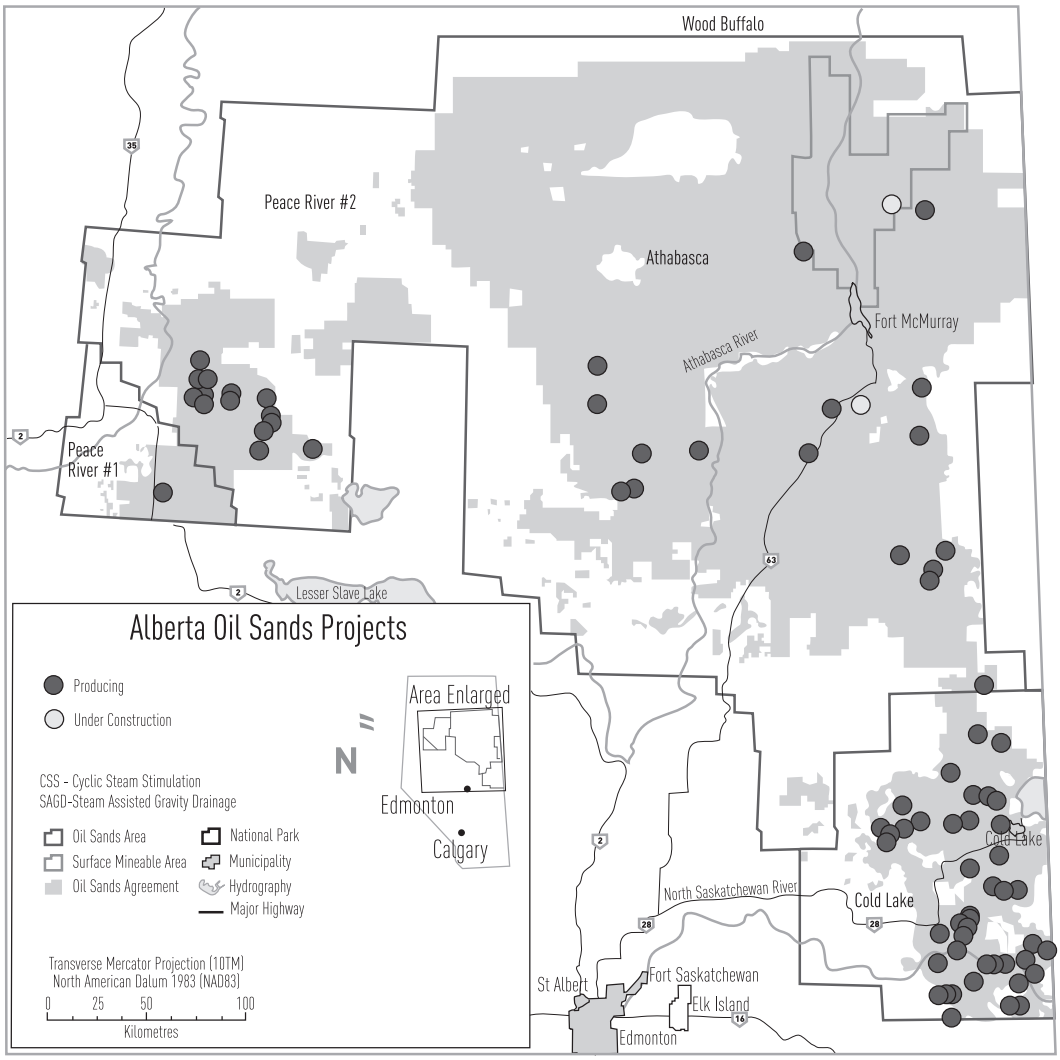
4.3 In Situ Bitumen Recovery

4.3.1 Current Technology

The locations of current in situ projects are shown in Figure 4.10. For oil sands deposits buried more than 150 m deep, production of bitumen using open pit mining becomes uneconomical. In this case, drilling technologies used in heavy oil production are adopted. This method of bitumen recovery is known as the in situ production method. Due to extremely high viscosity of bitumen, the approach to make the bitumen flow for its recovery at present is almost exclusively accomplished by thermal

energy. At steam temperatures above 250 °C, the viscosity of bitumen approaches the value for water thereby making bitumen flow like water. To achieve this temperature, high pressure steam is exclusively used in current practice. Depending on the type of wells, two principal in situ bitumen production methods known as cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD) are currently being used.

Figure 4.10 Locations of current in situ oil sands projects in Alberta



Source: AB Energy 2010

In the CSS method commercialized in 1985, also known as “huff and puff,” a single vertical well is drilled to reach the oil sands formation. Steam of 80% quality at 300–340 °C is initially injected through this well. The injected steam condenses while heating up the oil sands formation. After being soaked by the injected steam for several weeks, the heated bitumen in the form of bitumen-water mixture is pumped above ground through the same well. After recovering the heated mobile bitumen, typically over a 6- to 8-month period, the steam is injected again into the well and the cycle repeats until the well is depleted to the point that the cost of injecting steam becomes higher than the value of the product. The CSS production is mainly used for thick oil sands reserves such as in the Cold Lake

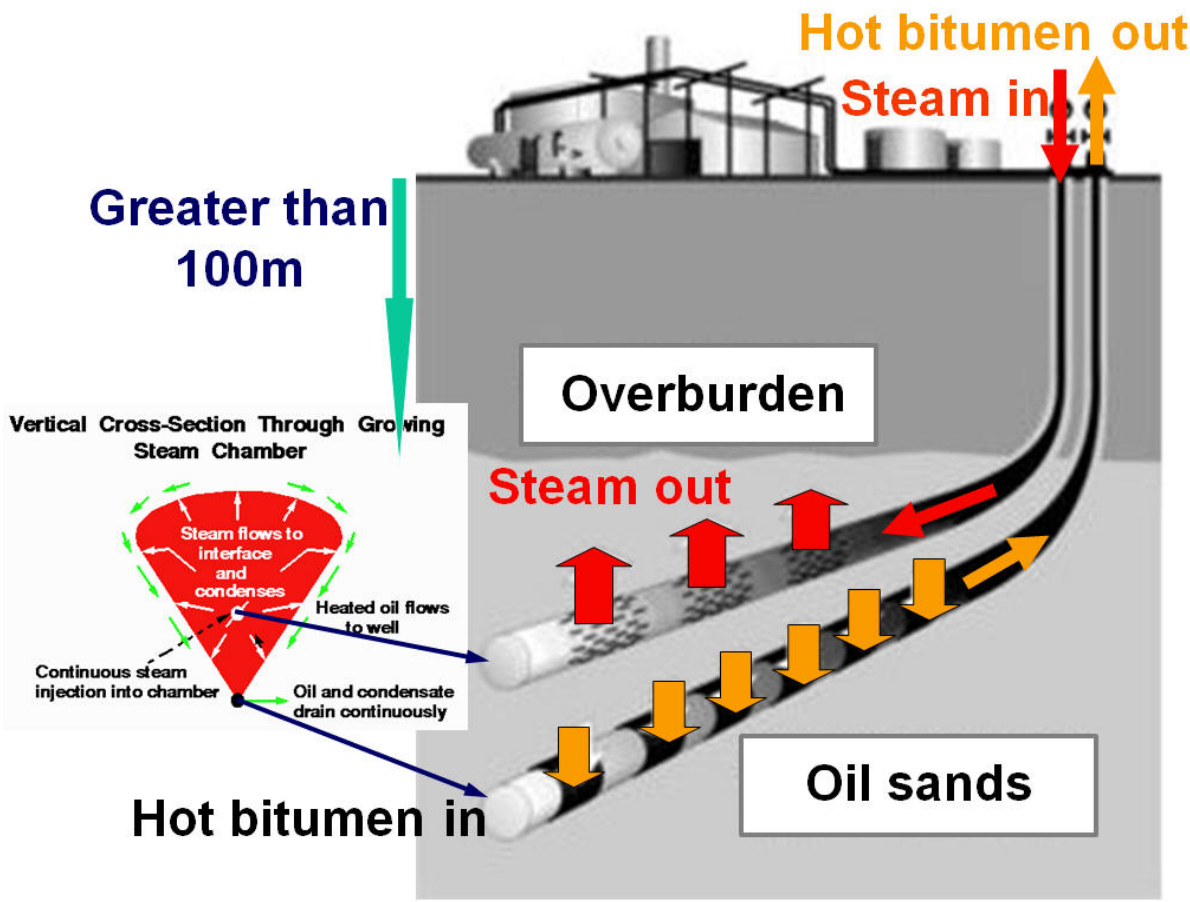
and Peace River regions of Alberta. Bitumen recovery by the CSS method is relatively low at 20–35% of bitumen-in-place.

SAGD was developed in the 1980s and is currently the dominant method for in situ bitumen production. Built on the success of horizontal drilling technology, the SAGD process allows bitumen production from thinner oil sands formations than CCS. SAGD is one of the most recognizable breakthroughs in oil sands exploration in which two horizontal wells are drilled (Figure 4.11). The lower well is drilled 1–2 m above the base of oil sands formation. The upper well is drilled parallel, about 5 m above the lower well. The wells of roughly 200 mm in diameter extend horizontally up to 1000 m. At the beginning of SAGD operations, steam of 100% quality (free of liquid water), normally above 250 °C and 9,600 kPa gauge pressure, are injected through and subsequently circulated between the two wells. The use of 100% quality steam avoids potential deposition of dissolved solids contained in liquid water present in lower quality stream. The oil sands formation is soaked for 3–6 months. The steam heats the oil sands formation to create a steam chamber above the upper well (Figure 4.11 inset). After full development of the steam chamber to mobilize the bitumen, the bottom well is switched to production mode. The mixture of hot bitumen and condensed steam (condensate) flows along the surface of steam chamber towards the production well under gravity. Through the production well, the bitumen-steam condensate mixture is produced at the wellhead above the ground by gas lift or by immersed pump. During bitumen production, steam is continuously supplied through the upper steam injection well while the steam chamber continues to grow with bitumen production. With greater access of oil sands formation by horizontal wells, each well pair produces up to 160 m^3/d (1,000 bbl/d) of bitumen. Such a production rate is 15 times higher than that of a typical CSS well and at a much lower steam-to-oil ratio than needed in the CSS process. As the heated bitumen drains under gravity to the production well, it carries fine solids. The solids migrating to the wellbore may accumulate around the wellbore or inside the production well thereby blocking the flow of produced fluids to the production well. This is known as sanding. To minimize solids entering the production well, liners of 0.1–0.3 mm width slots and wire wrap screens are inserted into the wellbore of the production wells. (Morgan 2001)

After produced fluids are lifted from the production well to above ground in the form of bitumen and steam condensate mixture, they are first de-pressurized to separate contained gases from produced fluids in a gas/liquid separator (Figure 4.12). After removal of water vapour, the produced gas (a mixture of produced gas and lift gas) is combined with natural gas, and used as fuel gas for steam boilers. Diluents (solvents) are added to the remaining produced fluid for the same purpose as in bitumen froth cleaning of mineable oil sands operations (Figure 4.6). The liquid/liquid mixture is separated in a liquid/liquid separator with the aid of chemical additives known as demulsifiers, by a few stages of gravity separation. The separated organic phase is further diluted with solvent to produce diluted bitumen (dilbit) product for the transportation to the downstream upgrading facilities. The aqueous phase, known as produced water from the liquid/liquid separator, is processed by a water treatment plant to remove residual oil/bitumen and salts. Oil removal is often accomplished by either dissolved air flotation or induced air flotation, followed by a walnut shell filter. Recovered oil is then fed back to a liquid/liquid separator (Figure 4.12). The water after oil removal normally containing less than 5 ppm oil is further treated by water softening using warm lime and MgO to remove hardness and

silica content, followed by ion exchange resins to produce boiler feed quality water for the steam generator. In some operations, evaporators are used to produce higher quality water which is fed to boilers for steam generation. During the water treatment, a small quantity of wet solids sludge is produced. They are discharged to a landfill site or injected into deep wells for secure disposal (ERCB 1994).

Figure 4.11 Schematic illustration of steam assisted gravity drainage (SAGD) underground well arrangement and steam chamber (inset)



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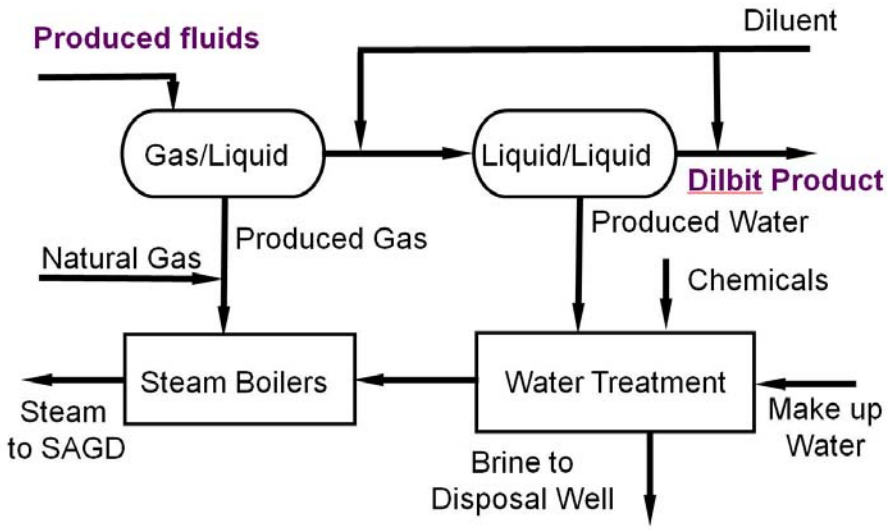
SAGD operates on nearly a zero discharge basis and only replacement water is needed for bitumen production. For a typical SAGD operation, 10 to 15 well pairs separated by 100–150 m are drilled with one pad to allow efficient handling of produced fluids and minimizing land surface disturbance. SAGD often operates at a steam-to-bitumen volume ratio above 2.5. Within the steam chamber bitumen recovery as high as 60% is estimated. Producing 0.16 m^3 (1 bbl) of bitumen at a steam-to-bitumen ratio of 2.5 requires approximately 35 m^3 (1250 SCF) of natural gas (1.6 GJ) for steam production, which accounts for roughly 20% of the energy contained in the produced bitumen. The energy intensity of SAGD operations is very much dependent on the steam-to-oil ratio and in situ bitumen recovery.

Figure 4.12 Schematic flow diagram of above ground processing in a typical SAGD operation



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4.3.2 Emerging Technologies

Considering the high value of natural gas (NG) and associated intensity of GHG emissions for steam generation, there are major incentives to reduce the steam to oil ratio (SOR) and improve bitumen recovery of SAGD operations from both an economic and an environmental perspective. Extensive research and development efforts have been made to progress in this direction. A direct approach to reduce natural gas demand is to use alternative fuels, such as coal, petroleum coke, and bitumen residues (such as rejected asphaltenes) in co-generation of steam and electricity (McKellar et al. 2010). Such an approach not only provides heat for in situ bitumen production and power for operating plants from a cheaper energy source, but also produces hydrogen for bitumen upgrading and provides a point source of CO_2 suitable for GHG capture and storage (CCS). Opti-Nexen SAGD operation represents this kind of integrated operation incorporating controlled removal of asphaltenes from bitumen by solvent, thermal cracking, gasification and co-generation to produce high quality SCO. This approach will be discussed in greater detail later in this Section.

An alternative to replacing the steam or reducing steam demand is to use light hydrocarbon (e.g., propane) injection or steam-solvent co-injection to reduce the viscosity of bitumen in oil sands formation. The former is known as the VAPEX (vapour extraction) process and the latter as the steam-solvent hybrid process. In the VAPEX process, a non-condensable gas such as methane is co-injected with a condensable gas such as propane near its dew point. Bitumen in oil sands formation initially dissolves in the condensed solvent near the injection well, until it breaks out to the horizontal production well. The solvent-diluted bitumen in the solvent chamber continuously drains under gravity to the production well where it is lifted above ground for further processing. With these alternative SAGD processes, bitumen can be produced at much lower pressure and reservoir temperature with minimal need of water, leading to lower heat loss and CO_2 emissions. In the VAPEX process, higher quality (lighter) bitumen is produced by controlled precipitation of asphaltenes during in situ

production. The VAPEX process is particularly attractive for oil sands formations containing swelling clays which may damage permeability of the steam chamber when coming into contact with steam. The challenge of implementing these technologies lies in the availability and handling of large volumes of solvent, coupled with effective recovery of injected higher value solvent and its potential seepage or diffusion into ground water. The implications of using VAPEX remain to be field-established. Recent studies have indicated the potential of using CO_2 as a non-condensable gas mix in the VAPEX process. CO_2 is known to dissolve in bitumen, which can contribute to reduction in bitumen viscosity. As in enhanced oil recovery (EOR) of heavy oil, the advantage of using CO_2 as a gas mix is its wide availability and low cost. This process may also contribute to reduced GHG emissions.

To improve bitumen recovery without increasing SOR, chemical-assisted SAGD has been proposed. In this method, chemicals are delivered with steam of lower than 100% quality. The purpose of chemical additives is to increase wettability of solids in the oil sands formation and enhance mobility of bitumen by creating an alkaline environment with reduced oil-water interfacial tension. An increase in bitumen recovery by a few percent often translates to both increased economic gains and reduced environmental consequences. Understanding oil sands formation characteristics, in particular the heterogeneity of the formation is considered as a key element (Al-Bahlani and Babadagli 1994) for a greater success of SAGD. The geological heterogeneity in oil saturation, density and viscosity of oil in oil sands formation is shown to impact bitumen production rate, CSOR and thermal efficiency of operation by SAGD methods (Larter et al. 2008). The geological heterogeneity of oil sands formations accounts for a wide range of CSOR in SAGD from 2.5–4.5, with an average around 3.2 (ERCB 2010; Gates and Chakrabarty 2010). To improve oil production and reduce CSOR, particularly for thin oil sands formations, the concept of cross SAGD, known as XSAGD, has been tested (Stalder 2009). Arranging the horizontal steam injection wells across the horizontal producing wells at various angles was found to accelerate communication between injection and producing wells by combining gravity drainage with lateral displacement, leading to an increased production rate and reduced CSOR.

For oil sands formations of intermediate thickness of overburden, in situ electrical induction heating and microwave heating technologies, known as the electro-thermal process, are emerging. In the electro-thermal process, electromagnetic energy applied via a series of wellbore electrodes, engineered along the well casing is converted in situ to thermal energy. There are two modes of electrical stimulation of oil sands formations, known as inductive and resistive stimulation (Vermeulen and McGee 2000). For inductive stimulation, heat is generated by flowing electric current through a transformer inside the steel casing at the bottom of the wellbore. Large induced currents resistively heat the steel of the casing and the heat is transferred to the formation by thermal conduction. There is no electric current flowing through the reservoir in inductive stimulation. For resistive stimulation, electric current is forced to flow in the reservoir between electrodes. The current flow through oil sands formation is by ionic conduction through formation water of high electrolyte (salt) concentrations. Aqueous electrolyte (formation water) is an essential ingredient in this mode of electro-thermal operations. To avoid the formation water drying out a recirculating water stream at very low flow rate of around 1 m^3/electrode day is continuously injected into the ends of the electrode, where the power density is the highest. The circulating water flow ensures a more uniform current flow

across the electrodes. By imposing this water flow in the electro-thermal process, the heat transfer to the formation is accomplished by a combination of heat conduction and convection.

The in situ electro-thermal recovery of bitumen from oil sands is viewed to be free of issues related to low initial formation injectivity, poor heat transfer, presence of shale layers between rich oil sands layers, and difficulties of controlling the movement of injecting fluids (liquid and gases) as encountered in other in situ recovery processes. The thermal efficiency in a properly designed electro-thermal process can be three times more effective than in the SAGD process. With electric heating, bitumen production can be accomplished at a much lower pressure, ensuring rock cap integrity during the production. The location of electrodes and extraction wells is of paramount importance as it determines pressure distribution in oil sands, which in turn determines bitumen recovery. In general, a large number of electrode wells typically separated from each other by 16 m are drilled into the oil sands formation in a grid form. The electrodes are fabricated from a thin wall carbon steel of 0.3 m diameter to 6 m tall, and are spaced 10 m apart in the vertical direction. The vertical extraction wells are placed in the middle of two neighbouring electrode wells. The thermally mobilized bitumen is pumped above ground for further processing using technologies employed in SAGD above-ground operations. Bitumen recovery with such an electro-thermal well arrangement is comparable to bitumen recovery by a productive SAGD project. Considered as a more environmentally-friendly technology with lower water and energy intensity, the electro-thermal dynamic stripping process, known as ET-DSP^{TM}, has been successfully field-tested at 160 m^3/d (1,000 bbl/d) in situ bitumen production rate (CAPP June 2009). Recently, additional funding was secured to further field-test the technology at 1,600 m^3/d (10,000 bbl/d) scale before its full scale commercialization.

4.4 Summary Comparison of Surface Mining and In Situ

To conclude, it is useful to compare bitumen production by open pit mining and in situ SAGD method. A summary comparison is given in Table 4.1. Relatively speaking, bitumen production by SAGD is more energy intensive with lower bitumen recovery, contributing to greater GHG emissions as compared to open pit mining. On the other hand, SAGD requires less water and causes minimal direct land disturbances, featuring a lower capital cost per m^3 of bitumen production. Considering the much larger reserves amenable to bitumen production by in situ technology, it is important to devote a greater effort to developing more energy- and environmentally-friendly in situ methods for bitumen production. In this regard, an integrated approach of the thermal method with alternative energy sources other than natural gas represents a good direction for further exploration of oil sands resources.

Table 4.1 Comparison of bitumen production using open pit mining method and in situ steam-assisted gravity drainage method

Factor	**Mining**	**SAGD**
Overburden depth	<75 m	>150 m
Reserves (totals 27 billion m^3; 170 billion bbl)	20 %	80 %
Crude bitumen production (total 238,000 m^3/d, 1,500,000 bbl/d -2009)	55 %	45 %
Recovery	>90 %	<60 %
Fresh water demand (m^3/ m^3 bitumen)*	2–3	~0.5
Carbon imprint (kg CO_2e/ m^3 SCO)	820	1,100
Direct land disturbance (ha/100,000 m^3)	5.9	0.88
Capital cost	high	moderate

*from Allen (2008) and Syncrude Canada Ltd. (2007) for mining, and Flint (2004) for in situ, respectively.

4.5 Bitumen Upgrading

4.5.1 Current Technology

Bitumen is a sticky, tar-like mixture of millions of molecular species consisting mainly of highly condensed polycyclic aromatic hydrocarbons. Compared with conventional and heavy oils, the main characteristics of bitumen are relatively large molecular weight, lower hydrogen to carbon ratio, and higher sulphur, nitrogen and metal content (Table 4.2).

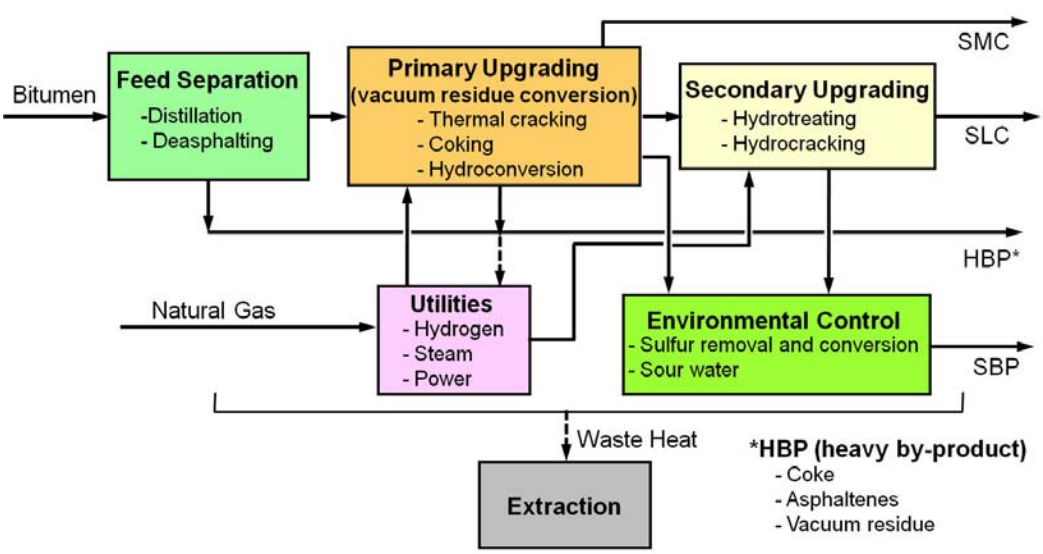
The viscous bitumen with high asphaltene content cannot be directly processed by refineries designed for conventional crude oil. Therefore bitumen needs to be upgraded to SCO before it is processed in downstream refineries to produce gasoline and diesel fuel. The purpose of bitumen upgrading is to reduce the density, viscosity and molecular weight, increase the hydrogen-to-carbon ratio, and partially remove sulphur, nitrogen, and heavy metals from crude bitumen. To accomplish these tasks, bitumen upgrading essentially includes a two-stage chemical-physical treatment: primary upgrading followed by secondary upgrading (Figure 4.13). The ultimate goal of bitumen upgrading is to increase its market value by producing a higher value SCO.

Table 4.2 Comparison of typical physical-chemical properties of bitumen and upgraded SCO with those of conventional crude

Property		**Bitumen**	**Conventional Crude**	**SCO**
Density at 16 °C (kg/m^3)		1000	860	870
API gravity		10	32	31
Viscosity (mPa s)	15°C	235,000	14	19
	40°C	1,050	9	10
Boiling range (°C)		250 to >800	30 to 550	50 to 560
Carbon content (wt%)		84	84	85.5
Hydrogen content (wt%)		10.5	13.5	13.5
Sulphur content (wt%)		4.0	1.9	0.3
Nitrogen content (wt%)		0.42	0.09	0.05
Nickel content (ppm)		69	14	<1
Vanadium content (ppm)		190	3.7	<0.6
Hydrocarbon composition		**wt%**		
Saturates		30	80	22
Aromatics		70	20	78
Asphaltenes*		10	<1	<1

*measured on the basis of hydrocarbons, but included in aromatics.

Figure 4.13 A generic upgrading scheme with SMC for sour medium crude, SLC for sweet light crude, and SBP for sulphur by-product



Source: Figure courtesy of Murray Gray, adapted with permission

4.5.1.1 Feed Separation

When coking is used as primary upgrading, the bitumen is first treated by vacuum distillation to separate overhead light hydrocarbon off gas, liquid gas oils, and heavy vacuum residue from each other. The light hydrocarbon off gas is used mostly as fuels in the subsequent bitumen upgrading, while liquid gas oils are treated in the downstream secondary upgrading. The vacuum residue is fed to the coker for thermal cracking. In primary upgrading without coking and deasphalting in the froth cleaning, it is beneficial to remove heavy polyaromatic asphaltenes prior to primary upgrading by hydroconversion. This is necessary as asphaltenes are highly prone to coke formation. The formed coke particles are most likely to deposit on hydroconversion catalysts, rapidly deactivating them. Deasphalting, when employed, is accomplished by a similar approach as used in paraffinic froth cleaning, i.e., controlled precipitation of asphaltenes by paraffinic solvent addition, producing de-asphalted bitumen for primary upgrading by hydroconversion. The asphaltenes by-product could be an energy source for upgrading and steam generation using gasification technology.

4.5.1.2 Primary Upgrading

Regardless of technologies (coking vs. hydroconversion) used in primary upgrading, the objective of primary upgrading is to break down large molecules and increase hydrogen content of the liquid product, particularly to break down polyaromatic hydrocarbon molecules. The secondary upgrading focuses on removal of sulphur and nitrogen without significant further conversion to lighter products. (Flint 2004)

Coking has been a predominant process for primary upgrading. In coking, vacuum distillation residue is fed as a fluid to a coker where large hydrocarbon molecules are cracked at temperatures of 430–550 °C. Two main technologies are used: delayed coking where the heat of reaction is provided by burning fuel gas, and fluid coking where a portion of the product coke is burned. In both cases, the valuable product from the coker is an overhead vapour containing naphtha and light and heavy gas oils, which are further upgraded in secondary upgrading processes. Operated at a relatively lower pressure, coking is a mature technology involving lower capital and operating cost than other upgrading technologies. Coking produces solid coke as a by-product, currently with little market value in northern Alberta. The fluid coking process also produces a combustion gas (N_2+CO_2+CO+H_2S) which is incinerated in a boiler to produce heat needed for utility, extraction, and upgrading operations. Instead of being stored as a solid waste, future operations could use coke as a source of energy in gasification to produce hydrogen for upgrading and heat for extraction and utility.

Hydroconversion as an alternative technology for primary upgrading not only cracks large hydrocarbon molecules, but also adds hydrogen to the cracked molecules, partially converting aromatics to cycloparaffins. In hydroconversion, hot bitumen and hydrogen are combined as a single feed stream to a reactor where bitumen is reacted with hydrogen through catalytic reactions at a relatively low temperature of <460 °C but at relatively high pressure (up to 200 atm). The hydroconversion produces naphtha and various cuts of gas oils. The unreacted hydrogen in the gas product stream from hydroconversion is separated and recycled back to the reactor, with remaining hydrocarbon tail gas being used as fuel gas. The liquid product (condensates of overhead hot gas) is

fractionated and sent to various secondary upgrading units for hydrotreating. Compared with coking as the primary upgrading method, hydroconversion results in a high yield of liquid product without producing a solid waste product, but it does produce heavy residue which needs to be further treated by coking at the upgrader or used in gasification/co-generation for steam and electricity generation.

In some operations, both coking and hydroconversion are used in primary upgrading in which low value heavy residue from the hydroconversion is fed to the coker for thermal upgrading. With aggressive primary upgrading by fluid coking in this configuration, a desulphurization process is added to remove sulphur content from flue gases.

4.5.1.3 Secondary Upgrading

Since the purpose of primary upgrading is to reduce the molecular weight and partially break down large molecules, the secondary upgrading uses hydrogen gas to remove sulphur, nitrogen, and oxygen, and to hydrogenate polyaromatic and olefin molecules. Secondary upgrading is accomplished by hydrotreating in catalytic reactors at elevated temperature and pressure. Different reactors and catalysts are used for different cuts of the oil stream from the primary upgrading. The hydrotreaters are operated at temperatures < 400 °C, converting most organic sulphur compounds to H_2S (and hydrocarbons) with greater than 90% conversion and nitrogen to ammonia with greater than 70% conversion. Metallic elements in bitumen are mostly captured either in the coke product of the primary upgrading or on the spent catalyst surface of hydroconversion. They do not enter the secondary upgrading units.

The treated gas oils and naphtha products from secondary upgrading are blended to form SCO. The physical-chemical properties of SCO are given in Table 4.2. A close look at these properties reveals that the SCO from upgrading of bitumen is of much lower sulphur, nitrogen, and metal content than conventional crude oil, while the other physical-chemical properties are comparable. Bitumen upgrading (primary and secondary) does not significantly reduce total aromatic content in the resultant SCO. Instead, bitumen upgrading converts poly aromatics in raw bitumen into mono-, di-, and tri-aromatics. The SCO produced from bitumen is of higher quality for refineries in some of its properties such as its low sulphur and nitrogen content and lack of large molecules compared with conventional crude oil.

4.5.1.4 Hydrogen Production

Hydrogen is an essential reactant in both primary upgrading by hydroconversion and secondary upgrading by hydrotreating. At present, all but one oil sands operation uses natural gas as the source for producing hydrogen. In hydrogen production from natural gas, the sulphur in the natural gas is first converted to hydrogen sulphide (H_2S) by hydrogen addition and the resultant H_2S is removed by gas separation unit and converted to elemental sulphur. The desulphurized natural gas is catalytically reacted with steam to produce a raw hydrogen gas stream containing hydrogen, CO, and CO_2. The hydrogen in this stream is separated from other gases by pressure swing absorption, producing high purity hydrogen. The tail gas produced is used as fuel while CO is converted to CO_2. In some cases, the CO in the raw hydrogen stream is further reacted with steam to produce more hydrogen and CO_2, generating a hydrogen stream containing a trace amount of CO and CO_2 which are catalytically

converted back to methane. The light hydrocarbons in this hydrogen stream are removed as condensate which is used as fuel for heat and steam production. The high quality hydrogen produced is compressed and sent to bitumen upgraders for hydroconversion and hydrotreating.

While producing hydrogen from natural gas or by gasifying asphaltene/coke by-product of bitumen froth cleaning and primary upgrading, electricity is generated for overall oil sands operations. As noted in Figure 4.13, the excess low quality thermal energy (waste heat) generated by upgrading is used in bitumen extraction. A natural consequence of generating hydrogen from natural gas or gasification of petroleum coke and asphaltenes is a significant contribution to overall GHG emissions. To achieve a target CO_2 reduction of 25% from baseline emissions in 2012, hydrogen generation using a combination of oxyfuel and steam reforming with CO_2 capture is required (Tarun et al. 2007; Ordorica-Garcia et al. 2010).

4.5.1.5 Sour Water Treatment and Flue Gas Cleanup

During upgrading, gas separation uses hot water as a separating medium. Inevitably, it produces sour water containing H_2S and ammonia. These contaminants in the sour water are stripped off by a fractionation process, producing acid gas, ammonia vapour, and treated water. After removal of contaminants, the water is further treated before it is returned to the plant for oil sands processing. The NH_3 vapour, after further removal of contained H_2S, is either incinerated or removed in a desulphurization unit. The H_2S, separated from the product of hydroconversion and hydrotreating, is converted to elemental sulphur by downstream reactors (oxidation by air, followed by catalytic conversion). Overall, more than 99% of H_2S is converted to elemental sulphur as a stable by-product which is currently stockpiled. The heat from liquid sulphur condensation is used to produce steam. Whenever coke is burned as a fuel, the sulphur in the form of SO_2 in the flue gas is captured by desulphurization units producing either ammonium sulphate ($(NH_4)_2SO_4$) or gypsum ($CaSO_4$) as a by-product. The ammonium sulphate can be used potentially as fertilizer, while the gypsum can be used as an additive in the CT process described above or sent to landfill.

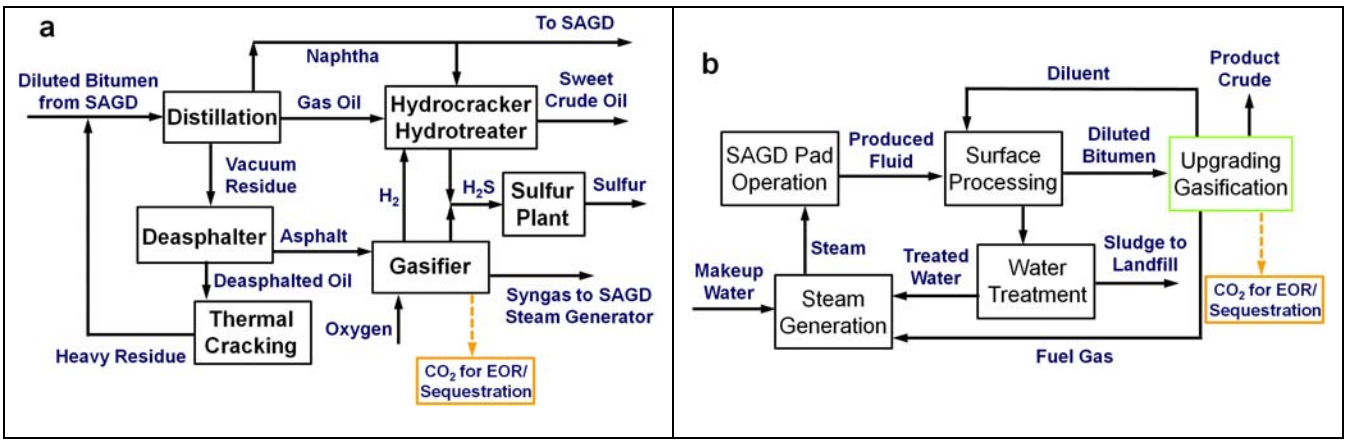
4.5.2 Emerging Technology

4.5.2.1 Integration of Upgrading with Bitumen Production by In Situ SAGD Method

The physical-chemical nature of bitumen makes upgrading necessary, whether it is done in Alberta or elsewhere. Upgrading bitumen in Alberta allows it to be integrated with bitumen production by either mining or in situ methods, and with CCS, enhanced oil recovery (EOR), or in situ bitumen production of deep oil sands formations. Upgrading in Alberta also brings substantial economic activity into the province. In upgrading, more than 28.3 m^3 (1,000 SCF) of hydrogen need to be added to produce 0.16 m^3 (1 bbl) of SCO. Producing this volume of hydrogen consumes about half of the total natural gas consumed during upgrading. The other half is used to generate thermal energy required for distillation, coking, and cracking reactions. An alternative to reduce the dependence of current upgrading technology on natural gas is to use the waste of bitumen extraction (asphaltenes) and upgrading (cokes) as the energy and hydrogen source through integration of upgrading with gasification as described below.

In an integrated process, diluted bitumen (dilbit) from the SAGD operation is combined with the product (heavy residue) of downstream thermal cracking units (Figure 4.14a). The mixed stream is distilled first at atmospheric pressure. A part of the liquid product, mainly naphtha is recycled back to SAGD above-ground operations, while the remaining part is further treated by downstream hydrotreaters. The resultant bitumen product of atmospheric distillation is processed by vacuum distillation to remove light hydrocarbons and gas oils that are further processed in downstream hydrotreating. The vacuum distillation residue is deasphalted by using paraffinic solvent to remove low value polyaromatic asphaltenes and coke in the product stream of thermal cracking. The asphaltenes and coke containing most of the sulphur of the bitumen are gasified in the presence of steam to produce hydrogen for hydrotreating and CO used for steam generation by combustion. The steam generated is used for bitumen production by SAGD (Figure 4.14b). The H_2S in the gas stream of gasification is treated in a sulphur plant to produce elemental sulphur as a by-product. At the same time, a CO_2-rich gas stream is produced, which can be used for EOR or CO_2-assisted bitumen production. A unique feature of this integrated process is that it does not use natural gas to produce hydrogen for upgrading and steam for SAGD. The upgrading operation maximizes the value of its own waste, such as asphaltenes and coke as alternative energy source. This integrated process remains at the demonstration stage, producing around 4,000 m^3 (25,000 bbl) SCO daily.

Figure 4.14 Schematic processes of an integrated upgrading/gasification system (a) with SAGD operations (b)



Source: Figure courtesy of Murray Gray, adapted with permission

The short-term objective of the oil sands industry remains focused on improving the energy intensity of current bitumen production and upgrading technologies, and on integrating bitumen production with upgrading to reduce the energy and hydrogen dependence on natural gas by utilizing the by-products of bitumen extraction (asphaltenes) and upgrading (coke). Although it does not reduce overall GHG production, the rich CO_2 produced at point source by gasifiers can be captured and stored safely or used in EOR or in deep formation bitumen production. A recent report showed an attainable maximum reduction of CO_2 emissions by 25% and 39% of the business-as-usual baseline in 2012 and 2030, respectively, if carbon capture in hydrogen and power plants supplying the oil sands industry is implemented (Ordorica-Garcia et al. 2010). Analysis has shown that implementing CCS can reduce the life-cycle GHG emission to 25% of current systems and process GHG emissions to zero by co-

utilization of fossil fuels and biomass (Bergerson and Keith 2010), but CCS will not be implemented by the oil sands industry without a financial incentive (McKellar et al. 2010). A recent study also showed potential to improve energy efficiency of SAGD by 20% through cost effective practical measures, contributing significantly to reduction of CO_2 emissions (Du Plessis and Buchanan 2010).

4.5.2.2 In Situ Upgrading

For deeper deposits that allow in situ extraction, in situ upgrading offers to eliminate mining, extraction, tailings management, steam generation/injection, and current above-ground primary upgrading, while reducing fresh water and natural gas usage. Oil sands resource exploration by in situ upgrading is extremely attractive, in concept, but unfortunately implementation remains in the distant future. The thermal energy produced by in situ combustion of bitumen would be used as the energy source for thermal cracking of bitumen in deep oil sands formations (Xia et al. 2003). While less viscous lighter hydrocarbons produced are lifted above ground for further hydrocracking and/or hydrotreating, CO_2 produced from bitumen combustion could be stored in the bitumen-exhausted formation.

The concept of in situ combustion to provide the needed thermal energy for bitumen production was tested at Alberta Research Council and Alberta Ingenuity Centre for In Situ Energy at University of Calgary (Chow et al. 2008). The promising toe-to-heel air injection (THAI) process (Xia et al. 2003; Xia and Greaves 2006; Shah et al. 2010), initially considered as an in situ bitumen production method, is currently under field pilot evaluation for in situ bitumen upgrading and lighter hydrocarbon production. THAI integrates in situ combustion and upgrading with horizontal well production. The combustion gas (air) is injected in a vertical well placed in the top layer of the oil sands formation, while the horizontal production well is placed close to the bottom of the oil sands formation as in SAGD. As combustion of bitumen in the oil sands formation progresses to reach the toe of the production well, heated bitumen at the immediate front of the combustion zone starts to flow along the heated oil sands formation, in a manner similar to the steam chamber of SAGD, into the horizontal production well from the toe to the heel. Bitumen recovery as high as 75% is estimated for THAI because of the efficient sweep of the reservoir by the combustion front and hot gas drive. Compared with operating temperatures of 250 °C in SAGD, the higher operating temperature from 500 to 700 °C created by combustion in THAI in the oil sands formation causes partial in situ upgrading of bitumen by thermal cracking (coke rejection). Laboratory model tests showed that such a condition produces oil of 70% saturates by thermal cracking of aromatics, 50 to 500 mPa.s viscosity at 15 °C and greater than 16° API gravity as compared with API values of 10° and 32° for bitumen and conventional crude oil, respectively. This API value, as a measure of oil quality, is almost double the API value of the original bitumen (Xia and Greaves 2002; Greaves et al. 2008). While mobilized and cracked lighter oil is drawn down to the production well, the heavy residue left behind in the reservoir is either burned off to generate thermal energy or cracked to light oil and coke. The coke generated by this thermal cracking is consumed by combustion.

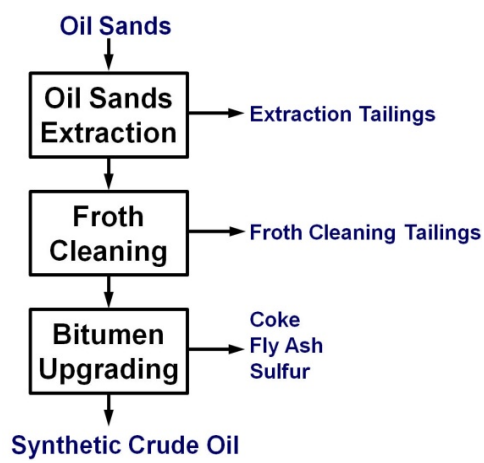
The in situ thermal cracking of bitumen in THAI could be further improved by introducing a sheath of catalysts around the horizontal production well, known as the CAPRI^{TM} process, producing an upgraded bitumen of above 22° API gravity. A challenge to THAI commercialization is to achieve a

controllable combustion front temperature and velocity. Since thermal energy to mobilize and upgrade bitumen is provided by in situ combustion of coke and heavy residues, bitumen production by THAI does not need steam from surface facilities, substantially reducing GHG emissions and the use of natural gas. Bitumen in situ upgrading is currently limited to only demonstration production (Greaves et al. 2008). A considerable effort has been made in laboratory studies to explore the possibility of in situ catalytic upgrading of bitumen, but so far with very limited and slow progress.

4.6 By-products from Oil Sands Processing

Developing oil sands resources not only produces liquid fossil fuels that are in-demand, but also generates a number of by-products including oil sands tailings, petroleum coke, and elemental sulphur. These by-products are produced at various stages of oil sands processing as shown in Figure 4.15(Oxenford et al., in press). A plant producing 16,000 m^3/d (100,000 bbl/d) SCO will need to process roughly 200,000 t/d oil sands ores, generating 50,000 m^3/d coarse sands, 20,000 m^3 MFT (or 40,000 m^3 fluid fine tailings), 2,000 m^3/d petroleum coke, 600 m^3 sulphur/d and 100 m^3/d fly ash (Majid and Sparks 1999). Some of these by-products, such as oil sands extraction tailings, are considered industrial waste of environmental concern, while the others, such as froth treatment tailings, elemental sulphur, and petroleum coke, have potential to be used as raw materials with economic value. The following is a brief summary of the value of these oil sands processing by-products.

Figure 4.15 By-product produced during oil sands processing and bitumen upgrading to SCO



Source: adapted from Oxenford et al. (in press)

4.6.1 Oil Sands Extraction Tailings

Oil sands extraction tailings are clearly the largest waste stream of oil sands development. The majority of solids (<75%) in oil sands extraction tailings are coarse solids. Although coarse solids contained in oil sands tailings have little economic value, they settle quickly and do not cause difficult environmental challenges. Coarse sands are often deposited to build dykes of tailings ponds for containment of fluid fine tailings.

Fine solids contained in extraction tailings, on the other hand, have been a major concern because of their extremely slow settling and consolidation. Decades may be required to consolidate fluid fine

tailings to above 30 wt% solids. Continuing generation of fluid fine tailings requires containment in tailings ponds to hold the MFT which trap a significant amount of water. Remediating MFT represents one of the major environmental challenges to the oil sands industry. However, some of the fine solids in MFT have potential economic value. Effort has been made to extract residual bitumen for production of SCO, clean kaolinite as paper coatings, and metakaolin as additives for Portland cement. Residual hydrocarbons contained in MFT could be as high as 2–3 wt%, and can be recovered by advanced flotation technology or mechanical attrition by hydrophobic beads or petroleum cokes. Although commercial recovery of hydrocarbon as a stand-alone operation may not be attractive, incentives to reduce the potential environmental impact of methane produced by biodecomposition of entrained hydrocarbon in tailings ponds have led to recent research and development efforts on developing a viable technology for recovering these entrained hydrocarbons from MFT. Removing hydrocarbon from MFT may also facilitate separation of valuable kaolinite and metakaolin from MFT.

The solids of a typical MFT contain as high as 23 wt% kaolinite, 17 wt% illite, 25 wt% mixed clays (both kaolinite-smectite and illite-smectite), and 30 wt% quartz, with around 4 wt% iron-containing minerals (Omotoso et al. 2006). Although it is attractive to recover kaolinite as a value-added by-product from oil sands mature or fluid fine tailings, producing the final product of required properties appears to be extremely challenging because of the ultra-small sizes and bitumen-contaminated nature of fine kaolinite particles. To be used for paper making, for example, the kaolinite produced should contain as little silica and other clay minerals as possible while having high brightness and opacity. Ideally, recovered kaolinite should have particle size between 0.2 to 2 microns to achieve desired light scattering. A combination of centrifugation, selective flocculation followed by sedimentation or hydrocyclone separation, and acid bleaching has been attempted to produce kaolinite of the required specifications.

Unfortunately, the product obtained by a combination of these methods still contains impurities of iron oxide and quartz higher than allowed because of their detrimental impact on paper making. At laboratory scale, application of high gradient magnetic separation in combination with hydrocyclone and bleaching as practiced in the clay industry successfully removed residual hydrocarbons and iron-containing minerals from MFT to obtain kaolinite of tailored particle size and desired aspect ratio (Omotoso and Hamza 2001). The product has comparable properties to commercial coating grade kaolinite clays for paper-making applications. The eventual commercialization of kaolinite extraction for paper making and pigment manufacture is largely dictated by economics and market demand for clays.

Kaolinite contained in oil sands MFT can be calcined at dehydroxylation temperatures (550 °C) to metakaolin which can be used as a pozzolan supplement for concrete mixes (Zhang and Malhotra 1995). Although oil sands MFT contain less than 23 wt% kaolinite, the high specific surface area and the presence of kaolinite-smetite mixed clays make MFT worthwhile as a raw material to be calcined to produce metakaolin quality cement additives. The calcined solids in oil sands MFT (CMF) are suitable as a partial replacement for Portland cement up to 20%, providing improved compressive and flexural strengths and resistance to aggressive de-icing chemicals, freeze-thaw, and chloride penetration (Wong et al. 2004). The CMF provide a low cost option to cement production at a reduced

CO_2 footprint of Portland cement production. Unfortunately, the commercial production of CMF for the cement industry depends largely on the demand of local construction activities, as transportation from Fort McMurray to larger markets is a major cost constraint. Consequently, calcination of solids in oil sands MFT for cement production is unlikely to be a major contributor to reducing the inventory of oil sands MFT.

4.6.2 Froth Cleaning (Treatment) Tailings

The tailings from froth cleaning (treatment) make up about 2% of total oil sands tailings. A unique relatively small size of solid particles and relatively high amount of hydrocarbons, in particular for the tailings from paraffinic froth cleaning. A typical paraffinic froth cleaning tailings contains as high as 5 wt% hydrocarbons in the form of asphaltene precipitates and trapped solvents, 20% solids, and 75% water. The inorganic solids in a froth cleaning tailings are made up typically of 40% silica sand, 30% clays, and 30% heavy minerals. More specifically, inorganic solids in froth cleaning tailings contain typically 1.5–4.2% ZrO_2, 7.3–13.7% TiO_2, 44–56% SiO_2, 6.8–12.8% Al_2O_3, 9.2–11.4% Fe_2O_3, 1.5–3.4% CaO, 1.5–1.6% MgO, 0.16–0.25% MnO, 1.0–1.5% K_2O and 0.3–0.5% Na_2O, all by weight (Liu et al. 2006). These solids are substantially contaminated by hydrocarbons and therefore are hydrophobic. For paraffinic froth cleaning tailings, the solids also contain a substantial amount of asphaltene precipitates.

Although they are a small fraction of the total tailings, the high hydrocarbon content in froth cleaning tailings makes it attractive to recover hydrocarbon from these tailings streams. Considerable effort has been dedicated recently to searching for viable technologies for effectively recovering hydrocarbons (including solvent and organic precipitates) from froth cleaning tailings. Agglomeration separation of hydrocarbons by petroleum coke (Majid and Sparks 1999) has been attempted, showing promising results. In a recent laboratory study, column flotation (Thomas et al. 2010) was effective in recovering more than 80% of contained hydrocarbons. The recovered hydrocarbons were amenable for further cleaning using standard bitumen froth cleaning technology. Therefore, the recovered hydrocarbons can be combined and cleaned together with bitumen froth from oil sands extraction. Alternatively, recovered hydrocarbons (mainly asphaltenes) can be used as low quality fuels in gasifiers for co-generation of steam, electricity and hydrogen, as practiced in the integrated in situ bitumen production process. Removing hydrocarbons from froth cleaning tailings also reduces overall hydrocarbon content of total oil sands tailings, reducing their environmental consequences. Recovery of hydrocarbon from froth cleaning oil sands tailings is being field tested to explore its commercial potential.

The heavy minerals, mainly titanium (11% TiO_2) and zirconium (3–4%) in the froth cleaning tailings can be potentially recovered as marketable minerals. In fact, the titanium content in the froth cleaning tailings represents the second richest among titanium ores around the world, while the production of zircon would be the first of its kind in Canada. More importantly, these heavy minerals are highly liberated and there is no need for comminution as practiced in the mineral industry, which is extremely energy intensive. After removal of organic contaminants by attrition, a combination of magnetic/electrostatic separation and flotation have been demonstrated at pilot scale tests to produce marketable rutile (up to 89% TiO_2) as a feedstock for TiO_2-based pigment production and zircon (65%

ZrO_2 and 1.2% Hf) (Oxenford et al., 2011). The successful commercialization of recovering heavy minerals from oil sands froth cleaning tailings depends on market demand.

4.6.3 By-products from Bitumen Upgrading

4.6.3.1 Coke

Coke is a major by-product when a coker is used in primary upgrading. The majority of coke is currently stockpiled as a waste by-product. Unfortunately, most heavy elements contained in bitumen are enriched in petroleum coke which poses long-term stability concerns with stockpiling. A typical petroleum coke contains 1,680 ppm vanadium, 500 ppm nickel, 13 ppm arsenic, and 1.5 ppm selenium, among other regulated trace elements. A systematic study on leachability of stockpiled petroleum coke using EPA's Toxicity Characteristics Leaching Procedure (TCLP) revealed a negligible release of these regulated elements and volatile organics under severe leaching conditions of pH 2 (Chung et al. 1996; González et al. 2009). For the elements with the highest concentrations, vanadium and nickel, their concentrations in the leachate were determined to be 0.26 and 0.04 ppm, respectively, confirming that these elements are essentially nonleachable from by-product coke. These metals appear to be locked inside the carbon matrix in a manner that they are not accessible by water and long-term stockpiling of the petroleum coke should not allow for heavy metal leaching. However, longer term monitoring of metal release from petroleum coke is advised to ensure safe stockpiling of the petroleum coke.

Despite the high heating value (30 MJ/kg) of petroleum coke, its high sulphur content (6–9%) and low volatile matter content (low reactivity) make it less attractive as fuel source for boilers, although some of it is consumed in co-generation by gasifiers to produce steam, hydrogen, and electricity in one oil sands operation. A recent review indicated that an entrained gas gasifier is capable of effectively gasifying petroleum coke, leading to an acceptable gasification rate at gasifier temperatures of 1500 °C (Furimsky 1998; Cousins et al. 2008). In gasification, sulphur contained in the coke becomes less of an issue as it is mainly converted to H_2S and subsequently to elemental sulphur as a by-product. Biomass and petroleum coke co-gasification would improve the reactivity of feedstocks, but is rather limited by the availability of suitable biomass in the region. The limitation on a wider use of this by-product rests on the cost for co-generation facilities and maturing of CCS technology for CO_2 sequestration.

Petroleum coke from bitumen upgrading can also potentially be used as additives for enhanced consolidation of oil sands fluid fine tailings, carriers for hydrocarbon recovery from oil sands tailings by liquid agglomeration technology, ingredients of road construction, and raw materials for manufacturing activated carbon used in organic removal from industry effluents or oil sands tailings water or as a sorbent for flue gas clean-up. In the long term, petroleum coke will become a valuable by-product rather than a waste of bitumen upgrading.

4.6.3.2 Sulphur

Elemental sulphur is considered a commodity material mainly for the production of fertilizers. Because of the relatively remote location of oil sands operation sites, the sulphur produced during bitumen upgrading is mainly stockpiled in large blocks of hundreds of metres in length and width, which are

constructed to reduce dusting and the surface area available for oxidation (Rappold and Lackner 2010). Although there is little reported on the environmental consequences of stockpiling elemental sulphur in oil sands regions, elemental sulphur is considered flammable and could potentially lead to sulphur fires. Exposure of elemental sulphur to air and moisture provides energy for the metabolism of certain bacteria. Oxidation of elemental sulphur on the surface of blocks and cracks to sulfates is inevitable (Birkham et al. 2010), leading to seepage of acidic water of pH 0.4 to 1 from the base of sulphur blocks. The seepage water flows through a clay-lined ditch to a run-off sump where the seepage water is neutralized and pumped to tailings pond for further neutralization by the tailings pond water.

Developing a sulphur-based product for local or regional consumption is important. Efforts have been made to develop sulphur concrete for constructing haul roads for heavy duty trucks (Abraha et al. 2007). In open pit mining oil sands operations, there is a need to use alternative road construction materials to provide a smooth, rut-free riding surface for efficient mining operations without incurring additional cost. Laboratory results show that the concrete made from sulphur mixed with fly ash and tailings sand is much stronger and stiffer than the existing materials for building heavy duty truck haul roads. The leaching tests on sulphur concrete showed little chemical reaction and degradation under or near surface conditions, indicating minimal impact of sulphur concrete haul roads on the nearby environment. The rut-free surface of sulphur concrete roads not only ensures smooth driving of heavy duty trucks, but also significantly reduces fuel consumption, reducing emissions from haul trucks.

4.6.3.3 Fly Ash

Fly ash is produced only when petroleum coke is combusted by a coke burner to generate heat for oil sands processing and bitumen upgrading. Although it represents a small fraction of solid wastes, fly ash at a 90,000 tonne/year production rate captures the majority of vanadium and nickel. In addition to a substantial level of nickel (1%), titanium (1.7%), molybdenum (0.2%) and iron (5.2%), the fly ash from bitumen coke combustion contains 3–6% V_2O_5, which is five times higher than the grade of vanadium concentrate treated in recent years in South Africa and Australia for primary vanadium production (Holloway and Etsell 2005). Extracting vanadium from this fly ash would account for approximately 3.6% of total world vanadium production. Fortunately, the metal elements in this fly ash are not amenable to acid leaching (Majid and Sparks 1999), making it safe for long-term disposal by landfill if economics do not allow recovery of the metals.

Considering the vast resource of vanadium in the fly ash from bitumen coke combustion, extensive research has been devoted to investigating technologies to recover vanadium from this fly ash. A process concept diagram for complete utilization of oil sands fly ash was recently developed by Holloway and Etsell (2005). To produce vanadium metal from oil sands fly ash, the ash is first decarbonized at 500–600 °C for 6–8 hours to remove the remaining carbon. The resultant ash product is then roasted with 20–30% salt (NaCl) at 850–900 °C for 2–3 hours, converting vanadium in the ash to soluble form. Hot water leaching of the calcined fly ash at 95 °C for one hour leads to a vanadium extraction of 75–85%, producing a leachate containing 27–42 g/L vanadium. After removal of silicon by precipitation at alkaline solution of pH 10–11, ammonium chloride is added to the concentrated pregnant leach solution to precipitate ammonium metavanadate (NH_4VO_3). The NH_4VO_3 precipitates

are dewatered by filtration and calcined at 500 °C to produce V_2O_5 containing >97% V_2O_5, <1% SiO_2 and <0.2% Na. The product with this composition is suitable for marketing.

During roasting-leaching, about 50% of the minor element molybdenum is leached from the roasted ash and remains in solution during vanadium precipitation. With addition of ammonium sulphide $(NH_4)_2S$), molybdenum in leachate is recovered as molybdenum sulphide which can be further calcined to marketable MoO_3. The small volume solid residues, after harsh leaching treatment, are considered stable for safe long-term disposal (Holloway and Etsell 2005), although their long term stability remains to be established (Blowes et al. 2003).

4.6.4 Summary of By-products

Clearly various by-products from oil sands processing and bitumen upgrading, although often considered as environmental liabilities, have the potential to serve as a natural resource. Their development to commercially competitive operations and market products depends largely on market demand, transportation to the marketplace and competitive availability of these resources from other traditional sources. While developing new markets for these by-products, long term monitoring of acid production and leachability of metals from various by-products should be practiced and the data made available.

4.7 Oil Sands Technology Advances

Since the first commercial operation of oil sands by Great Canadian Oil Sands in 1967, technology has advanced significantly, not only to improve operation performance, but also to address environmental impacts such as reducing the use of fresh water by recycling and reduction of energy intensity and hence lower GHG emissions by lowering the severity of process operating conditions (e.g. temperature). Technological advances have contributed to increased recoverable oil sands reserve estimates by increasing bitumen recovery efficiency. However, the industry strives to further improve the energy intensity, reduce GHG emissions by using alternative energies and processes with minimum GHG emission or ones amenable for CCS, reduce fresh water intake by improving process water treatment and recycling, eliminate tailings ponds by generating stackable tailings and reclaim the disturbed land, and monitor long term environmental impact of various by-products and stackable tailings. The collective efforts of governments, academia, and the oil sands industry to achieve further advances in oil sands technologies (both bitumen production and upgrading) aim to make the oil production from oil sands, known as technology oil (Isaacs 2005), more environmentally friendly and competitive economically. Because society has no viable alternative to liquid hydrocarbon fuels for decades into the future, the oil sands reserve in Northern Alberta will remain strategically important for some time. Technology must continue to improve to serve those demands while resolving the major environmental constraints that are reviewed in Part 2 of this report.

The Alberta government and industry have invested in excess of $1 billion each in oil sands research and $2 billion in carbon capture and storage technology (Gov AB 2010).

5 REGULATORY FRAMEWORK FOR OIL SANDS DEVELOPMENT

5.1 Canadian Constitutional Division of Powers

The Constitution of Canada grants authority to the federal government for peace, order and good government along with various specified areas of jurisdiction. For any area of jurisdiction not explicitly assigned to provincial legislatures, the so-called residual powers are assigned to the federal government. The relevant specific powers granted to the federal government are:

- subsection 91(2) granting exclusive federal jurisdiction over trade and commerce including inter-provincial and international trade including export of crude oil, oil and gas pipelines, and transport across provincial and international boundaries,
- subsection 91(10) granting exclusive federal jurisdiction over navigation (navigable waters), and
- subsection 91(12) granting exclusive federal jurisdiction over inland fisheries.

Because the majority of bitumen extracted from Alberta oil sands projects is destined for export to other provinces or other countries, the federal government has significant authority over the commercial exploitation of the oil sands under the first area of federal jurisdiction. Given the major involvement of water in oil sands projects, the latter two areas of federal jurisdiction provide substantial scope for federal involvement in regulating environmental aspects of oil sands development.

Relevant specific powers granted to the provincial government are:

- subsection 92(5) granting exclusive provincial jurisdiction over the management and sale of public lands,
- subsection 92A(1) granting exclusive provincial jurisdiction over exploration development, conservation, and management of non-renewable natural resources within a province.

The foregoing specific provisions have had the effect to date of making the Province of Alberta the primary regulator of oil sands development, including being the major regulator of environmental requirements, with additional regulatory authority residing with the federal government.

The reality is that the federal and provincial governments have concurrent jurisdiction over the environment. Environment is not mentioned explicitly in the Constitution and both levels of government can pass laws with regard to environmental matters. Where federal and provincial governments occupy the same field, any conflicts are dealt with by the rule of paramountcy—meaning where there is an operational conflict, the federal government legislation will prevail. In practice, there has been considerable experience with co-operative federalism whereby provinces and the federal government will adopt bilateral agreements to address concurrent jurisdiction.

Under this division of constitutional powers, the Canadian and Alberta governments have a number of statutes which provide specific regulatory provisions governing oil sands development and operation.

5.2 Federal Regulatory Authority

5.2.1 Legislation with Approval Provisions

Based upon the constitutional authority assigned to the federal government, the primary relevant laws that may require specific approvals from a federal agency are the Fisheries Act (FA), the Navigable Waters Protection Act (NWPA), and the Migratory Birds Convention Act (MBCA). Such approvals may also invoke the Canadian Environmental Assessment Act administered by the Canadian Environmental Assessment Agency (CEAA). The requirements of these federal acts and some others which are occasionally involved in oil sands are elaborated explicitly in Appendix A3.

Surface mining oil sands operations are almost certain to include activities that will involve authorizations under the Fisheries Act and the Navigable Waters Protection Act because landscape disruption caused by these projects will typically affect fish habitat and impact navigable waters. The scope of such developments has typically been sufficient to attract a federal interest in environmental assessment (CEAA) which would normally be conducted jointly with Alberta under the cooperative agreement with Alberta which has been in place since 1999 and was updated in 2005.

5.2.2 First Nations Industrial Approvals

Some bitumen reserves exist under lands held in trust for First Nations by the federal Crown. The federal government currently does not have a regulatory regime specifically designed to address oil sands mining activities. The Province of Alberta has an extensive, comprehensive regulatory regime for oil sands mining, as will be outlined below, but the provincial regulatory regime does not apply on reserve lands. On First Nations land, federal regulations are needed to create regulatory certainty and to effectively manage environmental, health and safety, and other related impacts of the proposed oil sands mining project, and thereby enable the leasing of the lands for oil sands development (Gov Canada 2007). In September 2003, members of Fort McKay First Nation voted to accept a Treaty Land Entitlement settlement agreement to designate lands containing mineable crude bitumen (oil sands) to be added to the Fort McKay First Nation reserve lands and to be able to lease these lands for the purpose of exploiting the oil sands reserves to the benefit of Fort McKay First Nation. These lands can only be leased for development of the oil sands if "*a regulatory regime is established...sufficient to protect the interests of the First Nation, its members, the environment, and Her Majesty.*" Consequently, the Fort McKay First Nation Oil Sands Regulations were enacted to allow adoption of the provincial regulatory regime for these purposes.

5.2.3 Aboriginal Consultation

CEAA has acknowledged that the Supreme Court of Canada has ruled that the Crown has a legal duty to consult Aboriginal peoples, and where appropriate to accommodate, when the Crown has real or constructive knowledge of the potential existence of Aboriginal rights or title, and the Crown contemplates possible conduct that might adversely affect those rights, whether those rights have been

established (proven in court or agreed to in treaties) or whether there is only the potential for rights to exist (Gov Can 2008).

5.2.4 National Pollutant Release Inventory (NPRI) Reporting

Owners or operators of facilities that meet specified requirements must report to the NPRI authorized by the Canadian Environmental Protection Act (CEPA 1999), subsection 46(1). Failure to comply with the requirements for submission of the data or reports by the deadline (June 1 of the following year) carries substantial penalties, a maximum fine of $1,000,000 or imprisonment of a responsible official for up to three years or both.

If one or more substances listed in the annual NPRI notice was manufactured, processed, or otherwise used at a facility in the calendar year, and the facility exceeded a threshold of approximately 10 full-time employees, the facility must determine the total amount of each NPRI substance at the facility during that calendar year and report as required by the annual NPRI reporting notification.

5.2.5 Climate Change and Greenhouse Gas Emissions Control

The Canadian government established a program for reporting greenhouse gas (GHG) emissions in March 2004. Under the authority of Section 46 of the Canadian Environmental Protection Act, 1999 (CEPA 1999) operators of facilities that meet the criteria specified in an annual published notice are required to report annual facility GHG emissions to Environment Canada by June 1st of the following year.

Since the introduction of the GHG reporting program, any Canadian facility emitting over 100,000 tonnes of CO_2 equivalent (CO_2e)[10] GHGs in a given calendar year has been required to report the amount of GHGs emitted. In 2009, the minimum value for reporting was reduced from 100,000 tonnes to 50,000 tonnes CO_2e thereby including more GHG emitters.

[10] An important consideration when reporting greenhouse gas emissions is to calculate the emissions based on carbon dioxide equivalent (CO_2e) values. Each greenhouse gas has its own unique properties, which will affect how long it will remain in the atmosphere and its potential to trap heat (Gov Can 2010a). In order to compare the emissions of greenhouse gases, a factor known as global warming potential is used to convert all gases to CO_2e values. For example, based on the Specified Gas Reporting Standard, the total emissions for an oil sands facility in a given calendar year should be calculated by:

$$E_{Total} = \sum_{i=1}^{n}(E_{CO_2,i} \times G_{CO_2}) + \sum_{i=1}^{n}(E_{CH_4,i} \times G_{CH_4}) + \sum_{i=1}^{n}(E_{N_2O,i} \times G_{N_2O})$$

where:

E_{Total} = the total carbon dioxide equivalent (CO_{2e}) tonnes of GHG emitted by an oil sands facility in a given calendar year
E_{CO2}, E_{CH4}, E_{N2O} = tonnes of CO_2, CH_4, and N_2O emitted
G_{CO2}, G_{CH4}, G_{N2O} = the global warming potential multiplier of CO_2 (1), CH_4 (21), and N_2O (310), respectively
i = each individual source of emissions
n = number of emissions sources

5.3 Provincial Regulatory Authority

5.3.1 Sale of Mineral Rights

The oil sands deposits in Alberta are primarily located on Crown land which means that mineral rights to the bitumen reside with the provincial Crown (97% of Alberta's 140,000 square kilometers of oil sands are on provincial Crown land). Any organization seeking to extract bitumen from these deposits must obtain a permit or lease from the provincial government in a competitive bidding process and pay royalties to the provincial government once production has commenced (Section 11.1).

5.3.2 Access to Public Lands

Gaining approval for access to public lands is required both for exploration and for operations. Owning oil sands rights, which must be purchased from the Province, is not a prerequisite to seeking access for exploration purposes but ultimately, the oil sands rights must be acquired before the Province will grant access to commence operations towards commercially recovering bitumen.

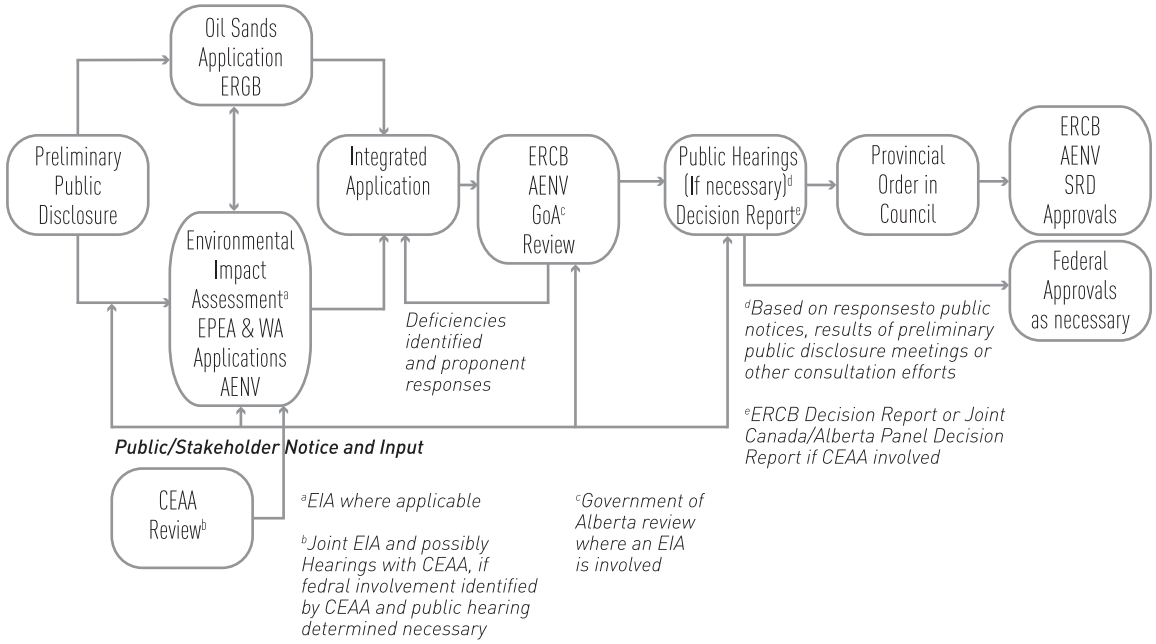
The regulatory process for gaining access to public land for oil sands exploration approval for oil sands in Alberta is managed by Alberta Sustainable Resource Development (SRD). Granting surface rights for oil sands operations is administered by SRD under the Public Lands Act (PLA) and the Surface Rights Act (SRA). An oil sands development on public lands will require issuance of surface dispositions such as a mineral surface lease (MSL), a license of occupation (LOC), surface material dispositions, or a pipeline agreement.

5.3.3 Project Review (Public Interest Determination and Environmental Assessment)

The ERCB has been granted exclusive jurisdiction in Alberta over oil sands development and conservation by the Oil Sands Conservation Act (OSCA). Under this jurisdiction, construction or operation of any development to recover bitumen from oil sands is prohibited without ERCB approval. An oil sands developer may make a preliminary application for a project that the ERCB will review and determine whether the proponent can proceed to a full application for approval under the OSCA in accordance with ERCB Directive 23.

Figure 5.1 provides a simplified overview of the various components of the regulatory process that applies to oil sands operations. Normally, the application will include an Environmental Impact Assessment (EIA) prepared by the proponent if the project is subject to mandatory environmental assessment according to regulations under the Environmental Protection and Enhancement Act (EPEA) or for any project that the responsible Director of Alberta Environment (AENV) decides requires an EIA. Mandatory projects include oil sands mines and/or any oil sands, heavy oil extraction, and upgrading or processing plant producing more than 2000 m^3 (12,600 bbl/d) of crude bitumen per day.

Figure 5.1 Simplified overview of oil sands regulatory process.



In unusual cases, if there is any question of the need for an EIA for a project that is not subject to a mandatory assessment, the EIA process requires the proponent to submit a Project Summary Table to the Director to allow a determination of the need for an EIA.[11] If the Director determines that an EIA is not required (only for projects not subject to mandatory assessment), the proponent can apply for the necessary environmental approvals. Alternatively, the Director may determine that more information is required which will be accomplished by the Director preparing a screening report. This requirement also includes a disclosure document to notify the public, providing a minimum 30-day public comment period, of a project that the AENV Director will screen for the purposes of determining the need for an EIA. When the Director has made this determination, the screening report is made public and the proponent is advised whether an EIA report is required.

The practice that has emerged in the oil sands industry involves development of terms of reference (ToR) by AENV. Through the review process, specific questions and requests for additional information are addressed to project proponents by regulators and other interested parties. These can lead to more submissions from proponents before the EIA report is considered final.

The public must be notified about the nature of a proposed oil sands project at various stages of the regulatory process. If the project proceeds to an application for approval by the ERCB, that board must determine whether there is a need to hold a public hearing. In cases where the federal government has declared a need for both an EIA under CEAA and for public hearings to be held, a joint federal-provincial review panel will be called under the 2005 Canada–Alberta co-operative agreement.

[11] Environmental Assessment Program, EA Guide 2008-1, Alberta's Environmental Assessment Process Updated February 2010. http://environment.gov.ab.ca/info/library/6964.pdf accessed 15 April 2010.

Although public involvement is a cornerstone of the project review process, the ERCB can exclude public interest groups and other stakeholders related to the impacts of oil sands development from participating in the process and, ultimately, from participation at a hearing.

Only those stakeholders that the ERCB determines to be relevant to a development will be considered for intervener status.[12] As Vlavianos (2007) notes with respect to a case in 2007: "*Along with standing to participate fully, the issue of costs is equally important. Ever since the affected municipality and health authority were denied costs for their involvement in three recent oil sands mining applications, one wonders whether these parties will have the resources to become as involved in future applications.*"

The ERCB is charged with making an overall "*public interest*" determination regarding any application for oil sands development. If the ERCB decides to recommend the application, subject to whatever conditions it deems appropriate, that recommendation is made through the Minister of Energy to the Alberta Cabinet which holds the ultimate authority to approve a project, but only if the ERCB recommends it to Cabinet. The ERCB also functions as a regulator of oil sands operating and abandonment procedures.[13]

Vlavianos (2007) notes: "*it is difficult to define concretely what is meant by public interest and how the board will apply consideration of this interest in any given situation.*" In practice the Board weighs

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[12] AR 252/2007, Energy Resources Conservation Board – Rule of Practice

24(1) A person who wishes to intervene in a proceeding shall file a submission and serve a copy of it on the other parties within the time set out in the notice of hearing.

(2) A submission must be in writing and contain the following:

(a) a concise statement indicating

(i) the manner in which the intervener's rights may be directly and adversely affected by a decision of the Board on the proceeding,

(ii) the nature and scope of the intervener's intended participation,

(iii) the disposition of the proceeding that the intervener advocates, if any,

(iv) the facts the intervener proposes to show in evidence,

(v) the reasons why the intervener believes the Board should decide in the manner that the intervener advocates, and

(vi) the intervener's efforts, if any, to resolve issues associated with the proceeding directly with the applicant;

(b) the name, address in Alberta, telephone number, fax number and, if available, e-mail address of the intervener;

(c) if the intervener is represented by a representative, the and, if available, e-mail address of the representative;

(d) if the intervener is an unincorporated organization, the nature of the intervener's membership.

(3) The Board may, on receiving and examining a submission, do one or more of the following:

(a) direct the intervener to serve a copy of the submission on such other persons and in such a manner as the Board specifies;

(b) direct the intervener to provide additional information to the Board;

(c) direct the applicant or the intervener to make further submissions, either orally or in writing, on the original submission;

(d) decide that the intervener will not be heard because

(i) the submission is frivolous, vexatious or of little merit, or

(ii) the intervener has not shown that the decision of the Board in the proceeding may directly and adversely affect the intervener's rights;

(e) if the Board is of the view that any matter set out in the submission is not in response to the application or has implications of importance beyond the application, direct a revision of the application or the submission that the Board considers necessary.

[13] from OGCA s. 1(1)(a) "abandonment," subject to section 68(a), means the "permanent dismantlement of a well or facility in the manner prescribed by the regulations and includes any measures required to ensure that the well or facility is left in a permanently safe and secure condition."

the benefit of a specific project with any risks or costs associated with that project. The environmental impact assessment (EIA) is used by the ERCB in its determination of whether the project is in the public interest and in setting its own approval terms and conditions.

In recent years, the Government of Alberta (primarily AENV and SRD) have not been participating directly in the public hearings of the ERCB, as was the normal practice in the past. The absence of participation by these environmental agencies raises concerns about the degree to which the ERCB decision-making panel is fully apprised of important environmental issues that should bear on the public interest decision.

The ERCB is charged with regulating virtually every aspect of the planning and operation of an oil sands facility (mining, in situ, and bitumen upgrading operations), including most factors related to residuals and waste management. There is also considerable regulatory authority governing oil sands operations vested in AENV and SRD, so the respective responsibilities of the regulators are covered by a Memorandum of Understanding (MoU) among these three agencies.

AENV has considerable regulatory authority to develop site-specific EPEA and Water Act (WA) approvals that are required to allow oil sands developers to operate. Approvals for operations are issued for up to 10 years under EPEA to govern a large number of very specific environmental management issues. The purpose and intent of EPEA is expressed in Section 2 of the Act as:

The purpose of this Act is to support and promote the protection, enhancement and wise use of the environment while recognizing the following:

(a) the protection of the environment is essential to the integrity of ecosystems and human health and to the well-being of society;

(b) the need for Alberta's economic growth and prosperity in an environmentally responsible manner and the need to integrate environmental protection and economic decisions in the earliest stages of planning;

(c) the principle of sustainable development, which ensures that the use of resources and the environment today does not impair prospects for their use by future generations;

(d) the importance of preventing and mitigating the environmental impact of development and of government policies, programs and decisions;

(e) the need for Government leadership in areas of environmental research, technology and protection standards;

(f) the shared responsibility of all Alberta citizens for ensuring the protection, enhancement and wise use of the environment through individual actions;

(g) the opportunities made available through this Act for citizens to provide advice on decisions affecting the environment;

(h) *the responsibility to work co-operatively with governments of other jurisdictions to prevent and minimize transboundary environmental impacts;*

(i) *the responsibility of polluters to pay for the costs of their actions;*

(j) *the important role of comprehensive and responsive action in administering this Act.*

Much of what is under debate about the environmental footprint of oil sands operations relates to the expressed purposes of EPEA. Implementation of this legislation to achieve the purposes stated in EPEA in a consistent, committed, and rigorous manner for oil sands development would certainly address many environmental concerns which have recently been expressed.

Water use and developments affecting surface or groundwater involve the proponent making water license, permit, and approval applications to AENV under the Water Act. The purpose and intent of the WA is expressed in Section 2 of the Act as:

The purpose of this Act is to support and promote the conservation and management of water, including the wise allocation and use of water, while recognizing

(a) *the need to manage and conserve water resources to sustain our environment and to ensure a healthy environment and high quality of life in the present and the future;*

(b) *the need for Alberta's economic growth and prosperity;*

(c) *the need for an integrated approach and comprehensive, flexible administration and management systems based on sound planning, regulatory actions and market forces;*

(d) *the shared responsibility of all residents of Alberta for the conservation and wise use of water and their role in providing advice with respect to water management planning and decision-making;*

(e) *the importance of working co-operatively with the governments of other jurisdictions with respect to trans-boundary water management;*

(f) *the important role of comprehensive and responsive action in administering this Act.*

As with EPEA, implementing the WA in a manner that achieves these stated purposes in a consistent, committed, and rigorous manner for oil sands development would certainly address many concerns which have been expressed about water management.

Under EPEA, the construction, operation and reclamation of oil sands mines and processing plants require an approval issued by AENV. EPEA approvals typically have clauses for air quality, water quality, waste management, conservation and reclamation, soil salvage and placement, annual conservation and reclamation reporting. Oil sands approvals issued in 2006 and 2007 have more comprehensive soil salvage and placement requirements than was previously specified. Older approval clauses will remain until the approvals are renewed (within 10 years). The approval covers special reporting and plan approval related to reclamation research, tailings reclamation, end pit lakes,

wetlands reclamation, and coke and sulphur management. Reclamation materials balance tracking, reclamation security, and remediation and reclamation certification are responsibilities of AENV.

Bitumen upgrading produces coke and sulphur as residuals. These are regarded as resources by the ERCB, so storage must be managed to facilitate future resource recovery. AENV is concerned with coke and sulphur storage to minimize environmental impact (i.e., leachate runoff, sulphur dust, etc.) but also recognizes a potential role for coke in oil sands reclamation.

Storage, disposal, and handling of oil wastes from in situ oil sands projects are regulated by the ERCB. Sites for managing oily wastes at mining operations are regulated by the ERCB with regard to need, location, design, and performance while AENV must approve associated land disturbance and reclamation as part of the overall reclamation plan.

Regulation of sulphur recovery and control of sulphur dioxide emissions at bitumen upgrading facilities involve considerable overlap between the ERCB and AENV. ERCB specifies sulphur recovery requirements for oil sands operations making it necessary to monitor sulphur recovery efficiency and perform mass balances. Other processing operations regulated by ERCB (fluid coking and coke-fired boilers) will affect sulphur dioxide emissions. However, AENV is responsible for specifying emission limits for sulphur dioxide from all sources and for specifying emissions monitoring requirements. Consequently, ERCB and AENV must work closely together to ensure that the objectives of both regulators are met and are consistent.

Compliance monitoring and on-site surveillance is managed jointly by the ERCB, AENV, and SRD. ERCB has primary responsibility for operating issues regarding resource recovery, energy efficiency, and product management. AENV has primary responsibility for overall environmental performance, environmental impacts, emissions, and compliance with approvals under EPEA and WA.

A major emergency requires an operator to immediately implement its site-specific emergency response plan with the ERCB taking a lead role in judging the technical problems causing the emergency; AENV is engaged to ensure that appropriate environmental monitoring and protection is implemented. SRD conducts conservation and reclamation inspections and monitors compliance with dispositions issued under PLA. Occupational health and safety and public health agencies are also engaged as appropriate.

AENV takes the lead in dealing with public odour complaints and coordinating local and regional mechanisms for following up and resolving odour complaints by tracking sources and working with industry to identify and mitigate odour sources.

Liquid spills of unrefined hydrocarbons (crude bitumen, condensate, diluent, synthetic crude, or produced water) are initially managed by the ERCB with their field staff responsible for ensuring containment and recovery of any spilled materials and proper disposal of any wastes generated. AENV is responsible for ensuring operators minimize and mitigate any adverse environmental effects from such spills and for containment and recovery of any refined products (fuels) and chemical spills.

Flaring is a joint regulatory responsibility between the ERCB and AENV. ERCB is responsible for resource conservation (energy value) aspects and AENV is responsible for environmental impacts, such as those linked to sulphur dioxide and other emissions.

Continuous emission monitors and stack surveys are primarily a regulatory responsibility of AENV which specifies requirements, monitors performance, and ensures accuracy of measurement. ERCB is interested in sulphur balance and sulphur recovery from processes.

Tailings ponds and dam safety regulation are jointly administered by the ERCB and AENV. Reviews of the conceptual planning and preliminary engineering design of tailings ponds are performed by the ERCB. Applications for construction of tailings ponds are governed under the WA and the Dam Safety Regulations. The ERCB and AENV coordinate approvals for abandonment of tailings ponds, but AENV sets the reclamations standards to be achieved for tailings ponds.

Alberta was the first province in Canada to legislate land reclamation in 1963. Reclamation was initially associated with oil and gas activities, such as well sites and pipelines, but was broadened to cover mines, including oil sands mines. AENV required conservation and reclamation plans prior to granting of approval for development of an oil sands mine. In 1978, requirements to salvage and store soil were introduced. In 1993, EPEA and the Conservation and Reclamation (C&R) Regulation were enacted to replace previous legislation. ERCB has a responsibility to consider reclamation under its public interest mandate so the ERCB works with AENV on reclamation issues with the proponent, and both agencies seek to make decisions that are consistent with each other.

Conditions associated with operator liability, after reclamation is certified, are described in EPEA and associated regulations. For an oil sands mine, operator liability for reclamation ceases upon issuance of a reclamation certificate. For an oil sands processing plant, operator liability for reclamation ceases 25 years after issuance of a reclamation certificate. For all sites, the operator remains liable for contamination in perpetuity. Financial security issues for reclamation are discussed in Section 11.3.

Once an oil sands mine is approved by the ERCB and AENV, the PLA dispositions issued by SRD will authorize the use of public land and regulate the operator's vegetation removal, aggregate management, and some conservation and reclamation activities. Removal and use of forest resources from the project area during development is regulated under the Forests Act, which also provides direction for reforestation during reclamation.[14] The Forest and Prairie Protection Act regulates fire control planning and provides support for participation in coordinated firefighting efforts. SRD provides direction on mitigation and other measures to support sustainability of wildlife, fisheries and fish resources as mandated under current regulations, policies, the Wildlife Act, and the Fisheries (Alberta) Act, and monitors management strategies and practices which support requirements set for wildlife and fish resources. SRD provides field inspectors delegated under EPEA to verify compliance with EPEA approval clauses, assess compliance, and provide direction on final land use expectations and requirements for post-reclamation landscapes and land units.

[14] Surface rights are separate from mineral (or sub-soil) rights. Much of the oil sands area in the province are also contained in areas covered by Forestry Management Agreements (FMA), which assign timber harvest rights to the FMA-holder, thereby making FMA-holders important and economically-engaged stake-holders in oil sands development.

A PLA disposition is only granted after the project receives approval under EPEA. Annual reports are reviewed for operational compliance and inspections are conducted specific to individual operators and key reclamation activities. Once reclamation is complete and monitoring information is available for a period of time, industry may apply for a reclamation certificate and transfer responsibility for the condition of the land back to the Government of Alberta.

5.3.4 Climate Change and Greenhouse Gas Emissions Control

Alberta was the first jurisdiction in Canada to regulate GHGs with the Climate Change and Emissions Management Act (2003) and associated regulations. These require direct emitters of more than 100,000 tonnes of CO_2e in 2003 or later to report emissions and reduce their GHG emission intensity relative to their baseline GHG emissions.

Emissions intensity limits have been established by the Alberta government relative to baseline emissions which existing facilities have established or new facilities must establish during their first three years of operation. For existing facilities, the baseline intensity was established by averaging 2003, 2004, and 2005 emissions values. Emission restrictions are calculated using these baseline intensities. For example, in 2007 and 2008, established facilities were not to exceed 88% of their reported baseline emissions (Gov AB 2007a). A new facility's intensity limit varied between 90% and 98%, based on the year of commencing commercial operation. If a facility is unable to meet these standards, it is required to offset its emissions by purchasing fund credits (at the rate of $15 per tonne of CO_2e emitted, with the amount paid into a Climate Change and Emissions Management Fund dedicated to support research into emissions reduction), or use emission offsets or performance credits (transferring an extra reduction in emissions from another separate facility to achieve credit for the facility not in compliance).

5.3.5 Aboriginal Consultation

In May 2005, the Government of Alberta adopted the Government of Alberta's First Nations Consultation Policy on Land Management and Resource Development, wherein Alberta makes the commitment to consult with First Nations where land management and resource development have the potential to adversely impact First Nations rights and traditional uses of Crown lands.

The Government of Alberta now has a Ministry of Aboriginal Relations and the Premier and Minister of Aboriginal Relations both signed a Protocol Agreement on Government to Government Relations with the Treaty 6, 7, and 8 First Nations in May 2008. The Protocol Agreement states general principles and records the intentions of the Parties but does not create any legal rights or responsibilities or legally binding obligations on the rights of the Parties. The Protocol Agreement calls for the Grand Chiefs and the Ministers responsible for consultation with First Nations regarding land and resource development to meet twice a year to discuss matters pertaining to Alberta's policy and guidelines on consultation, and other subjects where agreed.

Alberta released its original First Nations Consultation Guidelines on Land Management and Resource Development in September 2006, with the current revised Guidelines being adopted, following stakeholder consultation, in November 2007 (Gov AB 2007). These Guidelines state:

The duty to consult rests with the Crown (Alberta). While the key goal in all circumstances is to avoid or mitigate potential adverse impacts and to come to an agreeable solution, the agreement of all parties is not a requisite component of adequate consultation.

In some cases, consultation may reveal a duty to accommodate for the Crown to meet in making its decision. Accommodation can mean efforts to reconcile, adjust, or adapt. In that regard, it will be reflected in the regulatory approval process, which will take into account the efforts of project proponents to address First Nation concerns by making changes to plans and adjusting and adapting projects to minimize impacts.

5.3.6 Public Health

The Public Health Act (PHA) in Alberta authorizes the Chief Medical Officer to recommend to provincial Cabinet to declare a public health emergency for a variety of hazards including the presence of a chemical agent that poses a significant risk to the public health. The PHA is paramount over all other provincial legislation except for the Alberta Bill of Rights. While chemicals are included in this authority, the concept of a public health emergency is more confidently based upon communicable disease epidemics. Substantial confidence in imminent danger would be required to declare a public health emergency over a chemical threat. Such confidence would be difficult to have, even in a precautionary sense, for typical environmental exposures. A possible example that might warrant a public health emergency would be a substantial and ongoing release of hydrogen sulphide in circumstances that imminently threaten a populated area given the well-established knowledge base on the health risk of high levels of hydrogen sulphide.

Further elaboration of how public health issues are handled under the environmental impact assessment process is found in Section 10.4 and 11.4.2.

5.4 Compliance and Enforcement

AENV has a reasonably rigorous enforcement track record in recent years with 19 environmental convictions and six ongoing prosecutions under EPEA or WA since 2007. Over this period, AENV has issued 46 Administrative Penalties, 7 Enforcement Orders, and 19 Environmental Protection Orders (AENV 2010).

The ERCB has maintained a reputation with the oil and gas industry of being a rigorous inspector and enforcer and it publishes a monthly report of enforcement actions (ERCB 2010a). The last published annual report of compliance and enforcement actions covered the 2007 calendar year (ERCB 2008a). Given the dispersed nature of the conventional oil and gas industry, the ERCB Public Safety and Field Surveillance Branch conducted 16,408 inspections in 2007 (up from 14,860 in 2006).

Mineable oil sands operations were handled separately by the Oil Sands Section of the Fort McMurray ERCB Regional Office which conducted 18 audits / inspections in 2007 with 94% rated as satisfactory and 6% unsatisfactory (but categorized as low risk). The staff in this office was increased to 42 which enabled the ERCB to more than triple the number of inspections (each can take up to one week) and site visits conducted in 2008 at mineable oil sands facilities over the 2007 number (ERCB 2010b).

ERCB Oil Sands Section staff responded to 37 reportable incidents (including spills and releases) in 2007. They also worked with AENV staff in preparing an Environmental Protection Order in response to ground-level exceedances of ambient air quality objectives. The ERCB issued a detailed directive concerning inspection and compliance for oil sands mining and processing plants in December 2008 (ERCB 2008b).

5.5 Issues of Concern Regarding the Oil Sands Regulatory Process

5.5.1 Regulatory Capacity to Deal Effectively with Oil Sands Development

The pace of development of oil sands projects has placed heavy demands on the regulatory capacity of the Alberta and Canadian governments. At a time when the regulatory capability of the relevant agencies needs to be optimized to deal with the diverse environmental challenges involved, the number and complexity of development proposals has created an unprecedented challenge. A deficiency in regulatory capacity at AENV and SRD and the need for improving regulatory capacity was identified in the comprehensive review provided by the Radke Report (Gov AB 2006) which noted:

Departments lack capacity to complete Environmental Impact Assessments (EIAs), to complete technical studies such as those involving instream flows, to focus on cumulative effects and to develop policy in a timely fashion. In addition, capacity to monitor and enforce environmental requirements is inadequate. One effect of this lack of resources will be the eventual inability on the part of the Province to deal with new applications for oil sands development in a timely way, and thus cause a delay in oil sands development itself. Another impact will be inadequate attention to cumulative effects and other issues raised by oil sands development.

The Radke Report (Gov AB 2006) addressed this need by recommending:

A substantial increase in manpower (FTEs) should be provided to Alberta Environment and Alberta Sustainable Resource Development to focus on cumulative effects, EIAs, research, policy development, monitoring and enforcement in the oil sands areas. Some new resources should also go to Alberta Health and Wellness to support the EIA process.

The extent to which this recommendation for expanded resources at AENV and SRD has been fulfilled is not clear in any of the evidence reviewed by the panel. Judging whether the recommendation has been fully implemented would be difficult in any case because the Radke Report did not define "*substantial increase*." The expansion of the ERCB field office in Fort McMurray and resulting substantial increased capacity for inspections of oil sands mining operations was noted in Section 5.4.

The ERCB is the primary regulator which must make the public interest recommendation to the Alberta Cabinet. In its previous form as the Energy and Utilities Board (EUB)[15], it experienced a serious incident damaging its public credibility as an independent quasi-judicial board.[16]

[15] The Energy and Utilities Board (EUB) was created in 1995 by merging what had previously been the ERCB and the Public Utilities Commission thereby providing the new EUB with a massive responsibility for making public interest project decisions and regulating activities across the oil, gas, electricity, and other utility sectors.

Because of this incident, a new acting Chair was appointed to the EUB to implement recommended changes and oversee the splitting of the EUB into the ERCB and the Alberta Utilities Commission effective January 1, 2008. The acting chair also disbanded the EUB Security Unit, accepted the resignation of the EUB senior executive in charge of security and revoked the EUB decisions which had been made on this file. The process was sent back to begin anew under a new hearing panel. Acting EUB Chair, Dr. William Tilleman, stated:

This EUB decision is the equivalent of a mistrial. Albertans must be confident that this board acts fairly, responsibly and in the public interest. Mistakes have been made on this file and I believe the only way to re-establish public confidence is to go back to square one on this process.

The nature of and response to this incident, although not involving an oil sands project, demonstrated the importance of assuring that the quasi-judicial board responsible for making the public interest determination on oil sands projects and recommendation to the Alberta Cabinet not only consistently acts in a manner which fully respects the principles of natural justice, but can also be reliably perceived to do so.

The capacity of AENV, SRD, and the ERCB to respond to the technical demands of issuing approvals for the large number of new oil sands developments has been a concern. Technical and scientific resources in Alberta over the past decade have been under heavy demand by developers and their consultants. AENV, SRD, and ERCB have experienced retirement or departure of a number of senior staff in the past decade and recruitment of younger replacement staff has occurred in a highly competitive market place. Meanwhile, there has been an evident trend to replace senior staff with generic managers rather than providing a career progression path for qualified technical specialists within these agencies. Given the complexity of environmental issues being raised by oil sands developments, senior bureaucrats and political decision-makers need to be advised by scientifically and technically skilled senior staff to a greater degree than is currently evident.

The regulatory capacity among federal agencies has been more difficult to assess, partly because federal agencies have maintained a very low profile regarding oil sands developments. As the profile of environmental concerns regarding the oil sands has become national and international in scope, it is unlikely that the role of federal regulatory agencies can remain as low in profile as it has been. This is particularly important for matters involving Canada's international commitments such as the management of GHG emissions.

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[16] In response to a major, coordinated, and extensive disruption of a hearing regarding a major power transmission line in April 2007, the EUB Security Unit hired a private security firm to provide plain-clothes personnel to attend future hearings. One of these security personnel established rapport with members of a group opposing the development and was invited to participate in conference calls of that group. The investigator received approval from the EUB security manager to participate in, covertly, but not to record, these calls. The stated purpose of this covert action was to learn if future disruptions were being planned.

When allegations of EUB "spying" on the public opposition group became public, formal investigations were launched by the Information and Privacy Commissioner (Mun 2007) and by a retired Court of Queens Bench judge (Perras 2007) into the actions of the EUB. Justice Perras (retired) described the authorization by the EUB of the actions of the private security member to participate in the conference call on behalf of the EUB as "repulsive."

5.5.2 Reactive vs. Preventive Environmental Management

Although it is essential to have a vigorous compliance and enforcement program to deal with failures to meet environmental criteria, it is clearly important that the environmental regulatory program achieve prevention of problems. Vigorous enforcement conveys a deterrent message to operators that they will be prosecuted if they fail, but equally important is the need to ensure that all reasonable measures are taken to prevent environmental problems. The EPEA approvals issued by AENV provide the main vehicle for requiring that effective measures are taken to prevent environmental contamination problems. The designated Director (EPEA) is the technical specialist (with his or her team of AENV technical staff) who must write the EPEA approvals. To assure the integrity of EPEA, this exercise must be done free of any direct or implied political pressure from the Minister or any senior management of AENV. Effective approvals can only be assured if the designated Director and supporting technical staff have the expertise and experience necessary to write approvals which achieve the objectives of EPEA.

There has been an evident trend in EPEA approvals over the past decade for so-called milestone clauses which delay many details of what an approval requires to the future discretion of the AENV Director, in response to submissions from the approval holder (AEAB 2008). Approvals are issued for 10 years so there clearly does need to be some flexibility to deal with matters which will arise over the life of an approval, although amendments are commonly requested and issued. However, if approval conditions are left too general, without adequate specification of the necessary outcomes and adequate field inspection of actual performance, the preventive capacity of approvals may not be achieved. If AENV does not develop and maintain the inhouse expertise for writing effective approvals, free of any political or senior management pressue, the objectives of EPEA will not be achieved.

A recent serious failure by an oil sands operator occurred in the notorious case involving the gruesome death by oiling and drowning of over 1,600 ducks on a Syncrude tailings pond in April 2008. The approval holder's failure in this case may suggest an inadequate preventive capability, leaving only a less satisfactory reactive enforcement remedy by AENV.

This disaster of killing so many ducks in such an objectionable manner has become a compelling international icon for lax environmental management in the oil sands. Syncrude was prosecuted under both EPEA and MBCA and has been found guilty in Provincial Court. The defence argued that the EPEA and MBCA charges were both for the same offence so that the case was adjourned prior to sentencing to allow arguments to be heard on this issue. The defence also argued that it was wrongly charged under EPEA because it was authorized by the Government of Alberta to operate the tailings pond where the ducks were killed. The hazardous bitumen froth which killed the ducks was not released to the environment as implied by the charges, rather it was contained in the authorized tailings pond. Counsel for Syncrude argued at the trial that a properly placed charge would have been based on EPEA Section 227 which specifies an offence for contravening a term of an approval. In the case of preventing harm to waterfowl, the applicable sections of the Syncrude approval were:

6.1.76 The approval holder shall submit a Waterfowl Protection Plan to the Director by December 31, 2007, unless otherwise authorized in writing by the Director.

6.1.77 The Waterfowl Protection Plan referred to in 6.1.76 shall include:

(a) techniques and procedures for a comprehensive bird deterrent program for all tailings, composite tailings and waste ponds which minimizes avian mortality from the ponds;

(b) a comprehensive program for monitoring and documenting avian mortality, timing of incidents, and bird species affected; and any other information as required in writing by the Director.

6.1.78 The approval holder shall implement the Waterfowl Protection Plan referred to in subsection 6.1.76 as authorized in writing by the Director.

The incident in question occurred in late April 2008 and it was not clear in arguments made at trial whether the Director[17] had authorized the Waterfowl Protection Plan (WPP) as contemplated in clause 6.1.78 to require implementation of the WPP before the incident occurred. Regardless, until that plan was authorized by the Director, this part of the approval fails to unambiguously oblige Syncrude to implement a WPP. Clearly, preventing this incident would have been far preferable to any subsequent legal action. A more explicit requirement for a WPP in the Syncrude approval might have contributed to more effective preventive measures by Syncrude.

After the adjournment, Syncrude changed its defence counsel and eventually negotiated a guilty plea with the prosecution under which Syncrude was fined the maximum for a single incident: $300,000 for the federal charge and $500,000 for the provincial charge. Syncrude also agreed to donate $1,300,000 for research into bird migration and the effectiveness of bird deterrents at the University of Alberta and $900,000 for the Alberta Conservation Association to purchase and preserve a wildlife habitat area. Half of the $500,000 provincial fine was allocated to the environmental program at Keyano College in Fort McMurray to train Aboriginal students in monitoring waterfowl.

Only about a week after this case was settled, another incident occurred on another Syncrude tailings pond which appears to have resulted in the deaths (mostly by euthanizing ducks in distress) of over 350 additional ducks. This incident was still under investigation at the time this report was being completed, so a full explanation remains to be determined and further charges may be pending. Unlike the April 2008 incident, other tailings ponds in the region at Suncor and Shell also experienced ducks landing in tailings ponds and becoming oiled in what have been described as particularly unusual and extreme weather conditions (freezing rain). These incidents have been very damaging to the stated position of oil sands operators and government regulators that the negative environmental consequences of oil sands development can be acceptably managed. Some technical aspects of this situation are discussed in Section 8.2.2.1.

5.5.3 Government of Alberta Commitment to Environmental Protection

As if the duck deaths were not damaging enough, the apparent commitment of the Government of Alberta to meaningful environmental protection has been further damaged by public statements from two senior Cabinet Ministers questioning the importance of Syncrude being prosecuted for this environmental disaster (Audette 2010). The Premier had to take the unusual step of issuing a statement

[17] In this context, the Director is a designated official at AENV.

that these two senior Ministers did not speak for the Government of Alberta on this matter. Given that one of the Ministers who spoke against the Syncrude prosecution was and is currently Minister of Energy, to whom the ERCB reports, the credibility of the Government of Alberta on environmental management has been further damaged. This level of dysfunction in government communications coming from senior Cabinet Ministers is difficult to understand given that Government of Alberta has allocated $25 million of taxpayers' money to counteract "inaccurate" international portrayals of Alberta's management of oil sands impacts (Anon 2008). Certainly, this communication incident is wholly inconsistent with the commitments made by the Government of Alberta in its own commitment to Responsible Actions (Gov AB 2009) and it raises serious questions about the motivation of the Cabinet Ministes involved towards environmental responsibility.

5.5.4 Non-Participation of AENV and SRD in Public Hearings

In recent years the practice whereby AENV and SRD have not been participating in the ERCB public hearings means that the ERCB must make its public interest decision without the benefit of public input from Alberta's primary environmental regulators. AENV and SRD, in turn, are faced with issuing environmental approvals, licenses, and authorizations (EPEA, WA, PLA) to projects that have been approved by the ERCB without the benefit of publicly accessible AENV and SRD input at the hearing stage. In the case of AENV approvals, this practice of non-participation would appear to open the door to making a credible case for appealing those approvals to the Environmental Appeals Board (EAB) by parties who can satisfy the EAB that they are directly affected. The EAB is required by its enabling legislation (EPEA) to dismiss appeals of approvals for which it determines that:

"*...the person submitting the notice of appeal received notice of or participated in or had the opportunity to participate in one or more hearings or reviews under…any Act administered by the Energy Resources Conservation Board…at which all of the matters included in the notice of appeal were adequately dealt with.*" (EPEA, 95(5)(b)(i))

A directly affected person would have to convince the EAB that the matter they wish to appeal before the EAB had not been adequately dealt with. In past practice where AENV participated fully in ERCB public hearings on projects which dealt widely with environmental issues, this test was challenging. Under the recent practice of non-participation by AENV, it is conceivable that matters appearing in EPEA or WA approvals or licenses issued by AENV could be deemed by the EAB not to have been "*adequately dealt with*" at the ERCB hearings. In any case, the determination of whether the matter in question has been "*adequately dealt with*" is determined by the EAB, not the ERCB.

In the case of projects which undergo a CEAA Review, the test for the EAB to exercise jurisdiction is somewhat more stringent, requiring the EAB to dismiss an appeal if:

"*the Government* [of Alberta] *has participated in a public review under the Canadian Environmental Assessment Act (Canada) in respect of all of the matters included in the notice of appeal*." (EPEA, 95(5)(b)(ii))

5.5.5 Regulatory Approval of Projects in the Public Interest

In addition the concerns raised above related to lack of participation by relevant government agencies in the environmental assessment and review process, there are a number of concerns about the adequacy of the environmental impact assessment (EIA) process which are discussed in Section 11.4.

Main Report Part 2

PART 2 MAJOR ENVIRONMENTAL AND PUBLIC HEALTH ISSUES

6. GREENHOUSE GAS (GHG) EMISSIONS

6.1 Introduction

As we noted in Section 1.1, we have taken as an important fact that Canada has made international commitments to reduce GHG emissions. Our review does not attempt to address any of the broader questions or implications of climate change associated with GHG emissions because the scope and complexity of those issues are well beyond the scope of what our panel could adequately address while doing justice to reviewing the considerable range of evidence dealing directly environmental and health impacts of oil sands development.

Removing bitumen from oilsands and upgrading bitumen are generally energy intensive processes, which result in substantial emissions of GHGs such as carbon dioxide (CO_2). The oil sands industry is the second largest direct CO_2 emissions contributor in Alberta so reducing the quantity of GHGs directly emitted by this industry is an essential element of an overall GHG emissions strategy for Alberta and Canada.

6.2 Greenhouse Gas Emission Reporting

6.2.1. GHG Regulations

GHGs are regulated by both federal and provincial governments as outlined in Section 5.2.5. Many individual oil sands facilities emit GHGs above the minimum values set by the regulations, and are therefore required to report GHG emissions annually to both the Government of Canada and the provincial government.

6.2.2 Relevant GHGs Emitted by Oilsands Extraction

Several gases are tracked by government GHG reporting programs including CO_2, N_2O (nitrous oxide), and CH_4 (methane), which can all be emitted during the extraction and upgrading of bitumen from oil sands (Gov AB 2010b, Env Can 2010a). Of all of these gases, CO_2 is quantitatively the largest emission. All GHGs are accounted for by calculation of the carbon dioxide equivalent (CO_2e) which is explained in Section 5.2.5 (note 10).

Other than a brief discussion in Section 6.4.6 concerning life cycle emissions, all other discussion in this Section deals with direct emissions from oil sands operations. Likewise, any comparisons with other emission sources are based on comparing direct emissions, not any other measure of total or partial life cycle emissions. Environment Canada data on GHG emissions is only reported for all emission sources as direct emissions and there is no common, credible source available to allow us to compare life cycle emissions across the major GHG emission sources.

6.2.3 Sources of Emissions from Oil Sands

In any industry, there are several potential sources for greenhouse gas emissions. These sources include stationary fuel combustion, flaring, industrial processes, venting, and on-site transportation among others (Gov AB 2010c). All of these emissions must be included in the regulatory reporting of GHGs. Steam generation is required for in situ bitumen extraction processes, both CCS and SAGD. Steam generation is usually accomplished by combustion of natural gas.

The mining, separation and upgrading of bitumen are energy intensive processes (Section 4). Overall, the main source of emissions are from natural gas usage, which are in the order of 1.9–2.5 GJ/m^3 (0.3–0.4 GJ/bbl) bitumen for mining operations, 6.3–10 GJ/m^3 (1–1.6 GJ/bbl) bitumen for in situ operations, and 0.25–2.0 GJ/m^3 (0.04–0.32 GJ/bbl) bitumen for upgrading processes (Douluwerra et al. 2009).

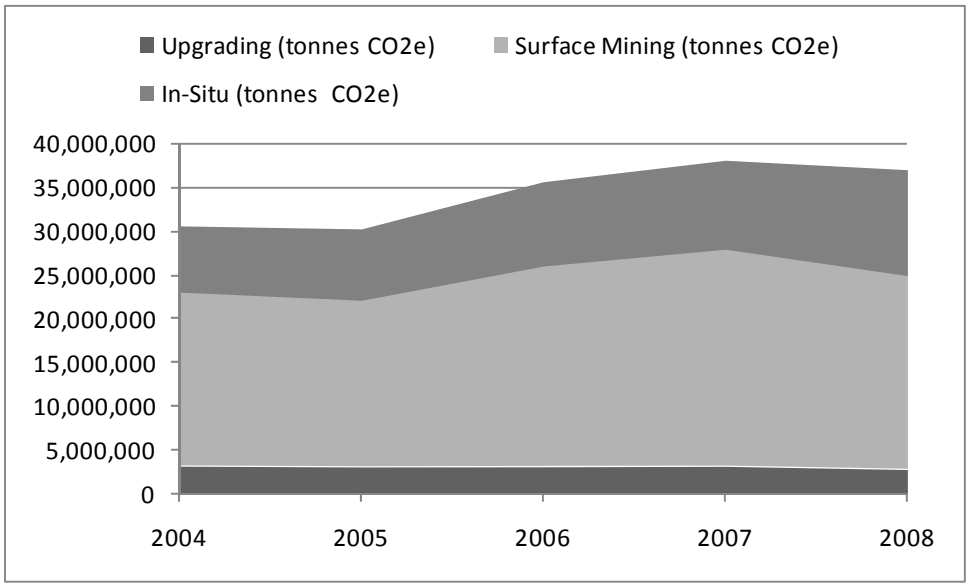
6.2.4 Calculation of GHG Emissions

The Canadian and Albertan governments do not dictate one specific method for calculating greenhouse gas emissions, but have several recommendations, to allow industry to select which method will provide the best accuracy (Gov AB 2010b, Gov Canada 2010b). but the federal government requires the calculation method to conform with the guidelines given by the United Nations Framework Convention on Climate Change (UNFCCC) which include the Intergovernmental Panel on Climate Change (IPCC) guidelines. One recommendation by the IPCC is to prioritize the sections of the plant which emit the most GHGs and focus the majority of the estimation effort on those processes. This approach will provide the highest level of accuracy for large emitters and will improve accuracy of the overall estimate (Gov Canada 2010b). The issue of quality of reporting and resulting uncertainty in GHG emission estimates is certainly an open question that is not unique to the oil sands industry.

6.3 Oil Sands GHG Emission Trends

In 2004, Environment Canada began a program requiring industry to report GHG emissions. The yearly data are collected and analyzed by Environment Canada and are arranged into yearly reports. The raw data are available online for public information (Env Can 2010a). The most current information available is for 2008. Figure 6.1 shows the yearly historical trend of the GHG emissions between 2004 and 2008, indicating that CO_2e emissions were rising steeply from 2004 to 2007, followed by a small decrease in 2008. When examining the data, it is important to consider which facilities were in operation or were reporting at that time. The facilities marked with an “x” in Table 6.1 were included for that particular year in the analysis. Between 2004 and 2008, several new facilities began operation (or began emissions reporting).

Figure 6.1 Historical total yearly oil sands GHG emissions (includes in situ, surface mining, and upgrading operations)



Source: data obtained from Environment Canada (2010a)

Oil sands industry GHGs include carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4), with CO_2 contributing the majority of emissions. The quantity of emissions from the oilsands industry is substantial, with approximately 37 million tonnes of CO_2e gas emitted in 2008. Both federal and Alberta governments have passed legislation aimed to reduce the quantities of CO_2e emitted by industry. These regulations are expected to impact CO_2e emissions in the future. Several activities such as new oilsands facilities (or increased production in existing facilities), plant operation optimization, CCS, and injection of CO_2 to improve tailings settling are expected to impact CO_2e emissions from the oil sands over the next 10 years.

The current proportion of Canada's total GHG emissions attributable to oil sands direct GHG emissions is about 5.2% based on 2008 data (Env Can 2009), and oil sands direct GHG emissions are currently 0.08% of estimated global GHG emissions (IPCC 2007), but oils sands emissions are likely to be a major source of growth in Canada's GHG emissions into the future. Oil sands direct GHG emissions in 2008 were about 19% of the total Canadian transportation GHG emissions in 2008. About two-thirds of oil demand in North America arises from the transportation sector so this is a key factor driving demand for oil sands production.

Table 6.1 Facilities considered for oil sands GHG analysis from 2004–2008

Facility	Operator	Location	2004	2005	2006	2007	2008
Surface Mining Operations (including extraction and upgraders where applicable)							
Suncor Energy Inc. Oil Sands	Suncor Energy Inc. Oil Sands	22 km NE of Fort McMurray	x	x	x	x	x
Mildred Lake and Aurora North Plant Sites	Syncrude Canada Ltd.	Fort McMurray	x	x	x	x	x
Shell Albian Sands Muskeg River Mine	Shell Canada Limited	Fort McMurray	x	x	x	x	x
Horizon Oil Sands Processing Plant and Mine	Canadian Natural Resources Limited	Fort McMurray	-	-	-	-	x
In Situ and Cogeneration Operations							
Christina Lake SAGD Bitumen Battery	EnCana Corporation	Lac La Biche	x	x	x	x	x
Cold Lake	Imperial Oil Limited	Bonnyville	x	x	x	x	x
Foster Creek Cogeneration Facility	EnCana Corporation	Bonnyville	x	x	x	x	x
Foster Creek SAGD Bitumen Battery	EnCana Corporation	Bonnyville	x	x	x	x	x
Hangingstone SAGD Demonstration Facility	Japan Canada Oil Sands Limited	RM of Wood Buffalo	x	x	x	x	x
MacKay River, In-Situ Oil Sands Plant	Suncor Energy Inc.	Fort McMurray	x	x	x	x	x
Tucker Thermal	Husky Energy Inc.	Cold Lake	-	-	-	x	x
North Tangleflags Facility	Canadian Natural Resources Limited	Bonnyville	-	x	x	x	x
Great Divide	Connacher Oil and Gas Limited	Fort McMurray	-	-	-	-	x
Jackfish SAGD Plant	Devon Canada Corporation	Conkin	-	-	-	-	x
Orion Complex	Shell Canada Limited	MD of Bonnyville	-	-	-	-	x
Wolf Lake/Primrose Thermal Operation	Canadian Natural Resources Limited	Bonnyville	x	x	x	x	x
Peace River Complex	Shell Canada Limited	Peace River	x	x	x	x	x
Pikes Peak	Husky Oil Operations Ltd.	Lloydminster	x	x	x	x	x
Bolney Thermal	Husky Energy Inc.	Lloydminster	-	x	x	x	x
Long Lake Project	Nexen Inc.	Fort McMurray	-	-	-	x	x
Surmont Central Processing Facility	Conoco Phillips Canada Resources Corp.	Anzac	-	-	-	-	x
Stand-aloneUpgraders and Co-generators							
Husky Lloydminster Upgrader	Husky Oil Operations Ltd.	Lloydminster	x	x	x	x	x
Scotford Upgrader and Upgrader Cogeneration	Shell Canada Energy Limited	Fort Saskatchewan	x	x	x	x	x

6.4 Factors Anticipated to Affect Future Emission Trends

There are some important technological initiatives that are reducing oil sands GHG emissions intensity (GHG emitted per unit of production) and there is some promise for further reductions in GHG emissions intensity (Section 4). The oil sands industry has been reducing its GHG emissions intensity which as of 2008 has been reduced 39% since 1990 (Env Can 2010c).

Several factors can potentially affect future GHG emission trends in the oil sands industry. For example, many in situ plants may require more steam to access more difficult geological formations, resulting in more natural gas being burned (Elliot 2008), which would increase GHG emissions. In situ plants have higher GHG intensities than surface mining and in situ production is predicted to grow faster than from surface mining as overall bitumen production grows. The potential influencing factors described in this section are new facilities or expansions, optimization of plant operations, government regulations, CCS, and CO_2 addition to oil sands tailings. Other factors may also influence the future GHG trends. The main factors expected to have an impact in the next decade are described below.

6.4.1 Proposed New Facilities or Expansions

The ERCB has estimated that production of bitumen in Alberta will increase significantly for both surface mining and in situ extraction techniques over the next 10 years, and that production of SCO will double by 2019 (see Section 2.2). Even though work is ongoing to reduce the amount of CO_2 emitted per m^3 of SCO, the increase in production of crude bitumen is very likely to cause CO_2 emissions to rise.

6.4.2. Optimization of Plant Operations

Optimizing plant operations for lower GHG production is one of the most convenient and low-cost methods of reducing GHG emissions from any facility. Underbakke (2008) shows the method used by the conventional upstream oil and gas industry. These strategies include improving design practices (on new units), modifying existing equipment to be more energy efficient, reducing flaring via process upgrades, and creating energy management procedures to reduce energy requirements, which would also reduce GHG emissions. With more stringent GHG restrictions, oil sands facilities will have to pursue more optimization projects to reduce GHG emissions.

6.4.3 Impact of Regulations

Future regulations will have a major impact on GHG production. Elliott (2008) forecasted oil sands GHG emissions with and without legislation in place. Without regulation, CO_2e emissions in 2020 were predicted to reach 127 million tonnes at a bitumen production level of 540,000 m^3/d (3.4 million bbl/d) including CO_2e emissions from thermal co-generation plants dedicated to electricity and thermal energy for oil sands plants. The federal government projection was lower, at 110 million tonnes CO_2e at a production level of 572,000 m^3/d (3.6 million bbl/d) (Gov Can 2008) without including the co-generation contribution.

Elliott (2008) considered that all operations would follow the provincial regulation to reduce GHG emission intensities by 12% in 2007, and the proposed federal framework requiring an 18% decrease

by 2010 and 2% each year after that. With these and a variety of other assumptions and if projected increases in production occur, Elliott (2008) projected total GHG emissions from oil sands plants could be reduced from 127 million tonnes per year to between 55 million and 91 million tonnes per year by 2020 because of GHG regulation. Although substantially improved from the business-as-usual case, the lower end of this range is still a 45% increase by 2020 from 2008 GHG emission levels making Canada's overall GHG emission reduction targets much more challenging to meet.

6.4.4 Carbon Capture and Storage (CCS)

Separating CO_2 from a source with high concentrations before emission into the environment is another method of reducing CO_2 released into the atmosphere. CO_2 sequestration and storage projects have proposed to prepare a concentrated CO_2 stream and sequester it by either adding it to a natural sink or directly discharging CO_2 into an appropriate storage location.

CCS by direct injection involves three main steps: capture of CO_2 from the source, transportation of the CO_2 to a disposal site, and injection of CO_2 at the disposal site. CO_2 capture is the most expensive component of this process, with an estimated 10–30% energy penalty (Yamasaki 2003). Several capturing technologies are available, such as absorption/stripping, adsorption/desorption, and membrane separation. One commercialized absorption/stripping process involves using amine to capture CO_2, and is already applied in the natural gas industry (Yamasaki 2003; ICO_2N 2007). The use of amine solutions has the lowest cost and highest energy saving abilities while achieving high recovery (for example, monoethanolamine CO_2 recovery is 98% [Yamasaki 2003]). After capturing CO_2, the gas should be transported and injected into an appropriate location for sequestration.

Underground sequestration is a promising candidate for CCS because Alberta has several geological options for suitable injection sites (Bachu and Grobe 2000). This process involves injection of CO_2 deep underground into secure geological formations for long-term storage. The WCSB has been estimated to be able to hold enough CO_2 emissions to last hundreds of years (ICO_2N 2007). Current use of these methods for enhanced oil recovery (EOR) makes underground sequestration a feasible option for CO_2 storage (Yamasaki 2003; ICO_2N 2007). In the EOR process, captured CO_2 is injected into conventional oil reserves which have been mostly depleted. This injected gas increases pressure in the reservoir, enhancing oil flow, making oil easier to recover (Gov AB 2009b). Several locations exist for potential underground CO_2 sequestration sites including coal seams, depleted oil or gas wells, salt caverns, and saline aquifers (Yamasaki 2003; Gov AB 2009b). Unfortunately for the specific case of GHG emissions from oil sands, the geology of northeastern Alberta, where most of the oil sands activity is concentrated, is generally not suitable for CCS because it is located at the shallow end of the Alberta sedimentary basin and only a qualified range of possible geological storage options may be feasible (Bachu and Grobe 2000). GHG emissions for bitumen upgraders located elsewhere in Alberta offer more promise for CCS.

The government of Alberta has embraced CCS as the most effective way to reduce CO_2 emissions and achieve its overall GHG reduction commitments. The government has recently committed to invest approximately $2 billion into developing several CCS projects in Alberta (Gov AB 2009b, 2010c). The following projects have been listed as part of this commitment (Gov AB 2010d):

1. Project Pioneer is located west of Edmonton at the Keephills 3 plant. CO_2 captured will be stored approximately 3 km below ground or used to enhance oil recovery in conventional oil fields in the region. This project is anticipated to start CCS in 2015, capturing about 1 million tonnes of CO_2 per year.

2. Shell Quest is part of the Shell operations located near Fort Saskatchewan. CO_2 will be captured from hydrogen units at Shell's bitumen upgrader and shipped via pipeline to a deep saline aquifer, 2 km underground (Quest 2010). The project is expected to remove 1.2 million tonnes of CO_2 per year and store it underground beginning in 2015.

3. Alberta Carbon Trunk Line involves building a pipeline approximately 240 km long to transport CO_2 for EOR in depleting oilfields. CO_2 emissions will initially be captured and transported from the Agrium Redwater Complex. Once the North West Upgrader (for bitumen) is built, its CO_2 emissions will also be captured and transported through the Alberta Carbon Trunk Line.

4. Swan Hills Synfuels is an in situ coal gasification project which will use captured CO_2 to access deep coal seams (normally believed to be too deep to mine). Approximately 1.3 million tonnes of CO_2 will be removed each year, beginning in 2015 (Swan Hills Synfuels 2010).

These province- and industry-sponsored projects should capture a significant amount of CO_2 each year. Very likely other projects will reduce GHG emissions from oil sands extraction and upgrading operations. Oil sands interest in this technology led to creation of ICO_2N, a joint venture to explore CCS, which includes Suncor, Shell, Husky Energy, Syncrude, Esso (Imperial Oil), Nexen, and CNRL, among others. These companies have joined together to report opportunities and costs of CCS (ICO_2N 2007). However, Shell is the only oil sands operator participating in the government sponsored CCS demonstration projects noted above, in this case for its stand-alone bitumen upgrader in their industrial complex near Fort Saskatchewan, Alberta.

There is considerable appeal for pursuing CCS in Alberta, but, given the location of geological sinks available for storing GHGs, the direct impact of CCS on reducing oil sands GHG emissions is not likely to be substantial. Implementation of CCS in Alberta will likely reduce GHG emissions from other major emitters.

McColl (2009) estimates the cost for post-combustion capture—the technology applicable to current oil sands projects—would be $55 per tonne CO_2e within a range from $50 to $70 per tonne of CO_2e. The current Alberta regulation assigning a $15 per tonne CO_2e penalty to industrial emitters who fail to meet their regulated GHG emissions intensity targets shows it will make more economic sense for these non-compliant emitters to pay the fixed $15 per tonne CO_2e penalty into Alberta's Climate Change and Emissions Management Fund. Likewise, it is clear that the amount collected into this fund will not be adequate to cover the cost of implementing technology like CCS.

6.4.5 Tailings Settling Improvement by CO_2 Addition

Another potential location to sequester CO_2 while improving settling rates is to inject the CO_2 into oil sand tailings. Many researchers are studying MFT to increase the settling rate and remove some of this

“sludge” type material from tailings ponds. One process of interest is being developed by Apex Engineering, Inc., and involves treating oil sands with $Ca(OH)_2$ and CO_2 (Chalaturnyk et al. 2002) and then going through a thickening process. The $Ca(OH)_2$ reacts with the injected CO_2 to produce $CaCO_3$ in crystal form. These $CaCO_3$ crystals supply a large solid–liquid interfacial area, and could possibly adsorb ultra-fine particles, causing them to settle faster. Testing of this process has given promising results, particularly at higher temperatures.

A similar process of using oil sands tailings streams to sequester CO_2 was used on a pilot scale by a joint venture involving Canmet ENERGY Devon, Syncrude and CNRL (Mikula 2010). Results showed great improvement of settling time, improved tailings handling ability, and allowed CNRL to pursue commercializing this technology. The amount of CO_2 to be sequestered is estimated between 300,000 to 3,000,000 tonnes per year, depending on the process application. The timeframe of this technology becoming available is anticipated to be within the next 3–4 years. CNRL has built in 2009–2010 a 1/100 scale pilot plant to demonstrate the use of CO2 and polymer addition as the means for meeting ERCB Directive 74 on tailings management.

6.4.6 Life-Cycle Emissions from Various Petroleum Sources

The majority of GHG emissions, an average of 74% and 80% of total life cycle GHG emissions for reformulated gasoline and low sulphur diesel, respectively, result from combustion of fuel in vehicles (McKellar et al. 2009). Given the dominance of end use as the source of GHG emissions, an overall comparison among petroleum sources should also consider a “well-to-wheels” life-cycle comparison that includes end use.

Charpentier et al. (2009) reviewed studies of emissions from oil sands vs. conventional oil. They found reported emissions for production of synthetic crude oil (SCO) ranged from 9.2–26.5 and 16.2–28.7 g CO_2e / MJ SCO, respectively, through surface mining and upgrading or in situ and upgrading processes compared to 4.5–9.6 g CO_2e / MJ of crude for conventional oil production. However, on a “well-to-wheels” basis, GHG emissions associated with producing reformulated gasoline from oil sands with current surface mining with upgrading, in situ with, and in situ without upgrading technologies are 260–320, 320–350, and 270–340 g CO_2e / km, respectively, compared to 250–280 g CO_2e / km for production from conventional oil.

Jacobs Consultancy (2009) performed a well-to-wheels life cycle assessment for the Alberta Energy Institute comparing oil sands bitumen sources with other sources of petroleum. In one relevant example, they found that for production and vehicle use of reformulated gasoline, conventional crude ranged from a low (Arab Medium) 98.3 g CO_2e M/J to a high (Nigerian Bonny Light) 106.4 g CO_2e / MJ compared with 114.2 g CO_2e / MJ for California thermal enhanced recovery heavy crude, 116.1 g CO_2e / MJ for in situ SAGD, coker-upgraded synthetic crude, and 108.2 g CO_2e / MJ for mined, coker-upgraded synthetic crude.

In summary, comparisons of GHG emissions from oil sands with other petroleum sources is very dependent on the petroleum source that is used for comparison and the specific details concerning the processing of bitumen. Nonetheless, life-cycle GHG emissions from oil sands are in the upper part or

at the top of range of all petroleum sources. In situ bitumen recovery is the highest for GHG emissions and its proportion of bitumen production is increasing.

6.5 Summary of GHG Emissions as an Environmental Issue for the Oil Sands

Oil sands industry GHGs include carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4), with CO_2 contributing the majority of emissions. Emissions of GHG from the oilsands industry is substantial - approximately 37 million tonnes of CO_2e gas emitted in 2008. Both federal and provincial governments have legislation aimed at reducing GHG emitted by industry. These regulations are expected to impact oil sands industry direct GHG emissions in the future.

The current proportion of Canada's total GHG emissions attributable to oil sands direct GHG emissions is about 5.2% based on 2008 data (Env Can 2009), and oil sands direct GHG emissions are currently 0.08% of estimated global GHG emissions (IPCC 2007), but oils sands emissions are likely to be a major source of growth in Canada's GHG emissions into the future.

Canada's GHG emissions have been rising since Canada committed to the Kyoto accord (an overall increase of 142 million tonnes from 1990 to 2008), 80% of that increase in Canada's GHG emissions was independent of the growth in GHG emissions from the oil sands industry. The total 2008 GHG emissions related to the oil sands were 37.2 million tonnes in 2008 and the increase in GHG emissions from the oil sands from 1990 to 2008 was roughly 20.4 million tonnes because of the growth in bitumen production (Env Can 2010c).

Oil sands GHG emissions in 2008 were about 19% of total Canadian transportation GHG emissions in 2008. About two-thirds of demand for oil in North America arises from the transportation sector.

Some important technological initiatives are reducing oil sands GHG emissions intensity (GHG emitted per unit of bitumen production) and there is some promise for further reductions in GHG emissions intensity. Several activities such as new oil sands facilities (or increased production in existing facilities), plant operation optimization, CCS and injection of CO_2 to improve tailings settling are expected to impact GHG emissions from the oilsands within the next 10 years. The oil sands industry has been reducing its GHG emissions intensity which as of 2008 has been reduced 39% since 1990 (Env Can 2010c). GHG emissions intensity is currently higher for in situ projects than surface mining projects and in situ production is expected to grow more than surface mining production

Alberta adopted the first regulatory system in North America for GHG, including financial penalties of \$15/tonne of CO_2e for missing GHG emission targets. This compares with estimates of \$50 to \$70 per tonne of CO_2e (McColl 2009) for post-combustion carbon capture—the technology applicable to current oil sands projects. CCS is being pursued by the Government of Alberta for major reduction in Alberta GHG emissions, but the geology of north-eastern Alberta is generally not a good candidate for CCS meaning that CCS is likely a better technology for reducing GHG emissions from coal-fired thermal power generation (the largest source of GHG emissions in Alberta) than directly from the oil sands. This creates some inevitable challenges in balancing the costs of GHG emission reduction among sources.

Overall, the development of national regulatory policy for controlling GHG emissions is inherently dependent upon the quality of the data obtained and reported by Environment Canada. There is enormous potential for uncertainty in the validity of these estimates given the wide range of information that must be tracked and, in many cases, assumed to produce these data. While there are quality control and assurance measures required for Canada's international reporting to IPCC, it is not clear that these measures are adequate to deal with all the challenges which are apparent (Env Can 2010c).

7. AIR QUALITY

Air quality issues must always be a primary concern for any major human developments because they usually emit air pollutants and may contribute to a degradation of ambient air quality. Consideration of air quality will be done by characterizing major air pollutants that are emitted by oil sands developments, comparative levels of air pollutant emissions, and ambient air quality.

7.1 Major Air Pollutants

Over the past 50 years, there has been much research and monitoring to characterize major air pollutants. Their characteristics are now widely known and described (AENV 2009; Env Can 2010; Adamowicz et al. 2001; US EPA 2010; WHO 2006). Those primarily relevant to oil sands developments are reviewed below.

7.1.1 Oxides of Sulphur (SO_x)

The oxides of sulphur (SO_x) are a group of inorganic air pollutants containing sulphur combined with varying amounts of oxygen. The most common SO_x pollutant is sulphur dioxide (SO_2), a pungent, strong-smelling, colourless gas that most commonly arises from combustion of materials containing sulphur, typically fossil fuels. SO_2 is usually the SO_x pollutant which is monitored and controlled. Other SO_x pollutants include SO_3, sulphates and H_2SO_4, which have the capability to acidify water and soil and may also contribute to fine particle formation. More than 90% of emissions arise from industry, power generation, and domestic heating (using coal or fuel oil) with negligible natural emission sources (except for volcanic eruptions). The SO_x pollutants are respiratory irritants that can cause a variety of adverse human health effects.

Annual mean concentrations of SO_2 in urban areas using primarily natural gas for home heating are generally 20–60 $\mu g/m^3$, with 24 hour means normally less than 125 $\mu g/m^3$ (WHO 2000). From 2001 to 2008, the oil sands capital of Fort McMurray (Athabasca Valley) had an annual average SO_2 ranging from 2.1 to 3.2 $\mu g/m^3$ (CASA 2010). Over the same period, major Alberta cities remote from any oil sands influence Calgary (east) had an annual average SO_2 from 2.9 to 8.0 $\mu g/m^3$ and Edmonton (east) had an annual average SO_2 from 3.4 to 6.1 $\mu g/m^3$. Alberta's ambient air quality objectives and the national air quality objectives for SO_2 are 30 $\mu g/m^3$ for an annual average, 150 $\mu g/m^3$ for a 24 hour average and 450 $\mu g/m^3$ for a one-hour average. The differing concentrations for different averaging times reflect the reality that concentrations fluctuate over time and impacts for short term exposures require higher exposure concentrations to occur than for long term exposures and impacts.

7.1.2 Oxides of Nitrogen (NO_x)

The oxides of nitrogen (NO_x) are a group of inorganic air pollutants containing nitrogen combined with varying amounts of oxygen. Nitrogen dioxide (NO_2) is the most common NO_x pollutant which arises from high temperature combustion of fuels; unlike SO_x, however, the nitrogen does not primarily come from fuel or emission sources, but instead from the air which is composed of about 78% nitrogen. NO_x is found in power plant emissions, vehicle exhaust, and smoke, including tobacco smoke. NO_2 is typically the NO_x pollutant which is monitored and controlled. Other NO_x pollutants include nitric

oxide (NO), nitrous acid (HNO_2), nitric acid (HNO_3), and nitrates which contribute to fine particle formation. Most of the NO emitted into ambient air is quickly oxidized to NO_2. Nitric acid has the capability of acidifying water and soil. With sunlight and volatile organic compounds, NO_2 can contribute to the formation of ground-level ozone and other photochemical reaction products. Industrial, power generation, and domestic heating sources contribute about 40% and mobile (vehicle) emissions contribute about 50% of total emissions in Canada. Natural emission sources are generally less than 10%. Most NO_x pollutants are respiratory irritants which can cause a variety of adverse human health effects.

For NO_2, natural background (WHO 2000) annual mean concentrations are 0.4–9.4 μg/m^3, urban concentrations are 20–90 μg/m^3, and hourly peaks are 75–1,015 μg/m^3. From 2001 to 2008, Fort McMurray (Athabasca Valley) annual average NO_2 ranged from 17.1 to 19.5 μg/m^3 (CASA 2010). Over the same period, Calgary (central and central2) annual average NO_2 ranged from 35.5 to 50.4 μg/m^3 and Edmonton (central) annual average NO_2 ranged from 37.4 to 47.2 μg/m^3. Alberta ambient air quality and national air quality objectives for NO_2 are 60 μg/m^3 for an annual average, 200 μg/m^3 for a 24 hour average, and 400 μg/m^3 for a one-hour average. Indoor air concentrations may average more than 200 μg/m^3 if gas combustion appliances are used without venting.

7.1.3 Particulate Matter (PM)

Particulate Matter (PM_x, where x refers to median particle size in micrometers, μm, 10^{-6}m) refers to a complex range of fine particles including soot, dust, dirt, and secondary acidic and organic aerosols which can remain suspended in air. The composition of PM is complex and diverse, including acids (e.g., nitrates and sulfates), organic chemical mixtures (e.g., soot), inorganic chemicals including metals (e.g., lead fume), and soil particles. PM arises from combustion (smoke, including tobacco smoke, is caused by light-scattering PM), grinding, mixing, surface disturbance, and various atmospheric chemical processes, as well as natural sources of dust. The health effects of PM depend upon the effective (aerodynamic) size of the particles which determine where in the respiratory system the PM can reach and/or be deposited, and the chemical composition of the PM. The size range of PM is designated by the subscript which represents the effective median diameter in μm.

PM is now commonly monitored in two categories:

- PM_{10}, inhalable coarse particles, such as those found near roadways and dust-emitting industries, are larger than 2.5 μm and smaller than 10 μm in effective diameter.
- $PM_{2.5}$, fine particles, found in smoke and smog, are 2.5 μm in diameter or smaller. $PM_{2.5}$ can be directly emitted from combustion sources such as forest fires, or they can form when gases emitted from power plants, industries, and vehicles react in the atmosphere.

Coarse PM (PM_{10} and larger) is primarily material derived from the earth's crust, such as soil and minerals. Fine PM ($PM_{2.5}$), usually results from anthropogenic activities and contains sulfate, nitrate, ammonium, metals, elemental carbon, and large numbers of individual organic compounds. Ambient $PM_{2.5}$ is often dominated by particles formed during combustion from material that is in gaseous form, but then re-condenses before or shortly after emission to the atmosphere (US EPA 2004).

- Primary particles are emitted directly into the atmosphere from anthropogenic sources (e.g., combustion-generated fine particles, or coarse particles that result from crushing, grinding, and erosion).

- Secondary particles are formed through chemical reactions involving gases such as sulphur dioxide (SO_2), nitrogen oxides (NO_x), volatile organic compounds (VOCs), and ammonia (NH_3), and other particles and gases in the atmosphere.

From 2001 to 2008, Fort McMurray (Athabasca Valley) had an annual average $PM_{2.5}$ ranging from 3.52 to 6.94 μg/m^3 (CASA 2010). Over the same period, Calgary (central and central-2) had an annual average $PM_{2.5}$ from 5.58 to 15.94 μg/m^3 and Edmonton (central) had an annual average $PM_{2.5}$ from 4.76 to 8.35 μg/m^3. Alberta's ambient air quality objective and the Canada-wide Standard (CWS) to take effect in 2010 for $PM_{2.5}$ is 30 μg/m^3 (24 hour average). From 2001 to 2008, Edmonton, Calgary, and Fort McMurray experienced an average of two or fewer days per year above the CWS. Over this eight-year period Edmonton had a total of 9 days, Calgary had 16 days and Fort McMurray had 12 days exceeding the 24 hour average CWS.

7.1.4 Carbon Monoxide (CO)

Carbon monoxide (CO) is a by-product of incomplete combustion of carbon-containing fuels, distinct from CO_2 which is a product of complete combustion. CO is both colourless and odourless. Transportation (motor vehicles and other fossil fuel engines) are the major source of CO emissions, so atmospheric concentrations of CO are generally correlated with traffic or concentrations of engine emission sources. Wood burning (residential heating and fireplace emission) and forest fires are localized sources of CO. Because CO sources are typically ground-level emitters, ambient CO concentrations are typically influenced by low ventilation conditions such as occur under atmospheric thermal inversions. CO is toxic to humans at high concentrations because of its ability to bind with hemoglobin and reduce the ability of blood to transport oxygen from the lungs to body organs and the brain.

Background concentrations of CO worldwide range between 0.06 mg/m^3 and 0.14 mg/m^3 (WHO 2000). In traffic areas of large European cities, the eight-hour average CO concentrations are generally lower than 20 mg/m^3 with short-lasting peaks below 60 mg/m^3. From 2001 to 2008, Fort McMurray (Athabasca Valley) had an annual average CO ranging from 0.25 to 0.30 mg/m^3 (CASA 2010). Over the same period, Calgary (central and central-2) had an annual average CO ranging from 0.408 to 0.756 mg/m^3 and Edmonton (central) had an annual average CO ranging from 0.396 to 0.708 mg/m^3.

7.1.5 Ozone (O_3)

Ozone (O_3) is a reactive gas, the predominant photochemical oxidant that is produced in the atmosphere resulting from reactions involving sunlight and other air pollutants (NO_x and volatile organic compounds, VOCs) which are considered to be O_3 precursors. O_3 produced in this manner is typically referred to as ground-level O_3, the primary component of smog, as distinct from that in the stratospheric O_3 layer located 10–40 km above the earth's surface where the O_3 provides a partial barrier to incoming UV radiation from the sun. O_3 is not emitted directly as an air pollutant to any

degree. While O_3 is primarily associated with urban air pollution in sunny regions with transportation-related NO_x emissions, O_3 can also be produced by photosynthetic reactions of naturally occurring VOCs emitted from forested regions. O_3 is an irritant and corrosive gas that has been linked to a number of adverse respiratory responses in humans.

Background hourly levels of O_3 have been reported (WHO 2000) in the range of 40 to 70 μg/m^3 but occasionally as high as 120 to 140 μg/m^3. In Europe, maximum hourly O_3 concentrations may exceed 300 μg/m^3 in rural areas and 350 μg/m^3 in urbanized regions.

Alberta's ambient air quality objective for O_3 is 160 μg/m^3 as a one-hour average. The CWS to take effect in 2010 for O_3 is 127 μg/m^3 as an eight-hour average. During the period from 2001 to 2008, there were no values exceeding the CWS in Fort McMurray (Athabasca Valley), Calgary (central) or Edmonton (central) (CASA 2010).

7.1.6 Volatile Organic Compounds (VOCs)

VOCs represent a wide range of organic (carbon-containing) chemicals which have high enough vapour pressure to evaporate into the atmosphere as a gas at ambient temperatures. VOC include a wide range of individual organic chemicals and chemical mixtures with only their volatility in common. VOCs can be emitted as products of incomplete combustion of carbon containing fuels and as volatile fugitive emissions from handling of volatile organic chemicals such as gasoline, diesel, organic solvents, and petroleum sources. VOCs can play a major role in the formation of photochemical smog and ground level O_3. Some VOCs are irritants (e.g., aldehydes), some are a source of odour nuisance (various gasoline and diesel volatiles), and some are carcinogens (e.g., benzene and vinyl chloride). Because of the diversity of VOCs sources and individual characteristics, VOCs are not regulated as a group, but Alberta has published ambient air quality guidelines for 23 individual organic compounds which would be considered VOCs.

An individual VOC of health concern is benzene which occurs in ambient air from cigarette smoke, combustion of carbon-based fuels, evaporation of gasoline (containing up to 5% benzene), and petroleum and natural gas processing (WHO 2000). Typical mean ambient air concentrations of benzene in rural and urban areas are about 1 and 5–20 μg/m^3, respectively.

The median and maximum benzene levels measured outdoors in the Fort McMurray air contaminant exposure study were 1.3 and 2.4 μg/m^3, respectively (WBEA 2007).

7.1.7 Polycyclic Aromatic Hydrocarbons (PAHs)

PAHs refer to a wide range of chemical compounds with the common feature of having two or more aromatic (i.e. benzene) rings fused together. PAH are semi-volatile with those having a smaller number of rings (e.g. naphthalene with 2 rings) being VOC. PAH having larger numbers of rings are progressively less volatile and less water soluble. PAH are typically produced by incomplete combustion or pyrolysis[1] decomposition of carbon-containing fuels and are major components of soot and smoke particles. PAH became prominent early in the history of occupational medicine with an

[1] Thermal decomposition in the absence of oxygen.

association established between chimney sweeps and cancer of the scrotum that was attributed to chronic soot exposure. Laboratory research established the carcinogenic properties of some of the larger 4- and 5-ring PAHs such as benzo-[a]-pyrene (BaP); many more have shown no carcinogenic properties and most, including heterocyclic PAHs (those containing sulphur or nitrogen), nitro-PAHs, and oxygenated PAHs, have not been fully tested. Polycyclic Aromatic Compounds (PAC) is a more general term that implies inclusion of all these compounds. In addition to inhalation exposure to PAHs, ingestion of food on which PAHs have been deposited is an exposure route that must be considered in human health risk assessments. The bitumens of the oil sands are heavily to severely biodegraded crude oils dominated by alkylaromatic hydrocarbons and alkylaromatic hetero-compounds, some of which are likely oxidized and possibly with carboxyl groups attached, which will increase their water solubility. These features make bitumen a very complex mixture which cannot be realistically assessed, compound by compound.

Annual mean concentrations of carcinogenic benzo-[a]-pyrene (BaP) in major European urban areas are in the range 1 to10 ng/m^3. In rural areas, the concentrations are < 1 ng/m^3 (WHO 2000). The BaP annual mean concentration for the five-year period of 1998 to 2003 for Edmonton was 0.091 ng/m^3, a level which was lower than most Canadian cities (CASA 2010). Montreal, with an annual mean of 0.77 ng/m^3, had a significantly higher concentration of BaP than any other Canadian city studied.

7.1.8 Metals

Except for mercury which is emitted as a vapour, most metals are emitted as fine particles and would be included as a component of PM_{10} or $PM_{2.5}$. Other metals that may be important air emissions from the oil sands industry are cadmium, nickel, and vanadium. Generally, air emissions of metals are not a direct inhalation threat, because of the very small dose delivered in this manner, but metals may be a concern because of their dispersal to the environment where they may concentrate in sediments, soils, vegetation, and wildlife.

Atmospheric concentrations of mercury have been reported as about 2–4 ng/m^3 in background areas remote from industry and 10 ng/m^3 in urban areas (WHO 2000). Cadmium is a major contaminant in tobacco smoke which makes background air levels difficult to judge. Urban ambient air concentrarions of nickel have been reported in the range 1–10 ng/m^3 in urban areas, with much higher concentrations (110–180 ng/m^3) in heavily industrialized areas and larger cities (WHO 2000). The natural background concentration of vanadium in the air in Canada was reported as 0.02 to 1.9 ng/m^3 and in urban areas from 50 ng/m^3 to 200 ng/m^3 (NAS 1974). Atmospheric concentrations for trace metals are not routinely monitored in Canada or in the oil sands region.

7.1.9 Total Reduced Sulphur (TRS)

Reducing[2] environments such as anaerobic digestion found in swamps or decomposing organic wastes produce odorous emissions that include a collective mixture called total reduced sulphur (TRS),

[2] Reduction means the opposite of oxidation. Simple examples would be the oxidation of carbon to yield carbon dioxide or the reduction of carbon to yield methane. Combustion is an oxidation process, which is why it requires oxygen. Reduction, in contrast is a process where potential energy is stored in a chemical, as opposed to being released, as it is in the case of combustion.

including hydrogen sulphide (H_2S), methyl mercaptan (CH_3SH), dimethyl sulphide (C_2H_6S), dimethyl disulphide ($C_2H_6S_2$), carbon disulphide (CS_2), carbonyl sulphide (COS), and other organic compounds containing sulphur in a reduced state. The reduced sulphur species most often emitted from industrial processes are commonly H_2S, CH_3SH, C_2H_6S, and $C_2H_6S_2$ (Kindzierski et al. 2009; OME 2007; AENV 2004). These were most commonly recognized in air emissions from pulp and paper plants, petroleum refineries, and upstream oil and gas production. Natural gas, as found in geological formations, often contains hydrogen sulphide, which is described as sour gas. Most TRS compounds have extremely low odour thresholds (i.e., compounds are detectable at very low concentrations) and generally do not pose a human health risk beyond the odour nuisance, but H_2S at much higher concentrations (more than 10,000 times its odour threshold) is acutely toxic to humans and often contributes to occupational fatalities for confined space workers.

7.1.10 Odours

TRS are typically the most common source of odours from petroleum (including oil sands) sources, but many other organic compounds found in bitumen can contribute to odours. Odour emissions are very difficult to monitor because of the diverse sources which may cause offensive odours and because they are often transient, making it difficult to record odour events and track their emissions sources.

7.2 Emissions from Oil Sands Operations

There are multiple sources of emission from oil sands operations—mining, extraction, upgrading, in situ recovery, and waste management. Emissions from combustion and upgrading sources that are emitted through stacks are explicitly covered in EPEA approvals and are subject to source monitoring (continuous in many cases). Vehicles and other heavy equipment all contribute combustion emissions.

Volatile contaminants (VOCs, benzene, TRS) will arise from evaporation from tailings ponds, out-gassing from bitumen at the mine face, and from fugitive emissions wherever hydrocarbons are being handled. Quantifying these emissions is notoriously difficult and the data available in NPRI on this subject do not provide enough detail to know what sources have been estimated nor how valid the numbers are. A study commissioned by Environment Canada (Worley Parsons 2009) attempted to estimate fugitive emissions of volatile contaminants from the exposed bitumen face in mines and from the surface of tailings ponds.

NPRI reporting of non-point source emissions of benzene and TRS in 2007 and 2008 for Syncrude, Suncor, and Shell are summarized in Table 7.1.

Table 7.1 Non-point source (fugitive) emissions of benzene and TRS (NPRI)

Year	Oil Sands Source	Benzene (tonnes)	TRS (tonnes)
2007	Suncor	14.5	94.56
	Syncrude Canada Ltd.	40.5*	48.16
	Shell Albian Sands Muskeg River Mine	3.0	N.R.
	Total	**58.0**	**142.72**
2008	Suncor	77.0	753.54
	Syncrude Canada Ltd.	39.94	39.96
	Shell Albian Sands Muskeg River Mine	2.64	N.R.
	Total	**119.58**	**793.50**

*Worley Parsons (2009) reported that the total non-point source emissions of benzene were 39.16 tonnes from tailings ponds and 0.73 from exposed mine face. The Syncrude Canada Ltd. NPRI report attributed another 0.565 tonnes to losses from storage and handling.

Source: NPRI.

In contrast, Worley Parsons (2009) predicted, using emission factor estimates and assuming a threefold increase in exposed mine surface by 2022, that total oil sands fugitive emissions of benzene from mines would range from 5 to 7 tonnes per year and TRS from 11,900 to 12,000 tonnes per year. Assuming a 1.6-fold increase in surface area of tailings ponds by 2022, Worley Parsons (2009) predicted oil sands fugitive emissions of benzene from mines would range from 29 to 98 tonnes per year and TRS from 344 to 805 tonnes per year. Benzene estimates are in a comparable range with the NPRI reporting in Table 7.2, but the TRS numbers are vastly different. Most of the numerical difference is associated with very high TRS emissions predicted from mine faces by Worley Parsons which may not be included in the estimates for the NPRI reporting. This TRS part of the discrepancy does not take into account the TRS / H_2S emission problems with ambient air quality that is discussed in the next subsection. It is noteworthy how large a change in both benzene and TRS was reported to NPRI by Suncor between 2007 and 2008. Suncor noted in its 2008 NPRI report that different estimation methods were used compared with 2007.

A major factor in benzene emissions for tailings ponds is whether naphtha is used as the diluent in the extraction process. This will normally be the case where there is an on-site upgrader (see Section 4.2.1) as part of the operations. Naphtha contains benzene, meaning naphtha losses to the tailings pond will allow greater benzene emissions. Syncrude noted in their NPRI reporting that minimizing naphtha loss is a critical component of minimizing benzene emissions from its Mildred Lake tailings pond.

The subject of non-point (fugitive) emissions of air contaminants from mines and tailings ponds is highly uncertain and currently available estimates are unlikely to be entirely valid. There is clearly scope for extensive, targeted data gathering to validate actual emissions from these sources. Likewise, the overall emissions inventory data reported to NPRI should be validated to insure the integrity of that data base.

In addition to combustion sources (for $PM_{2.5}$), larger particulate emissions can come from dry tailings dust and dust from coke storage produced in bitumen upgrading (Section 4.6).

Table 7.2 (7.2a for 2007; 7.2b for 2008) provides a summary of estimated major emissions reported by the National Pollutant Release Inventory (Environment Canada) compared with all industries in Canada required to report to NPRI under CEPA.

This table shows annual emission estimates for major criteria air pollutants ($PM_{2.5}$, SO_2, NO_x, VOC, CO) and for important toxic pollutants (PAH, lead, cadmium, and mercury). National comparison data were not available for two other pollutants of interest, benzene and arsenic. Table 7.2a allows comparison of emissions for the oil sands industry that were operational and reporting to NPRI for the 2007 reporting year with other industrial emissions and other emission sources in Canada. Table 7.2b allows comparison of emissions for the oil sands industry that were operational and reporting to NPRI for the 2008 reporting year.

This summary clearly shows that, overall, the oil sands industry is a major emitter of both the major criteria air pollutants and the listed toxic pollutants. For the major criteria air pollutants, the oil sands industry contribution to the total Canadian industrial sources plus electric power generation utilities in 2007 and 2008 ranges from a low of 1.7% for CO to a maximum of 9.2% for VOC. The oil sands industry ranked among major industrial categories plus electric power generation utilities in 2007 and 2008 for emissions from a low of twelfth for $PM_{2.5}$ to a high of third for VOC. To become the largest industrial emitter in Canada, the 2007 and 2008 oil sands industry would have to increase by about five-fold for SO_x and VOC, and by more than seven-fold in any other category of criteria air pollutants.

For the four categories of toxic air pollutants, the oil sands industry contribution to the total Canadian industrial sources plus electric power generation utilities in 2007 and 2008 ranges from a low of 0.01% for the sum of 4-PAH to a maximum of 2.0% for mercury. The oil sands industry ranked among major industrial categories plus electric power generation utilities for emissions in 2007 from a low of eighth for a sum of 4-PAH and for lead to a high of fifth for mercury. The 2007 and 2008 oil sands industry would have to increase by more than fifteen-fold to become the largest industrial emitter in Canada for any category of these four toxic air pollutants.

Table 7.2a 2007 Total air pollutants emissions for Canada highlighting oil sands industry emissions

Sectors	**$PM_{2.5}$ (tonnes)**	**SO_x (tonnes)**	**NO_x (tonnes)**	**VOC (tonnes)**	**CO (tonnes)**	**ΣPAH 4* (kg)**	**Pb** (kg)**	**Cd*** (kg)**	**Hg (kg)**
Industrial Sources									
Abrasives Manufacture	6	-	-	28	5	-	-	-	-
Aluminum Industry [sum PAH: 20% BC; 80% PQ]	5142	65934	2026	1219	352589	39836			30.5
Asbestos Industry	9	224	86	-	28	-	-	-	-
Asphalt Paving Industry	1561	238	25	9	800	14	4598.6	60.8	52.2
Bakeries	1	-	-	7817	-	-	-	-	-
Cement and Concrete Industry	9123	39376	41710	397	18160	8	966	18.9	298.7
Chemicals Industry	1321	14438	20992	13055	15164	29	967	3.4	36.7
Mineral Products Industry	621	913	534	270	3490	-	-	-	-
Foundries	5723	53	158	392	53850	-	259	4	-
Grain Industries	2317	210	1127	2759	378	-	-	-	-
Iron and Steel Industries	2727	27900	13052	1506	46652	392	6497	268.4	746
Iron Ore Mining Industry	2218	17101	14485	31	24136	9	-	-	-
Mining and Rock Quarrying	11923	5105	14959	2806	14659	0	11512	366.2	17
Non-Ferrous Smelting and Refining Industry [Sox: 63% MB; 31% ON]	2727	623744	3819	65	18005	0	216272	24830	1417
Pulp and Paper Industry	12317	54478	37283	18208	71282	201	2209	302	57
Wood Industry	32609	2518	11790	69971	341953	2	173	7	3
Upstream Petroleum Industry (except oil sands)	7234	181676	451546	583435	476653	4	-	-	-
Oil Sands Industry	**2820**	**127273**	**38436**	**20965**	**8580**	**6**	**893**	**134**	**82**
Oil Sands in situ extraction and processing	235	8771	10122	2026	7149	-	-	47	-
Oil Sands mining extraction, processing, and upgrading	2585	118502	28314	18939	1431	6	893	87	82
Downstream Petroleum Industry	2644	85783	30062	44865	19827	60	489	137	50
Petroleum Product Transportation and Distribution	196	2017	36322	194	13317	-	-	-	-
Other Industries	3323	9538	17846	51903	9466	8	10020	534	186
Total Industrial Sources (not incl. Electric Power Gen. Utilities)	**106463**	**1258521**	**736257**	**819897**	**1488995**	**40566**	**254738**	**26665**	**2975**
Total Industrial Sources + Electric Power Generation Utilities	**113346**	**1751593**	**973938**	**821933**	**1528795**	**40573**	**257233**	**27136**	**5094**
Oil Sands as a % of Total Industrial & Electric Power Generation	**2.5%**	**7.3%**	**3.9%**	**2.6%**	**0.6%**	**0.01%**	**0.3%**	**0.5%**	**1.6%**
Oil Sands rank among industry & power generation categories	**#9**	**#4**	**#4**	**#5**	**#15**	**#9**	**#9**	**#6**	**#5**
Non-industrial sources									
Commercial fuel combustion	2401	35267	29805	677	15837	3	1184	296	39
Electric power generation (utilities)	6883	493072	237681	2036	39800	7	2495	471	2119
Coal	4393	469700	179006	582	18331	-	1561	305	2037
Total non-industrial sources	**119586**	**539976**	**314577**	**159841**	**775947**	**56648**	**5490**	**1271**	**2262**
Total mobile sources	**64885**	**101529**	**1209463**	**553828**	**6852157**	**1837**	**44557**	**118**	**2**
Total incineration	**517**	**2213**	**2455**	**1507**	**5941**	**0**	**626**	**50**	**1057**
Total miscellaneous	**8466**	**-**	**34**	**427431**	**4007**	**1**	**2005**	**75**	**280**
Total open sources	**833501**	**1184**	**6027**	**308836**	**25863**	**1089**	**417**	**24**	**491**
Total natural sources	**211210**	**178**	**202470**	**24411109**	**2484823**	**91584**	**-**	**-**	**-**
Grand total	**1344627**	**1903601**	**2471282**	**26682450**	**11637734**	**191724**	**307832**	**28203**	**7068**

* Sum of the only 4 PAHs reported in NPRI 2007 summary and available for cross-industry comparison. These are PAHs listed as probable human carcinogens. Total reported PAH emissions for oil sands operations, mainly non-carcinogenic PAHs, was 311 kgs in 2007, comparable PAH numbers were not summarized in NPRI.

**Reported Pb emissions for oil sands are summed from individual plant reporting which exceeds the 776 kg reported in the NPRI 2007 summary of industry categories.

***Reported Cd emissions for oil sands are taken as 134 kg from the NPRI 2007 summary of industry categories as this is higher than the sum from individual oil sands plant reporting.

Table 7.2b 2008 Total air pollutants emissions for Canada highlighting oil sands industry emissions

Sectors	$PM_{2.5}$ (tonnes)	SO_x (tonnes)	NO_x (tonnes)	VOC (tonnes)	CO (tonnes)	PAH 4* (kg)	Pb (kg)	Cd** (kg)	Hg (kg)
Industrial Sources									
Abrasives Manufacture	6	-	-	31	5	-	-	-	-
Aluminum Industry [sum PAH: 20% BC; 80% PQ]	5673	68190	2058	1579	384014	41293	-	-	30
Asbestos Industry	11	174	70	-	34	-	-	-	-
Asphalt Paving Industry	1624	927	1223	4563	4631	15.2	1309.7	25.8	23.7
Bakeries	3	-	-	8538	-	-	-	-	-
Cement and Concrete Industry	8373	31303	38008	302	17168	0.9	719.6	23.6	274.5
Chemicals Industry	1326	13633	19120	12868	14951	28.8	434.5	3.4	46.6
Mineral Products Industry	599	933	422	225	3663	-	-	-	-
Foundries	5562	95	155	573	52509	-	381.2	0.1	-
Grain Industries	3902	213	1151	2265	345	-	-	-	-
Iron and Steel Industries	2593	26976	12736	1126	35562	457.8	5933.7	313.5	915.5
Iron Ore Mining Industry	1495	18300	14561	59	23204	15.4	1529	27	91
Mining and Rock Quarrying	11911	4903	15451	2467	8883	-	10781	3.7	17.4
Non-Ferrous Smelting and Refining Industry [Sox: 63% MB; 31% ON]	2236	570302	3505	67	15333	0.36	196633	19638	1009
Pulp and Paper Industry	12304	41082	33948	15853	65838	171.2	1932	280.8	50.7
Wood Industry	5005	2251	11577	60878	337799	1.7	197.1	5.8	0.3
Upstream Petroleum Industry (except oil sands)	7332	175205	406961	379534	446821	-	-	-	-
Oil Sands Industry	**1645**	**118178**	**37317**	**59435**	**25763**	**4**	**760.9**	**136**	**85**
Oil Sands in situ extraction and processing	255	9539	11976	2140	7352	-	-	47.2	7.5
Oil Sands mining extraction, processing, and upgrading	1390	108638	25341	57294	18410	3.5	760.9	89.2	77.4
Downstream Petroleum Industry	2628	79327	28096	45424	22549	38.8	460.9	150.2	53.3
Petroleum Product Transportation and Distribution	161	1427	29933	331	16765	-	-	-	-
Other Industries	2691	7032	8464	47945	7485	8.7	2091	406.8	143.1
Total Industrial Sources (not incl. Electric Power Gen. Utilities)	**77080**	**1160440**	**664753**	**644063**	**1483321**	**42035**	**223163**	**21015**	**2739**
Total Industrial Sources + Electric Power Generation Utilities	**84007**	**1591053**	**891940**	**645860**	**1519487**	**42044**	**226007**	**21442**	**4320**
Oil Sands as a % of Total Industrial & Electric Power Generation	**2.0%**	**7.4%**	**4.2%**	**9.2%**	**1.7%**	**0.01%**	**0.3%**	**0.6%**	**2.0%**
Oil Sands rank among industry & power generation categories	**#12**	**#4**	**#4**	**#3**	**#7**	**#8**	**#8**	**#6**	**#5**
Non-industrial sources									
Commercial fuel combustion	2420	35081	29794	1212	15895	2.8	564	289	39
Electric power generation (utilities)	6928	430612	227187	1797	36166	8.7	2844	427	1580
Coal	4292	407744	167181	484	15055	0.1	2051	263	1498
Total non-industrial sources	**118421**	**476966**	**302731**	**158366**	**764246**	**56012**	**5187**	**1211**	**1725**
Total mobile sources	**62262**	**93285**	**1165046**	**529980**	**6746884**	**1761**	**44299**	**119**	**2**
Total incineration	**460**	**2079**	**2140**	**1341**	**4858**	**-**	**951**	**36**	**1255**
Total miscellaneous	**9424**	**0**	**34**	**446756**	**3803**	**1**	**1605**	**63**	**619**
Total open sources	**850486**	**1041**	**6270**	**330516**	**233839**	**1089**	**2115**	**58**	**688**
Total natural sources	**174674**	**147**	**185445**	**24249699**	**2054992**	**75741**	**-**	**-**	**-**
Grand total	**1292877**	**1733959**	**2326419**	**26360720**	**11081942**	**176640**	**277319**	**22502**	**7028**

* Sum of the only 4 PAHs reported in NPRI 2008 summary and available for cross-industry comparison. These are PAHs listed as probable human carcinogens. Total reported PAH emissions for oil sands operations, mainly non-carcinogenic PAHs, was 1093 kgs in 2008, comparable PAH numbers were not summarized in NPRI.

**Reported Cd emissions for oil sands are taken as 136 kg from the NPRI 2008 summary of industry categories as this is higher than the sum from individual oil sands plant reporting

7.3 Ambient Air Quality

The large number of oil sands operation emission sources and the large quantity of air pollutants that are emitted by individual operations clearly suggest grounds for concern about air quality in the region. Since 1998, the Wood Buffalo Environmental Association (WBEA) has maintained a regional air quality monitoring network of 15 stations, each with a variety of continuous air monitoring instruments. These data can be accessed via the Clean Air Strategic Alliance (CASA) data warehouse (www.casadata.org/) which provides data from all sites after they have undergone quality control audits. Virtually real time (hourly) monitoring data (raw data, not subject to quality control) is available on the Alberta Environment website (www.envinfo.gov.ab.ca/AirQuality/). The CASA data warehouse was searched to determine the number of times over the past decade when Alberta ambient air quality objectives were exceeded at a selection of WBEA sites (Table 2.2). Anzac is a hamlet south of Fort McMurray which is influenced by conventional oil and gas activity (gas plants), but is somewhat remote from major surface mining oil sands operations. Fort McMurray is a city of approximately 64,000 located more than 30 km south of the closest major oil sands operations. Fort McKay is a First Nations settlement located amidst several major oil sands developments and is the community most vulnerable to air quality impacts from current oil sands development. Fort Chipewyan is a First Nations settlement more than 150 km downstream (with respect to the Athabasca River) of any major surface mining oil sands developments.

Table 7.3 Number of times air quality objectives were exceeded during January 1, 2000, to February 28, 2010

	SO_2			NO_2			$PM_{2.5}$	CO		O_3		H_2S	
Location	**1h**	**24h**	**year**	**1h**	**24h**	**year**	**24h**	**1h**	**8h**	**1h**	**8h**	**1h**	**24h**
Ft Chipewyan	0	0	0	0	0	0	**6**	n/a	n/a	0	0	n/a	n/a
Fort McKay	**1**	0	0	0	0	0	**9**	n/a	n/a	**1**	0	n/a	n/a
Lower Camp*	**1**	0	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**412**	**85**
Mildred Lake*	**6**	0	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**1199**	**208**
Mannix*	**25**	**3**	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**813**	**134**
Fort McMurray, Athabasca Valley	0	0	0	0	0	0	**12**	0	0	0	**2**	n/a	n/a
Fort McMurray Patricia McInnes	0	0	0	0	0	0	**12**	n/a	n/a	0	0	0	0
Anzac, south of Fort McMurray	0	0	0	0	0	0	**4**	n/a	n/a	**1**	0	n/a	n/a
Air quality objective, $\mu g/m^3$ except as noted	450	150	30	400	200	60	30	15 mg/m^3	6 mg/m^3	160	130	14	4

*industrial sampling sites adjacent to the original Suncor and Syncrude oil sands developments

Source: CASA (www.casadata.org/)

For sampling sites near communities, $PM_{2.5}$, had a small number of occurrences with values in excess of air quality objectives at every site with data over the past decade. The two Fort McMurray sites showed the largest number of days above the air quality objective, but this parameter is subject to

influences from many different human activities including traffic and local burning, so these air quality changes cannot be directly attributed to oil sands development.

There was a single one-hour SO_2 excess value at Fort McKay and a number of one hour excess values at the industrial sites, with three 24 h excess values over 10 years at the Mannix site. This parameter, which is a major pollutant emission from oil sands, was only exceeded at the industrial sites but not at any community site over the past decade.

There was no excess value for NO_2 at any site. O_3 is produced by photochemical reactions between NO_x and VOCs; it is not emitted by pollution sources and O_3 does not suggest air quality impacts from oil sands developments. CO values were not reported for enough of the sites to be useful.

The poorest record for air quality appears for the odorous pollutant H_2S with several hundred 1 hour and 24 hour excess values reported at the industrial sampling sites. The large increase in excess values occurred since 2006 and is believed to be linked with reclamation activities at the original Suncor Tar Island tailings pond (Kleiss 2010). The criteria level for H_2S (1 hour max of 0.010 ppmv or 14 $\mu g/m^3$) is set for odour detection and is a 1000-fold lower than the lowest observable adverse effect level (LOAEL) in humans of 15 to 30 mg/m^3 (WHO 2000). Although H_2S measured at Fort McKay does not show the exceedances recorded at the industrial monitoring sites, the location of Fort McKay is such that odour impacts (better represented by TRS) have most certainly been experienced in recent years.

Wise management of air quality should not support allowing excellent background air quality to be degraded up to the objectives which are set, in part, to reflect what is attainable for urban areas given the ubiquitous propensity of human activity to release air contaminants. Thus, the small number of occasions that air quality objectives have been exceeded does not, by itself, mean that there are no air quality impacts or concerns for oil sands developments. A recent review of 5 to a maximum of 10 years (1998 to 2007) of WBEA air quality data (Kindzierski et al. 2009) assessed whether there were any trends in air quality parameters at each site. This review did not include the recent dramatic increase in H_2S exceedances discussed above.

Among these trends, those which may indicate air quality trends that may be attributable to oil sands development include: increases in NO_x and a small increase in TRS at Fort McKay, an increase in H_2S at Mildred Lake, an increase in SO_2 at the Mannix site (Suncor main entrance), an increase in NO_x at Fort McMurray (Patricia McInnes), small increases in THC and TRS at Barge Landing (north of Fort McKay), a small increase in THC at the Albian mine site, a small increase in H_2S at Lower Camp (Syncrude), an increase in NO_x and THC at the Millenium Mine (Suncor expansion), and a small increase in TRS at Syncrude UE1 (between Syncrude and Fort McKay). While these trends do not indicate pervasive ambient air pollution, they support a need for vigilance and the use of BATEA for controlling air pollutant emissions in the area.

Concerns about emissions of PAHs from oil sands development were raised in a recent study by Kelly et al. (2009). Although they did not collect or analyze air samples directly, they collected snow samples during the winter of 2008 and based on analysis of particulate and dissolved PAHs in melted snow, they concluded that oil sands developments within a 50 km radius of the original Suncor and Syncrude oils sands facilities (and possibly other newer developments in the region) had emitted

~1,200 kg of particulate PAH and ~500 kg of dissolved PAH for a total of ~1,700 kg of emitted PAH. In 2008, Suncor and Syncrude reported estimated combined emissions of over 1,000 kg of PAHs (NPRI 2010). Because 28 to 42% of the compounds Kelly et al. (2009) reported as PACs were dibenzothiophene homologues which are not generally considered to be PAHs and were not reported as PAHs by either Syncrude or Suncor, the total estimates for PAH emissions are remarkably close, much closer than would be expected given the extremely different methods of data collection and calculation of contaminant loading between these two data sources.

Kelly et al. (2009) inferred from regional water samples that dissolved PAHs[3] were higher in flowing waters (tributaries and the Athabasca River) downstream of oil sands developments, inferring that air emissions and surface disturbances of oil sands developments were responsible for increased concentrations of dissolved PAHs. Kelly et al. (2009) introduced their paper by mentioning concerns among residents in Fort Chipewyan about elevated cancer rates. In their supporting information, they elaborate on these concerns by referencing the studies on cancer rates in Fort Chipewyan, noting that concerns about cancer are controversial before noting that: "*Oil sands contain a broad array of the chemicals typical of petroleum, including three- to five-ringed polycyclic aromatic hydrocarbons (PAHs) and a variety of toxic metals (9–11). Many of these constituents are highly toxic, some are carcinogenic, and all can be distributed widely via gases and dust originating from oil sand mining and processing*." In this quote, the references 9–11 refer to toxic metals[4], so the discussion by Kelly et al. quoted above about carcinogenic PAHs was not supported by cited references or data that would justify this mention of carcinogenic PAHs in the context of concerns about excess cancer in Fort Chipewyan.

7.4 Air Quality Issues Associated with Oil Sands Development

Intervenors at public hearings have expressed concerns about NO_x emissions from combustion sources at oil sands facilities. These concerns combined with findings of Kindzierski et al. (2009) of an increase in NOx at Fort McKay and at the Millenium Mine (Suncor expansion) suggest that NO_x emissions are an important air quality issue. AENV has a policy of requiring Best Available Technology Economically Achievable (BATEA) and they contracted the Alberta Research Council to perform a technology review to help define BATEA for the control of NO_x emissions (ARC 2007). Stakeholders should reasonably expect that AENV will implement this policy and require oil sands emitters to use current BATEA when issuing EPEA approvals initially and when approvals are renewed (at least every 10 years). This is not an issue over which industry should hold any veto if AENV is to maintain credibility of its regulatory policy. The observed increase in NO_x at the Fort McMurray (Patricia McInnes) site may reflect emissions associated with increased traffic on Highway 63 north to the oil sands facilities rather than any influence of emissions from the oil sands facilities.

[3] Sampling of tributaries and the Athabasca River by Kelly et al. (2009) was done by polyethylene membrane devices which collect only dissolved PAHs.

[4] Reference 9 (Akre et al. 2004) addressed the occurrence of PAHs in sediments of the lower Athabasca River, reference 10 (Colavecchia et al. 2004) addressed the toxicity of oil sands constituents to early life stages of fathead minnows, and reference 11 (Headley et al. 2005) addressed inorganic chemicals in tributary waters to the Athabasca River.

Odours in the vicinity of oil sands facilities have been a concern among residents of Fort McKay. The analysis of Kindzierski et al. (2009) indicated a small increase in TRS at Fort McKay, a small increase in TRS at Syncrude UE1 (between Syncrude and Fort McKay), an increase in H_2S at Mildred Lake, a small increase in H_2S at Lower Camp (Syncrude), and small increases in TRS at Barge Landing (north of Fort McKay), all consistent with odour problems associated with reduced sulphur compounds. These concerns may also be related to observations of small increases in THC at Barge Landing (north of Fort McKay), an increase in THC at the Millenium Mine (Suncor expansion), and a small increase in THC at the Albian mine site. The problems of excess emissions of H_2S and TRS are evident at sites near the original Suncor and Syncrude sites which have had documented odour problems since 2007. The proximity of these sites to Fort McKay validates the concerns that community has with odours from oil sands operations. Odours can be caused by non-sulphur compounds such as those which may be part of THC even though sulphur odour agents usually have the lowest detection thresholds.

The subject of non-point (fugitive) emissions of air contaminants from mines and tailings ponds is highly uncertain and currently available estimates are unlikely to be entirely valid. There is clearly scope for extensive, targeted data gathering to validate actual emissions from these sources. Likewise, the overall emissions inventory data reported to NPRI should be validated to insure the integrity of that data base.

As oil sands industrial development encroaches more closely on Fort McKay, noise is likely to become an issue of increasing concern. In anticipation of noise concerns the ERCB needs to review the adequacy of its industrial noise policy because AENV has largely relied upon the ERCB to manage this nuisance. Currently, noise management is covered by ERCB Directive 38 (ERCB 2007) which states: "*This directive attempts to take a balanced viewpoint by considering the interests of both the nearby residents and the licensee. It does not guarantee that a resident will not hear noises from a facility; rather it aims to not adversely affect indoor noise levels for residents near a facility. The directive sets permissible sound levels (PSLs) for outdoor noise, taking into consideration that the attenuation of noise through the walls of a dwelling should decrease the indoor sound levels to where normal sleep patterns are not disturbed.*"

The observation of Kindzierski et al. (2009) of an increase in SO_2 at the Mannix site (Suncor main entrance) might signal a concern given the magnitude of SO_2 emissions from oil sands upgrading facilities, but the trend towards lower allowable SO_2 emissions is such that this finding of an upward trend at only one location adjacent to the original oil sands plant, by itself, may not warrant substantial concern. There have been concerns about acidifying emission affecting lakes in the region and in northern Saskatchewan. The potential for acidification of regional lakes is being extensively monitored (RAMP Implementation Group 2010) and based on eight years of data, there is no clear or consistent evidence of acidification. Because 60% of lakes in the region are considered highly sensitive or moderately sensitve to acidification this air quality issue demands continued vigilance.

Saskatchewan Environment has implemented an air monitoring program with the assistance of equipment provided by Alberta Environment and these agencies along with the ERCB have signed a MoU on management of acid deposition in the region (Maqsood et al. 2006). Monitoring at 10 locations ranging from 25 km east of the Alberta–Saskatchewan border to 235 km east showed that

maximum and six-month average NO_2 values were highest at the 25 km site and were elevated up to 150 km east of the Alberta border. In contrast, for 14 locations up to 512 km east of Alberta (within 100 km of the Manitoba–Saskatchewan border), there was no evidence of SO_2 influence from Alberta, but there was clear influence of elevated SO_2 within 180 km of the Manitoba border, most likely reflecting impacts from the Hudson's Bay Mining and Smelting complex at Flin Flon which accounted for almost 12% of all SO_2 emissions in Canada for 2008 according to NPRI.

Monitoring and modeling of 424 lakes in northwest Saskatchewan for 2002 found that calculated acidification loading exceeded critical loads for 33% of the lakes (Das 2009). Updating 2007 monitoring data for lakes of the Environment Canada national critical loading map revealed that northwest Saskatchewan is among the most acid-deposition sensitive regions in Canada. While the SO_2 monitoring is somewhat encouraging for the influence SO_2 emitted from the oil sands may be having on northwest Saskatchewan, the impact of NO_2 emissions from the oil sands is clearly a concern and the issue of lake acidification of northwest Saskatchewan is a critical example of a cumulative environmental impact from oil sands which must be managed. The findings about elevated NO_2 levels in Saskatchewan further justify AENV effectively implementing its BATEA policy for emissions control.

The concerns raised by Kelly et al. (2009) about PAHs being emitted from oil sands facilities and their potential environmental and public health impacts suggest an issue that should be addressed in a rigorous manner. This subject is discussed further in Section 8.4 on water quality and Section 10.4 on public health impacts. The concerns raised by Kelly et al. (2010) about elevated trace metal concentrations in snowfall, the Athabasca River and tributaries suggest that some trace metal monitoring of ambient air quality in the region aimed at quantifying airborne emissions from oil sands operations would be prudent.

8. WATER QUANTITY AND QUALITY

8.1 Introduction

All aspects of the oil sands developments including surface mining, in situ extraction, and bitumen upgrading are dependent on water. The production of 1 m^3 of synthetic crude oil (upgraded bitumen) requires about 2.5 m^3 of water by surface mining and about 0.5 m^3 of water by in situ recovery (Section 4.4). Oil sands mining and processing activities may impact the aquatic environment by: withdrawal of surface water and groundwater, loss of fish and benthic invertebrate habitat through removal of streams or rivers, and reductions in water quality through leaching of contaminants from tailing ponds and in situ operations into ground water and rivers (Gould Environmental 2009). This section will focus on how current and anticipated activities within the oil sands mining operations impinge upon the issues of water quality and quantity. The key questions to be addressed include whether oil sands development will jeopardize the sustainability of water resources in northern Alberta and whether impacts on water resources may represent a constraint to further development within the oil sands region.

Consideration of water issues will be addressed in terms of quantity and quality as they affect surface water and groundwater systems. Assessment of both surface water and groundwater are integral to the water-related requirements attached to EPEA approvals for developments in the oil sands regions (Appendix A4). These two water compartments are often treated separately when addressing environmental issues related to the oil sands, but both systems are intimately linked and long-term management of water issues should be based on an integrated surface water–groundwater approach. In particular, surface mining operations are required to contain oil sands process-affected wastewaters (OSPW) within on-site tailings ponds with re-use in process (mainly for extraction) to the maximum extent possible. Consequently, the ability of process-generated waterborne contaminants to reach the off-site aquatic environment must occur by means of groundwater flow, making this route an issue of major concern. There is also a need to consider water-related issues in relation to other environmental compartments. For example, bacteria in the tailings ponds produce methane, a potent greenhouse gas.

8.2 Surface Mining

Surface mining is used when the thickness of material overlying the oil sand deposit is less than 75 m (Section 4.2). The current and actively developed surface mining project area corresponds to approximately 1.3% (total potentially surface mineable area is 3.3%) of the total area in Alberta containing known bitumen deposits, while in situ recovery is required for the remaining 96.7% of known bitumen deposits (ERCB 2010). During surface mining, the overlying material is removed to directly access the oil sands and the resulting excavation must be dewatered to allow mining operations. Depressurization of the surrounding subsurface units can be required to ensure stability of excavation slopes. During overburden removal, water whose quality is not negatively impacted by contact with the oil sands formation is released to receiving streams, as described for the Kearl Oil Sands Project (Imperial Oil Resources 2005). Otherwise, water that comes in contact with the oil sands is stored in the tailings area and reused for bitumen extraction.

8.2.1 Water Quantity

Water quantity issues are those that affect the volumes of surface water and groundwater. For rivers and streams, volumes are often expressed as flow rates, which is the volume of water flowing in the river or stream for a given time interval. For groundwater, variations in the volume of water stored can be determined from water level measurements in wells and piezometers.

During surface mining operations, dewatering and depressurization are achieved by drilling wells in the subsurface and pumping groundwater. Groundwater extracted during dewatering is stored in the tailings area and used for bitumen extraction. As a result of extraction, groundwater levels are lowered in the vicinity of the excavation to an extent that depends on hydraulic properties (permeability) of subsurface materials and pumping rates. For example, groundwater pumping from the Basal Aquifer at Muskeg River Mine has resulted in decreases of 40 m in groundwater levels at some nearby observation wells (Komex International Ltd. 2004). The Basal Aquifer corresponds to the lowermost part of the McMurray Formation, below the oil sands layer, and is assumed to be the only continuous regional aquifer in the surface mining area (Bachu et al. 1993; Imperial Oil Resources 2005). Reduced groundwater levels lead to reduction in groundwater flow to the surface water bodies that are in hydraulic contact with groundwater, thereby reducing water inflow into these bodies. Removal of overburden also modifies near-surface groundwater flow dynamics, which in turn impacts surface water bodies and can affect recharge rates for deeper aquifers. Composition of overlying material, or overburden, is spatially variable for the region covered by surface mining, but coarse material such as sand and gravel can be present, for example in buried valleys. This coarse material has a high permeability and could represent a local aquifer. Removal of that material represents a loss of a potential local groundwater source of drinking water.

8.2.1.1 Lakes and Wetlands

Interactions between groundwater and surface water, and the water exchange rates, have to be addressed. For example, there are several lakes and wetlands in the Fort McMurray region that may be potentially affected by groundwater extraction from oil sands operations. The flow dynamics between the groundwater and these lakes and wetlands are not well understood and must be better defined to predict the impact of oil sands operations. Most studies of groundwater exchange in the Boreal Plains ecosystems of Alberta have focused primarily on upland dominated watersheds. These watersheds are characterized by low precipitation and evaporation rates, dry soils, and forested hillslopes (Devito et al. 2005). Water inflow into lakes in upland dominated watersheds is predominately from groundwater, with surface water runoff accounting for a much smaller fraction (Ferone and Devito 2004; Smerdon et al. 2005; Smerdon et al. 2007). More work is required to quantify the flow dynamics for these watersheds.

Schmidt et al. (2010) present the first reported estimates of groundwater contributions for wetland dominated watersheds, which dominate northeastern Alberta in the vicinity of oil sands developments near Fort McMurray. They state that there have been several studies to evaluate the effect of ongoing mining and processing activities on the aquatic ecosystems in the region, including some that try to establish individual water budgets for lakes using isotope-based approaches (e.g., Bennett et al. 2008).

Those studies, however, did not distinguish between surface runoff and groundwater inflow into the lakes, and gaps still exist in quantifying groundwater and surface water exchange. Schmidt et al. (2010) estimated groundwater discharge to two small lakes near Fort McMurray from measurements of the naturally-occurring radioisotope Radon-222. Comparing a radon mass balance with a stable isotope mass balance, they estimate the contribution of groundwater to the total inflow into both lakes, and show different results with groundwater accounting for 0.5% to about 14% of the total annual water inflow. Lower groundwater inflow rates are attributed to a larger drainage area/lake area ratio. They conclude that further work is needed to better quantify the groundwater–surface water flow dynamics in the Fort McMurray region, to help assess the impact of oil sands operations.

8.2.1.2 Rivers

Surface mining operations require water to extract bitumen from the oil sands formation. Water used for extraction comes either from surface water, most commonly the Athabasca River, or from groundwater. One requirement in evaluating the impact of the oil sands operations on river flow is to establish a baseline, which is the state of the river prior to the oil sands operations. There have been three major federal and provincial environmental research programs in the oil sands region dating back to 1975: the Alberta Oil Sands Environmental Research Program, the Northern River Basins Study, and the Northern Rivers Ecoystem Initiative. Within these programs, the water quantity and quality of the main rivers in the oil sands region have been monitored, providing water quality and monitoring data that can help establish the baseline. Examples of rivers for which baseline data for river flow rates exist are the Athabasca River (AENV 2007) and the Muskeg River (AENV 2008).

Current estimates are that between 50% and 75% of the total volume of water used comes from the Athabasca River (CAPP 2009). The most common concern with using the water from the Athabasca River is the reduction of its flow rate. AENV, in collaboration with the federal Department of Fisheries and Oceans, has released a water management framework to regulate the use of the Athabasca River water, to meet in-stream flow needs (AENV 2007), which correspond to the amount of water, flow rate, water level, and water quality that is required in a river or other body of water to sustain a healthy aquatic ecosystem (Table 8.1).

Table 8.1 Phase 1 Water Management Framework for the Athabasca River

Flow condition	**Environmental Implication**	**Management Action**
Green Zone : when river flow is above the cautionary threshold (CT), which is a maximum of HDA80[1] or Q90[2]	Flows are sufficient. Impacts to aquatic ecosystem are negligible.	All licensees operate normally and operate within the conditions of their licences. Maximum cumulative withdrawal is 15% of instantaneous flow. Not likely to result in impacts to fish habitat, not likely to require a Fisheries Act Authorization.
Yellow Zone: when river flow is below the CT, but above Q95[3]	Natural low flows occurring. Assume aquatic ecosystem may experience stress from a 15% withdrawal.	Total cumulative diversion rate is 10% of the average of the HDA80 and Q95. Maximum cumulative withdrawals: Winter = 15 m^3/s, Spawning = 5% of the HDA80 flow or 34 m^3/s, whichever is less Summer = 34 m^3/s. Recent and new licences will include conditions that mandate incremental reductions. Is likely to result in impacts to fish habitat and may require a Fisheries Act Authorization.
Red Zone : when river flow is below Q95	Natural low flows may limit habitat availability. Increased duration and frequency of habitat loss due to water withdrawals should be minimized	Mandatory reductions and use of storage. Total cumulative diversion rate is 5.2% of historical median flow in each week. Maximum cumulative withdrawals: Winter = 15 m^3/s Spawning = 5% of the HDA80 flow or 34 m^3/s, whichever is less Summer = 34 m^3/s. Applies to all licences in a variety of ways. Is likely to result in impacts to fish habitat and may require a Fisheries Act Authorization.

[1]: HDA80: Amount of habitat area that is exceeded for 80% of all observations.
[2]: Q90: Amount of river flow that is exceeded for 90% of all observations.
[3]: Q95: Amount of river flow that is exceeded for 95% of all observations.

Source: AENV 2007

According to the management framework, the river flow rate and the habitat area must be continuously monitored and compared to threshold values that are defined from the statistical evaluation of past measurements. If measured flow rates and habitat area decrease below the thresholds, voluntary or mandatory reductions in river water abstraction are put in place. To plan for potential reduction in river water abstraction during low flow periods, oil sands projects have the option of storing water withdrawn during high flow periods for use during critical low flow. Other actions which can be taken to reduce water abstraction from the river are to reduce water use and increase water recycling by better tailings dewatering.

AENV (2004) studied trends in historical annual flows for major rivers in Alberta. This report analyzed flow data at Athabasca (over 200 km upstream of Fort McMurray) for all available annual data (1913–1930, 1938–1940, and 1942–2001) and found no statistically significant trend ($p<0.05$) but a mildly positive (increasing flow) correlation over this 88 year period. Another trend study for the Athabasca River Basin was conducted by Jacques Whitford (2008), who analyzed monthly flow data from four Water Survey of Canada stations. Two stations were located on the Athabasca River, at Athabasca and Fort McMurray, and two other stations were for major tributaries, the Clearwater and the Pembina Rivers. The flow records cover the periods 1957–2006, 1913–2006, 1957–2006, and 1954–2006 for the Athabasca, Fort McMurray, Clearwater, and Pembina stations, respectively, but some gaps exist in the records. The Jacques Whitford (2008) analysis indicates there is a statistically significant linear trend of decreasing flow rates since the mid-1970s. A stronger linear trend is observed for the downstream station at Fort McMurray compared to the Athabasca station where the linear trend is the smallest. That trend is correlated with a decrease in annual precipitation in the prairie provinces for the same period, but the study does not conclude that reduced precipitation is the only cause for decreasing flow rates and suggests that other factors may play a role.

Squires et al. (2010) proposed a method to establish a baseline for the Athabasca River Basin from historical data to allow for evaluation of the cumulative impact of all human activities on the river. Using data from two periods, 1966–1976 and 1996–2006, they report a statistically-significant and substantial decrease in river flow rate between these two periods. In the river reach from Fort McMurray to Lake Athabasca, they report a 25.6% decrease in average high flows (May to August) and a 30% decrease in average low flows (September to April) between these two periods. They found an increase in dissolved sodium, sulphfate, chloride, and total phosphorous concentrations in the river for the period 1996–2006 compared to 1966–1976. Identifying the causes for these variations is an obvious need for current environmental monitoring programs in the oil sands region.

Current allocation of water from the Athabasca River, for all usages, is 3.5% of the total annual average river flow, with allocations for oil sands mining projects accounting for about 2.2% of total flow and actual water usage in 2005 about 0.7% of the total annual average river flow (AMEC 2007). That percentage changes depending on the value used for total flow. For example, in their analysis of flow data for the Athabasca River, Jacques Whitford (2008) reported that the historical low flow for the Athabasca River is 97.8 m^3/s. That value is based on the seven-day average low flow recorded for the period 1957–2006 in the Athabasca River at Fort McMurray. Water allocated for the oil sands for projects active in 2006 corresponded to 11.6% of the historical low flow, while allocation for existing

and planned projects in 2006 represented 15.9% of the historical low. In light of the observed continuous decline in flow rates of the Athabasca River, whose cause remains to be identified, the allocated percentage of total flow would increase with time even if water use for the oil sands remained constant. This variability in flow rates must be monitored and responded to in real time by being accounted for in the water management framework.

A hydrologic assessment was conducted in 2009 as part of the RAMP assessment activities (RAMP, 2009). These studies revealed no changes in water discharge for the Lower Athabasca River and Athabasca River delta and six of seven watersheds that were evaluated. For the Tar River Watershed, the mean open water discharge and annual maximum daily discharge rates were 18.5 and 18.8% lower than the baseline (RAMP 2009). It is not clear what follow up will be conducted at this site beyond further monitoring.

8.2.1.3 Groundwater

While a framework has been proposed to manage, and potentially limit, water extraction from the Athabasca River, there is no evidence of a similar framework to limit groundwater extraction related to surface mining and thereby limit the permitted groundwater level declines. To assess the impact of operations on groundwater, current practice is that environmental impact assessments for individual oil sands developments include hydrogeological studies designed to identify the local groundwater flow dynamics and predict the impact of operations (dewatering, depressurization) on future groundwater levels, flow directions, and surface water-groundwater interactions. Although results from these studies that concern predictions of groundwater quality can be compared to water quality criteria such as drinking water guidelines, there are no equivalent guidelines for groundwater quantity, as demonstrated, for example, for the Kearl Oil Sands Project environmental impact assessment (Imperial Oil Resources 2005).

Current practice to assess the impact of surface mining on surface water and groundwater usually relies on predictive modelling. There can be a high level of uncertainty in predictions because of the uncertainty in the knowledge of input parameters for the models. The uncertainty is often higher for groundwater systems, whose heterogeneities cannot be adequately quantified unless substantial characterization is undertaken. Separate models are used to assess impacts on surface water and groundwater systems, although any impact on one system will influence the other. Integrated models that consider coupled surface water and groundwater flow dynamics would provide a more appropriate representation of the natural flow system. In the longer term, it will be important to consider the input from the proposed end pit lakes (EPLs), which will become part of the natural flow system. Another important consideration will be changes in surface flow resulting from mining activities and how these may affect sediment transport.

Hydrogeological studies are conducted on a case-by-case basis and the cumulative impact of all surface mining on groundwater levels and flow rates are not quantified. The issue of cumulative impact is very often raised and one example is given in the review by Environment Canada of the Muskeg River Mine expansion application (Environment Canada 2006). However, a regional hydrogeological model (either conceptual or numerical) still has not been developed to address these cumulative

impacts. Anfort et al. (2001) presented the first hydrogeological study for the whole Alberta Basin, which is a large and complex system, but there has not been a regional hydrogeology study specific to the oil sands region since the report presented by Hackbarth and Nastasa (1979). A conceptual model of the hydrogeology of the Athabasca oil sands region is currently being developed by the Worley Parsons Komex consulting engineering firm (Dillon Consulting Limited 2008) and should contribute to a better assessment of cumulative impacts.

In contrast to surface water, groundwater flows at much smaller velocities. For example, groundwater typically moves at a rate of one meter per year (m/y) in permeable aquifers compared to water velocities of metres per second (m/s) in the Athabasca River. Therefore, the time scale for groundwater pollution is much longer than it is for surface water and, depending on the hydrogeological context, it can take decades for groundwater pollutants to migrate from a source to a receptor. This reality means that groundwater monitoring will likely be necessary for years or decades after specific operations cease, especially if the potential source of contaminants is still present and keeps releasing contaminants to the environment.

A recent report by CEMA (2010) provides the needed steps towards a regional geological and hydrogeological framework. This initial study has summarized the current understanding of the hydrogeology of the region, identified knowledge gaps and proposed plans for the monitoring network. This report presents the most recent overview of the regional geology and hydrogeology of the oil sands region. The main geological units and hydrostratigraphic units are presented in Tables 8.2 and 8.3, respectively. Regional groundwater flow directions are predominantly controlled by topography, with recharge from ground surface occurring in upland areas and discharge to the surface (for example in rivers and streams) occurring in adjacent low lying areas and river valleys (Figure 8.1). The statement by CEMA (2010) that the study by Hackbarth and Nastasa (1979), which is now more than 30 years old, is still one of the more extensive regional hydrogeological studies in the region is indicative of the lack of an integrated regional groundwater framework for the region.

Table 8.2 Classification of major regional geographical layers

Period	**Group**	**Formation**	**Member**
Quaternary	–	–	–
Major gap in geologic sequence (unconformity/erosion surface)			
Upper Cretaceous	Colorado	La Biche	
		Pelican	
		Joli Fou	
Lower Cretaceous	Mannville	Grand Rapids	
		Clearwater	Wabiskaw
		McMurray (Oil Sands)	Upper
			Middle
		Basal McMurray	Lower
Major gap in geologic sequence (unconformity/erosion surface)			
Middle Devonian	Beaverhill Lake	Waterways	Mildred Lake
			Moberly
			Christina
			Calumet
			Firebag
		Slave Point	
		Fort Vermillion	
	Elk Point	Watt Mountain	Upper
		Muskeg	
		Prairie Evaporite	
		Methy (Winnipegosis)	
		Contact Rapids	Lower
		Cold Lake	
		Ernestina Lake	
		Lotsberg	
		McLean River	
Lower Devonian		La Loche (Granite Wash)	
Major gap in geologic sequence (unconformity/erosion surface)			
Precambrian			

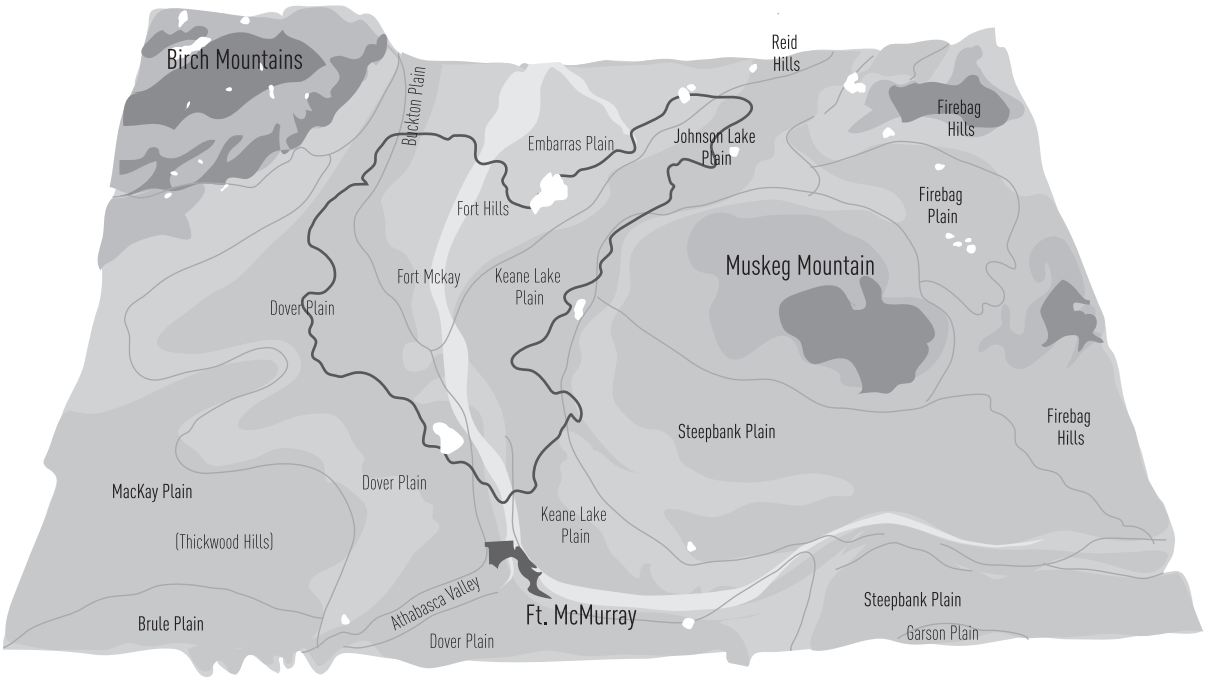
Source: CEMA 2010

Table 8.3 General regional hydrostratigraphy of the oil sands region

Period	**Formation**	**Classification**	**Hydrostratigraphic System**
Quaternary	Sands and gravels Till	Aquifer Aquitard	Pleistocene channels and surficial sands
Lower Cretaceous	Grand Rapids Formation	Aquifer	McMurray–Wabiskaw Aquifer/Aquitard System
	Clearwater Formation	Aquifer/aquitard	
	McMurray Formation	Aquifer	
Upper Devonian	Grosmont Formation	Aquifer	Beaverhill Lake–Cooking Lake Aquifer System
	Ireton Formation	Aquitard	
	Cooking Lake Formation	Aquifer	
	Waterways Formation	Aquifer/aquitard	
	Slave Point Formation	Aquifer	
	Fort Vermillion Formation	Aquiclude	
Middle Devonian	Watt Mountain Formation	Aquitard	Prairie Watt Mountain Aquiclude System
	Prairie Evaporite Formation	Aquiclude	
	Methy Formation	Aquifer	
	Contact Rapids Formation	Aquifer/aquitard	Lower Elk Point Group Aquitard/Aquiclude System
	Cold Lake Formation	Aquiclude	
	Ernestina Lake Formation	Aquifer/aquitard	
	Lotsberg Lake Formation	Aquiclude	
	Granite Wash / La Loche	Aquifer	–
Precambrian	–	Aquiclude	–

Source: CEMA 2010

Figure 8.1 Conceptual regional groundwater flow patterns



Source: CEMA 2010 (modified from Andriashek and Atkinson 2007)

As part of that study, CEMA (2010) reviewed and assessed data from 1,500 monitoring wells and over 132,300 chemical analyses, which indicate highly-variable baseline groundwater quality in surficial and bedrock formations. Based on their review of the data and current regional understanding of groundwater quantity and quality, CEMA (2010) identified the following main knowledge gaps:

- *lack of sufficient temporal data in existing monitoring wells to determine historical trends for key indicators;*
- *limited monitoring coverage outside of the active mineable oil sands area;*
- *unknown degree of connectivity between certain aquifers and major water bodies (for example the Clark Channel, Kearl Channel, Fort Hills Channels) and wetlands;*
- *lack of data on hydraulic characteristics of most major channels;*
- *lack of geological data for most buried valleys (are they made of sand or till?);*
- *lack of surficial geology (soil media) on western side of study area;*
- *limited understanding of cross formational flow and groundwater surface water interactions;*
- *contribution from bedrock formations water to natural water bodies like the Athabasca River (loading of natural constituents versus industrial);*
- *lack of data on potential vertical variation of quality conditions in discrete water-bearing intervals and potential effects of bedrock water chemistry on near-surface sands and buried channels/valleys;*
- *insufficient information on Grand Rapids, Wabiskaw and Methy Formations to facilitate vulnerability mapping and management classification scheme; and*

- *limited information on the distribution of basal McMurray Formation beyond the central portion of the regional study area, further west and east.*

Clearly, the CEMA (2010) report is a first step. A commitment to complete future work is required to establish a regional groundwater framework. These findings also apply to in situ operations, whose impact on water is covered later in this section. Another example of a recent positive step to address water quality and quantity issues is the Water Management Plan for Cold Lake–Beaver River, which is presented in Appendix A5.

8.2.2 Water Quality

Water quality issues include those that affect surface water and groundwater as a result of surface mining operations. After bitumen has been extracted from the oil sands formation, the residual material composed of solids (sand, silt, and clay particles) and contaminated OSPW is discharged to tailings ponds. Because OSPW contains dissolved contaminants, the main concern associated with surface mining is that contaminants can reach the ground water and surface waters. Even if OSPW does not directly reach surface water, groundwater contaminated by the tailings ponds can be in hydraulic contact with surface water and thereby lead to its contamination.

8.2.2.1 Tailings Ponds

The conventional bitumen extraction process (see Chapter 4) results in large volumes of fluid tailings that are discharged to tailings ponds. The tailings will de-water producing a soft fines-rich suspension, known as mature fine tailings (MFT). Generally, tailings contain approximately 70 to 80 % weight basis (wt%) water, 20 to 30 wt% solids (sands, silt, and clays), and 1 to 3 wt% bitumen (Allen 2008a). The released water is reused in the oil sands extraction process (process water) although there are limits as reuse affects the extraction chemistry and leads to corrosion and scaling of extraction facilities (Section 4.2). Oil sands operations do not release extraction wastes to the environment; rather they contain all OSPW and fine tailings on site, primarily in large tailings or settling ponds. These are often constructed using overburden and tailings are retained by sand dykes constructed with drainage collection systems. Large settling basins are required during the operational phase of the mine, but eventually these containment structures must be reclaimed (ERCB 2009a). Current inventories indicate that the volume of fluid tailings (OSPW and MFT) are 720,000,000 m^3 in tailings ponds that cover an area of about 130 km^2 (ERCB 2009b). The area covered by tailings ponds is likely to increase with further expansion of oil sands mining operations unless new regulatory requirements on tailings management (ERCB 2009a) lead to accelerated reclamation to reduce the 40-year historical inventory of tailings.

Current practice in the design of tailings ponds is to operate interceptor ditches and wells to intercept water leaking from the ponds, and thereby to prevent its migration into groundwater or surface water systems. For tailings ponds located on the existing terrain (as opposed to tailings impoundments in mined out areas), dykes composed of permeable sand tailings have been constructed to contain the tailings and prevent off-site migration of OSPW. Because dykes are permeable, release of

contaminants from the tailings ponds can occur by migration of OSPW through the impoundment structure.

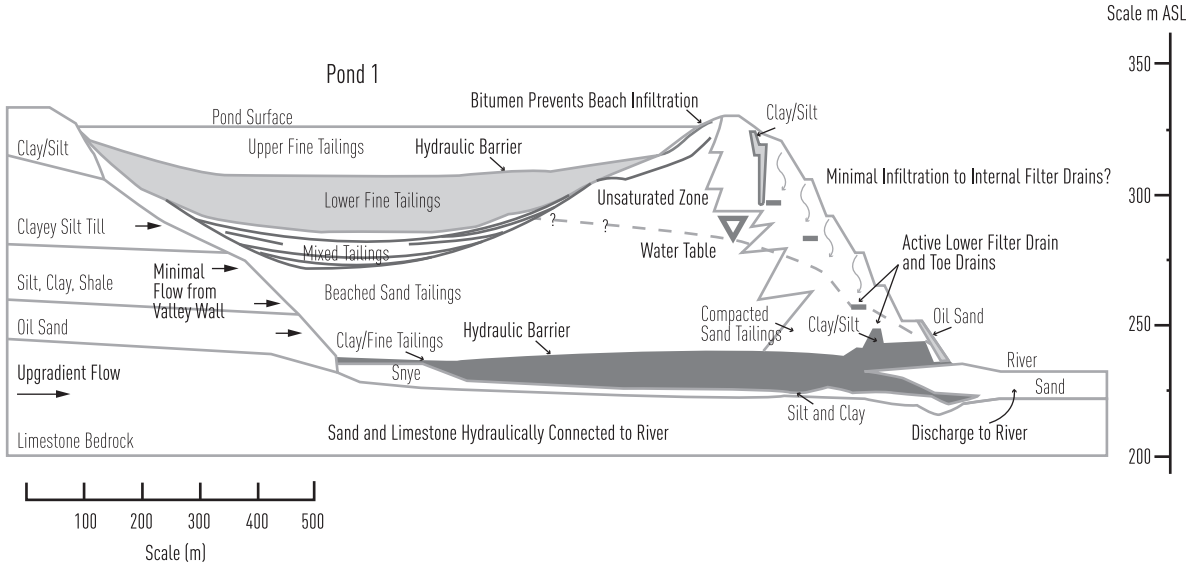
The approvals issued under the EPEA require that surface mine operators report on seepage of tailings release water into groundwater or surface water. For example, in the approval for the Suncor Energy Inc. Oil Sands Processing Plant and Mine issued in 2007, a bi-annual report must be submitted to document expected volumes of water release, flow regimes for surface and groundwater, downgradient or downstream effects, and any proposed mitigation.

Although seepage rates must be quantified, very few published data are available on the dynamics of groundwater flow and the fate of process water contaminants in the impoundment structure; therefore these processes remain largely unknown. In one such study, Ferguson et al. (2009) used field measurement and numerical modelling to investigate groundwater flow within the Tar Island Dyke impoundment structure at the Suncor Inc. site near Fort McMurray (Figure 8.2). They showed that pond foundation and impoundment structures were heterogeneous and composed of materials of different hydraulic properties, ranging from very permeable sands to low-permeability clay, all of which influence groundwater flow dynamics. A vertical cross-section through the tailings pond is shown in Figure 8.3 and illustrates the spatial variability of subsurface materials. Although the dykes separating the pond from the river are composed of permeable sand tailings, with a high potential for groundwater flow and therefore off-site migration, internal groundwater flow barriers (low-permeability material) greatly reduce off-site leakage through the Tar Island Dyke.

Figure 8.2 The Tar Island dyke—Note: This tailings pond had its inventory of MFT removed and replaced by sand in 2010 and was announced as having surface revegetated in September 2010.

Photograph courtesy of Jim Barker (University of Waterloo)

Figure 8.3. Vertical cross-section across tailings pond



Source: Ferguson et al. 2009

In another study of dykes, Mackinnon et al. (2005) investigated the migration of OSPW downgradient of the dyke at the Mildred Lake Settling Basin at the Syncrude mine. The seepage collection ditch at this facility was installed in the permeable sand at the toe-berm. Water samples collected at several locations along the potential migration path were used to demonstrate that OSPW reached the Lower Beaver Creek that flows along the edge of the toe-berm. Although OSPW flow was eventually attenuated at a point a few km downstream of the toe-berm by dilution with uncontaminated groundwater, OSPW apparently bypassed the seepage collection ditch and migrated through the shallow sand aquifer over a few hundred metres.

Yasuda (2006) studied the Albian Sands Muskeg River Mine, where a dyke made of permeable tailings sand has been emplaced around the tailings pond. The dyke is equipped with seepage collection ditches that are designed to collect water from drains in the dyke but also to intercept seepage water not collected by the drains and transmit it to the seepage collection pond for recycling. Yasuda (2006) investigated the effectiveness of the seepage collection system at the downgradient end of the tailings pond by measuring piezometric levels and sampling groundwater in a network of 21 piezometers. Interpretation of both groundwater levels and chemistry data indicated that OSPW had not migrated past the outer ditch, because of higher hydraulic heads that prevail beyond the outer ditch. Yasuda (2006) concluded that, at the time of the study, the collection ditch system was effective for preventing off-site migration of OSPW.

Environmental Defence (2008) reports that for 2007, OSPW from all current tailings ponds is leaking at a combined rate of 11 million L/day (11,000 m^3/d). That value was estimated from seepage rates provided by some operators in their EIAs. When these seepage rates estimates were not available for a given mine, an “average” seepage value was calculated based on the amounts of bitumen produced. Environmental Defence (2008) acknowledges that this average is a crude estimate because it does not account for physical processes responsible for seepage. They acknowledge overall quantitative

limitations of the approach in their technical appendix, but justify using it because they could not get measured seepage rates that should be reported to AENV in annual environmental reports required by the respective EPEA approvals.

In one example, Environmental Defence (2008) report seepage rates mentioned in the Kearl Oil Sands Project Environmental Impact Assessment (Imperial Oil Resources 2005, volume 2, section 5, Table 5-4). Those rates are labelled as “Seepage to Overburden Sands at ETA” and are assumed by Environmental Defence (2008) to escape the mine site. Closer inspection of the Environmental Impact Assessment (Imperial Oil Resources 2005) shows that mitigation measures are proposed. Imperial Oil Resources (2005) indicate that seepage collection wells are to be installed to pump and intercept groundwater affected by seepage from ponds (volume 1, section 7, topic 8). The pumped water is to be returned to the ponds. Imperial Oil Resources (2005) planned to install monitoring wells downgradient of the collection wells to monitor groundwater quality. The actual seepage of tailings water into groundwater is not known, but should be less than values used by Environmental Defence (2008) assuming that the proposed mitigation measures are in place.

For its Joslyn North Mine Project, Total E&P Joslyn Ltd. (2010) recently compiled seepage flow values reported in EIAs for all existing, approved, and planned developments to compute the total seepage to the Athabasca River. They calculate that the total OSPW seepage into the Athabasca River will be 0.146 m^3/s in 2013 and 0.277 m^3/s in 2044, the end year of their project (Appendix J, Table J1-3 of Total E&P Joslyn Ltd., 2010). These values are equivalent to 12.6 million L/day and 23.9 million L/day, respectively. In comparison, Environmental Defence (2008) predicts that OSPW seepage rates will increase from 11 million L/day to 72.2 million L/day from 2007 to 2012, which is greater than values predicted by Total E&P Joslyn Ltd. (2010) for 2012. In neither case is it clear to what extent reduction of seepage flow by seepage collection has been accounted for.

A review of seepage rates presented by Environmental Defence (2008) would be warranted to ensure that mitigation measures are accounted for. Notably, the issue of seepage of OSPW, and discrepancies in predictions from various sources, could be clarified considerably if results from annual environmental assessment reporting under EPEA approvals were made publicly available.

As a result of the extraction and water recycling activities in the surface mine operations, the resulting OSPW will have elevated levels of naphthenic acids (NA) and inorganic ions (e.g. Na^+, Cl^-, SO_4^{2-}, and HCO_3^-) relative to surface waters in the region (MacKinnon and Boerger 1986; Schramm et al. 2000). The unrecovered bitumen in the OSPW is composed primarily of saturated and polar hydrocarbons, with a minor fraction being polycylic aromatic hydrocarbons (PAHs), present predominately as the alkylated series of the PAHs. These petrogenic PAHs are natural constituents of bitumen that have very low solubility into the OSPW (Madill et al. 2001). The tailings pond water also contains NA, asphaltenes, benzene, phenols, cresols, humic and fulvic acids, phthalates, PAH, toluene and metals including lead, mercury, arsenic, nickel, vanadium, chromium, and selenium (see Allen 2008a). Hydrocarbons, VOC, and TRS are emitted as a result of volatilization of residual amounts of naphtha diluent and bitumen contained in the tailings discharged to tailings ponds (Worley Parsons 2009). These are discussed in Section 7.1.6. A summary of the water chemistry of OSPW, the Athabasca River, and surrounding regional lakes is provided in Tables 8.4 and 8.5 (Allen 2008a).

Table 8.4 Summary of various inorganic chemistry water quality parameters for oil sands process waters, the Athabasca River, and regional lakes

Variable (mg/L unless otherwise noted	**Syncrude MLSB (2003)[a]**	**Syncrude demonstration ponds (1997)[b]**	**Suncor TPW (2000)[c]**	**Suncor CT release water (1996-97)[d]**	**Suncor CT pond seepage (1996-97)[d]**	**Athabasca River (2001) [e]**	**Regional Lakes (2001)[e]**
TDS	2221	400–1792	1887	1551	1164	170	80–190
Cond ($uS.cm^{-1}$)	2400	486–2283	1113–1160	1700	1130	280	70–226
Sodium	659	99–608	520	363	254	16	<1–10
Chloride	540	40–258	80	52	18	6	<1–2
Sulphate	218	7–513	290	564	50	22	1–6

[a] MacKinnon 2004
[b] Siwak et al 2000
[c] Kasperski 2001
[d] Farrell et al 2004
[e] Golder and Associates Limited 2002

Source: Allen 2008a

Table 8.5 Summary of various organic chemistry water quality parameters for oil sands process waters, the Athabasca River and regional lakes

Variable (mg/L)	**Syncrude MLSB (1985-1998)**	**Syncrude demonstration ponds (1996-97)[a]**	**Suncor tailings ponds (1982-98)**	**Athabasca River (2001) [b]**	**Regional Lakes (2001)[b]**
DOC	58[c]	26–58	62–67[c]	7	14–27
BOD	25[d]	-	<10–7	<2	-
COD	350[d]	-	86–505[e] 260–973[f]	40d	-
NA	49[f]	3-59	68[g]	<1	1–2
Cyanide	0.5[d]	-	0.01–0.04[e]	0.004[d]	-

[a] Siwak et al 2000
[b] Golder and Associates Limited 2002
[c] Mackinnon and Sethi, 1993
[d] MacKinnon and Boerger, 1986
[e] Gulley 1992
[f] Nix 1983
[g] Holowenko et al. 2002

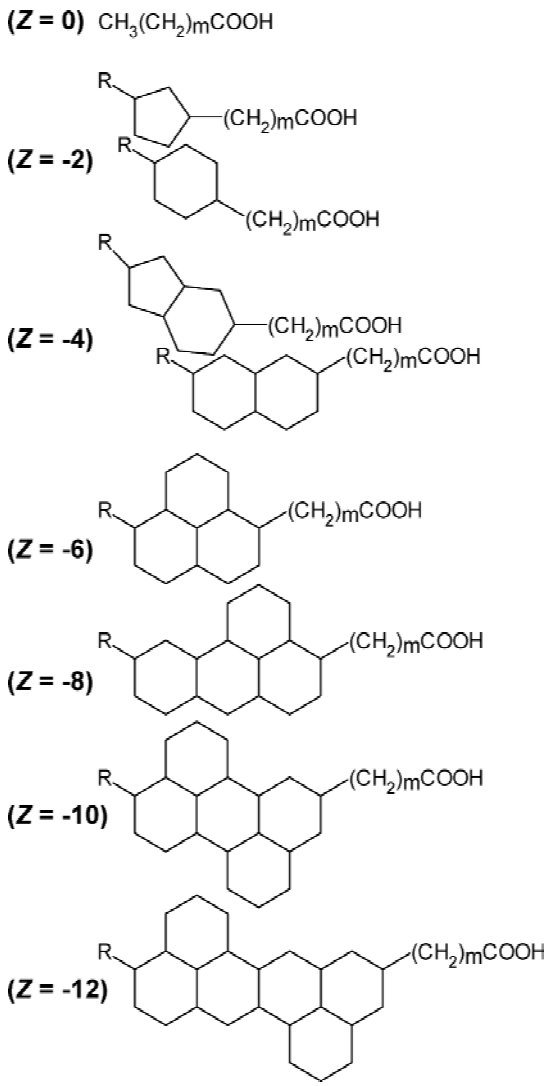
Source: Allen 2008a

NA which are a major constituent of bitumen, are considered to be the primary hydrocarbons in OSPW (Dokholyan and Magomedov 1983; MacKinnon and Boerger 1986; Holowenko et al. 2002). Among the contaminants present in the OSPW, NA are of particular concern because of their apparent toxicity to aquatic organisms Characterization of NA poses a greater technical challenge than is commonly recognized. There is no absolute, all-inclusive scientific definition of NA because they were first named to describe a broad, complex and uncharacterized class of water-soluble acids found in petroleum which were initially most noteworthy because they caused corrosion in refineries and were subsequently found to be a source of fish toxicity (Fan 1991). A 24 h static bioassay sample of tailings pond dyke drainage from the original GCOS plant (now Suncor) was found to show a median lethal concentration (LC_{50}) of about 12% by volume (Hrudey 1975). The bioassay sample contained 77 mg/L of total organic carbon and a preliminary trace organic analysis showed that about one third (by mass) of an ether extract of this sample was a complex mixture of organic acids which is now described as including NA.

Lochte and Littmann (1955) were the first to describe NA as being "*carboxylic acids containing one or more alicyclic rings.*" NA are now generally considered to be a complex mixture of alkyl-substituted acyclic and cycloaliphatic carboxylic acids, which can be described by the general formula $C_nH_{2n}+ZO_2$, where each molecule is assumed to have one carboxyl group, *n* represents the number of carbon atoms in the molecule and *Z* specifies a homologous series (Figure 8.4). *Z* is a negative, even integer related to the number of rings in the molecule of NA, where, for example, $Z = 0$ means no rings, $Z = -2$ means 1 ring, $Z = -4$ means 2 rings, etc. (Fan 1991).

Scott et al. (2008) reviewed the considerable challenges involved in qualitative or quantitative analyses of NA, noting that most of the challenges have yet to be solved given the variety of isomers for each value of *n* and Z, and the inability to separate, then characterize individual NA. The complete, exact chemical make-up of any particular NA sample has yet to be determined. Scott et al. (2008) reviewed several analytical methods developed to estimate the total concentration of NA in a sample and presented results from an adapted GC–MS method with results by analyses by using Fourier Transform Infrared (FT–IR) spectroscopy, an industry standard method (Holowenko et al. 2001; Jivrav et al. 1995). Scott et al. (2008) found that the FT–IR method consistently reported higher concentrations than the more specific GC–MS method: ranging from 1.8 to >20-fold for water samples taken far from oil sands developments, from >26- to >54-fold for water samples from the Athabasca River and regional tributaries in areas of oil sands deposits, and from 0.91 (one SAGD in situ sample only) to 5.7 for OSPW. Clearly, any discussion about NA must be predicated on how NAare measured and what is their source. This situation certainly demonstrates the difficulty with generating a meaningful regulatory standard for a mixture that is so variable, complex, and poorly defined. This situation raises the future prospect of applying more sophisticated analytical techniques to fingerprint various sources of NA which could then be used to track migration of NA in surface water or groundwater.

Figure 8.4 Example NA structures for various z-series. Alkyl groups are represented by **R** and the length of the alkyl chain attached to the carboxylic acid group is represented by **m**.



Source: Frank et al. 2009

Currently the transport mechanisms and persistence of NA in groundwater are still poorly understood (Oiffer et al. 2009). NA are common constituents of oil sands and naturally occurring concentrations of a few mg/L are often observed in surface waters surrounding near-surface oil sands deposits. Ambient concentrations of NA in northern Alberta rivers in the Athabasca Oil Sands regions are generally below 1 mg/L, while concentrations in tailings pond waters can reach over 100 mg/L (Headley and McMartin 2004). Laboratory experiments designed to investigate the fate of NAs indicate that they are not readily degraded and are persistent compounds in the environment. In one such study, Han et al. (2008) show that commercial NA (an NA mixture extracted from petroleum and sold by laboratory chemical suppliers) undergo rapid aerobic microbial biodegradation during laboratory experiments,

while NA from OSPW are much more persistent and degrade at a much slower rate, which is explained by their content of different NA molecular structures.

Most studies on the fate of NA have been conducted in the laboratory and only a few studies have investigated the migration of NA in the field. Gervais (2004) and Gervais and Barker (2005) conducted laboratory and field experiments to evaluate the potential for attenuation of NA in surficial sand aquifers and to identify physical, chemical, or biological processes responsible for their attenuation. Laboratory studies assessed attenuation of NA by sorption and biodegradation, while field studies were conducted in three fluvio-glacial aquifers at the Muskeg River Mine, Suncor's Southwest Aquifer Pond 2/3, and Mildred Lake Settling Basin. The main conclusion from the study was that attenuation of NA in the aquifers results mainly from dilution and dispersion due to groundwater flow movement. Sorption may contribute to attenuation of NA but the dominating sorption process, whether chemical, physical, or electrostatic, could not be determined. Both laboratory and field studies suggest that NA can be degraded aerobically in aquifers, while anaerobic biodegradation does not contribute significantly to attenuation of NA.

Tompkins (2009) conducted tracer tests to investigate the fate of NA at the In Situ Aquifer Test Facility, located on Suncor Energy Inc.'s oil sands mining lease north of Fort McMurray. The tests consisted of injecting process water into the Wood Creek Sand Channel aquifer and monitoring groundwater quality as a contaminant plume developed in the aquifer. The analysis of the tracer test indicated that NA are not attenuated and behave like a conservative tracer in the aquifer. Oiffer et al. (2009) characterized an anaerobic plume of process-affected groundwater in a shallow sand aquifer adjacent to an oil sands tailings impoundment. From field measurements of the chemical composition of the plume, they observed that biodegradation of NA is not significant and that their concentrations are therefore not attenuated in the aquifer. NA are therefore presumed to be persistent in the shallow sand aquifer and their migration is controlled by ambient groundwater flow.

The persistence of NA in groundwater may be advantageous from an environmental management perspective in that well-designed groundwater monitoring systems should be able to detect groundwater contamination problems early and with reasonable certainty. The lack of physical attenuation of NA, presumably because of their water solubility, should cause them to be found at the leading edge of any contaminant plume.

To assess regional cumulative NA loading to the Athabasca River from groundwater seepage, Total E&P Joslyn Ltd. (2010) conducted numerical simulations of NA transport in groundwater, assuming that NA is a conservative species that does not adsorb nor degrade (either of which would reduce loadings to the river). The simulated cumulative total NA loadings from all oil sands projects are 841 kg/d and 1226 kg/day at closure of the Joslyn Mine project (2044) and in the far future (2144), respectively. To transform these loadings into concentrations, Total E&P Joslyn Ltd. (2010) used flow records for the Athabasca River between 1957 and 2004 to compute a 10-year, 7-day low flow value for March, which is equal to 108 m^3/s compared to the mean annual flow of 644 m^3/s for the same

period. Assuming full mixing in the river[5] and using the 7-day low flow value of 108 m^3/s, the NA loadings correspond to increases in NA concentrations of 0.1 mg/L and 0.14 mg/L for 2044 and 2144, respectively. Currently, no water quality guidelines for NA exist, however, that would allow assessing the water quality impact of these predicted increases.

An ongoing concern is that the constituents in tailings ponds pose an immediate significant risk to fish and wildlife. The tailings ponds can become biological traps for passing or migrating birds that mistake these for natural bodies of water or perceive the oily edges of the ponds to be mud flats. Landing in these areas results in the birds becoming oiled which generally leads to a gruesome death, as occurred with over 1,600 ducks in April 2008 (see Sections 3.2.4 and 5.5.3) and more than 400 additional ducks again in October 2010. Through the preening process, birds will also ingest toxic chemicals and may suffer from longer-term health risks. The Syncrude incidents highlight the critical need for oil sands operators to undertake extensive, thorough and effective measures to keep waterfowl off their tailings ponds. However it is equally clear that additional measures need to be developed to minimize the quantity of floating bitumen present on tailings ponds or to at least isolate floating bitumen to areas where bitumen can be continuously skimmed off while maintaining safer fresh water areas where waterfowl can land safely if practical deterrents prove inadequately effective, as was apparently the case in the October 2010 incidents.

Freshly produced OSPW is acutely toxic to aquatic organisms and NA in their dissociated ionic form are thought to be primarily responsible (Frank et al. 2008; MacKinnon and Boerger 1986; Madill et al. 2001). The acute toxicity of “fresh” OSPW declines over time, likely due to a decrease in the proportion of lower molecular weight NA (Holowenko et al. 2002; MacKinnon and Boerger 1986). The natural biodegradation of NA in OSPW is slow and yields an increasing proportion of mono-, di- and tri-hyroxylated NA (Han et al. 2009).

Numerous studies have assessed the effects of OSPW exposure on fish. Initial studies suggested that there were no major effects of OSPW on growth of larval fathead minnow (*Pimephales promelas*), a species native to the area (Sivak et al. 2000). Farrell et al. (2004) exposed fathead minnows to dyke seepage water collected at various locations, OSPW taken from tailings ponds, or water from two reference wetlands not affected by OSPW. At the reference wetland sites, all fish survived 28 days with unchanged hematocrit, leucocrit, and gill histology, whereas the majority of fish exposed to OSPW or dyke seepage water showed signs of stress or had died within 96 hours of exposure. Peters et al. (2007) demonstrated that fresh OSPW can cause deformities in embryos from yellow perch (*Perca flavescens*) and Japanese medaka (*Oryzias latipes*). Histopathological changes in gill and liver tissue have been reported in several fish species exposed to aged OSPW (Nero et al. 2006a,b; van den Heuvel et al. 1999). Yellow perch exposed to oil sands mining-associated water had severe fin erosion and virally-induced tumors within 3–10 months (van den Heuvel et al. 2000).

Increases in liver size and hepatic mixed-function oxygenase (MFO) activity have been observed in fish exposed to oil sands constituents (Nero et al. 2006a; van den Heuvel et al. 1999). These

[5] This complete mixing assumption is not conservative for estimating peak river concentrations of a bank discharge because such transverse mixing will actually not occur for many tens of km downstream. The result is that peak river NA concentrations are likely to be higher than the estimate provided in the river cross sections closer to the banks.

constituents may also have an adverse effect on the reproductive physiology of fish. In vitro studies on gonadal tissues demonstrated reduced production of sex steroids (basal and forskolin-stimulated) in slimy sculpin (*Cottus cognatus*) collected within the oil sands area relative to fish from a reference site (Tetreault et al. 2003). Goldfish (*Carassius auratus*) held in ponds containing aged OSPW had lower plasma steroid levels than reference fish (Lister et al. 2008). Two separate tests with aged OSPW (>15 years) from the experimental ponds at Syncrude Canada showed that water containing high concentrations of NA (>25 mg/L) and conductivity (>2000 µS/cm) completely inhibited spawning of fathead minnows and reduced male secondary sexual characteristics (Kananagh et al. 2010). Collectively these studies have shown that fish are negatively affected by exposure to OSPW. Based on these findings, release of untreated OSPW to the local aquatic ecosystem is not acceptable, as reflected by the regulatory intent of current OSPW containment policy.

Pollet and Bendall-Young (2000) examined the effects of OSPW on survival, growth, rate of development, and frequency of physical deformities in the northern Canadian toad (*Bufo boreas*) and the wood frog (*Rana sylvatica*). *B. boreas* held in OSPW displayed significantly reduced growth and prolonged developmental time (days to metamorphosis) compared to those held in reference waters. As for *R. sylvatica*, two of the three populations tested responded similarly and demonstrated decreased survival and significantly reduced rates of growth when held in OSPW compared to reference waters; the third population displayed no growth and extremely poor survival in all exposures. Collectively these studies suggest that wetlands formed with substantial proportions of untreated OSPW may not support viable amphibian populations.

8.2.2.2 Wet Landscape Option

The wet landscape reclamation option has been proposed to deal with large amounts of MFT and residual OSPW that result from oil sands mining and processing activities (Clearwater Environmental Consultants, 2007 a, b). This will involve human-made water bodies termed end pit lakes (EPLs) constructed in mined-out pits of an excavated area. These will contain oil sands by-products (soft tailings, OSPW, overburden, and/or lean oil sands) placed at the bottom of the pit which will then be capped with surface and groundwater from surrounding reclaimed and undisturbed landscapes. EPLs will be permanent features in the final reclaimed landscape, which is expected to develop into a biologically active community with the ability to support a viable ecosystem and ultimately be capable of discharging water of acceptable quality to the downstream environment. Approximately 27 EPLs have been planned to date within the Athabasca oil sands area (Clearwater Environmental Consultants 2007a); the total area of tailings ponds is already 130 km^2 (ERCB 2009b). Some of the lakes may be more than 50 m deep, more than 10 km^2 in area and contain more than 400 million m^3 in volume. Some of the EPL will take more than 20 years to complete the addition of the tailings and the pumping of water from the Athabasca River (CEMA 2007). The toxicity of the surface waters in these EPLs is expected to diminish over time owing to natural microbial process, leading to the development of stable and viable lake habitats with a biological capability similar to natural lakes in the region. To establish functional biological communities, some EPLs may be stocked with biota, including local vegetation and regionally important fish species. Ultimately the intention is that the EPLs will connect with the regional aquatic ecosystem and thereby discharge into the environment.

There are ongoing concerns regarding the viability of this approach given that EPLs represent an unproven concept (Clearwater Environmental Consultants 2007b). Concerns have been raised regarding the environmental processes (physical, chemical, and biological) that will occur when establishing EPLs (Table 8.6; Clearwater Environmental Consultants 2007a, b). Physical concerns pertain to design, amounts and inflow/outflow rates of reclamation and natural waters, oxygen content, gas formation, and the amount of time water spends within the EPL. Chemical processes that are of concern relate to water quality, water column mixing, and the toxicity and/or concentrations of compounds. Biological issues include potential threats to aquatic life, the bioaccumulation of compounds within the food web, and the development and sustainability of the ecosystem.

Table 8.6 Summary of key end pit lake issues

	Specific Issue or Concern
Physical Issues	• EPL design (depth, surface area, etc.) • Volumes and depths of OSPW • Volumes and depths of soft tailings • Oxygen content • Residence time • Shoreline erosion • Pore water release from soft tailings • Self-sustaining water balance (volumes and rates of inflows and outflows)
Chemical Issues	• Toxicity of soft tailings • Toxicity of water • Toxicity of sediments • Salinity • Bioremediation (decay rates of toxic compounds) • Meromixis (water column mixing/stratification)
Biological Issues	• Extent and stability of littoral zone • Ecosystem development and sustainability • Biodiversity (number of species) • Productivity (population growth rates) • Ecosystem and population level risks • Bioaccumulation of toxic substances within the food web • Productive capability
Sociological Issues	• Aboriginal use • Access • Fish tainting • Recreational use • Safety

Source: Clearwater Environmental Consultants, 2007

If the wet landscape reclamation option is to succeed it will be necessary for EPLs to function as self sustaining ecosystems. Water quality will be a critical issue in determining the success of this approach. The expectation is that soft tailings that are added to EPLs will consolidate over time and

settle to the bottom of the lake. It is presumed that over time, dead organic material from the lake will settle to the bottom and contribute to development of natural bottom sediments on top of the soft tailings. As the settling process could take many years, various coagulants such as gypsum and other chemicals and thickeners will be used to consolidate the tailings at a faster rate and release pore water to the overlying cap water (Guo et al. 2004). At issue is that the pore water will contribute process-related chemicals that will affect the quality of the cap water. Factors of concern include elevated sodium, chloride, and sulphate concentrations, elevated total dissolved solids and conductivity, high pH, reduced dissolved oxygen concentrations, elevated organics and hydrocarbons, all of which will determine the timing and ability of aquatic populations to establish (Clearwater Environmental Consultants 2007a). For example, elevated salinity is due to high concentrations of sodium, chloride and sulphate. Sodium is added as part of the bitumen extraction process, chloride and sulphate are extracted from the oil sands and these all end up in the OSPW. Sodium concentrations in OSPW can be 60 to 80 mg/L higher than natural surface waters (MacKinnon 2004). The high salt concentrations in turn affect the conductivity of OSPW which will range from about 1,000 to 1,500 μS/cm, in contrast to natural waters, which generally range from 100 to 500 μS/cm (van Meer 2004). EPLs will likely have elevated pH (8.1–8.5) which while not toxic on its own can affect the mobility and toxicity of metals and ammonia. For example, under slightly alkaline pH conditions, metals and metalloids that form oxyanions (e.g. V, As, Se, Mo) exhibit increased mobility and may be come more biaovaiable to biota (Dreesen et al. 1982; DeGraff, 2007). The elevated salt concentrations may be problematic in a number of ways. Chloride and sulfate can complex metals, increasing the total concentration of metals in solution, which can promote the transport of these metals in groundwater. Sulfate has a role as a terminal electron acceptor, and when combined with organic matter, can promote bacterial sulfate reduction reactions. The reactions may produce H_2S which can escape, or bind metals through metal sulfide precipitation. The reducing conditions induced from residual organic matter may in turn affect NA degradation (Clemente and Fedoruk, 2005). Collectively the interplay between the the various constuituents in EPLs and how this will affect both the chemical composition and biota are poorly understood and may not be easily predicted.

The Cumulative Environmental Management Association (CEMA) (2007) suggests that when EPLs begin to release water to the surrounding environment their constituents will be non-toxic. Predicted concentrations of many constituents in some of the EPLs will be above those in natural water bodies in the oil sands region for a considerable time. Allen (2008a) provided a useful summary of the target contaminants found in OSPW as typically found in tailings ponds (Table 8.7). When concentrations of these contaminants are compared to environmental water quality benchmarks for the protection of aquatic life it becomes apparent that the degree of bioremediation required is significant. As examples, the reductions in the constituents required to achieve guideline levels are 64–93% for ammonia, 70% for chloride, 90–99% for NA, and >99% for PAHs and other aromatic hydrocarbons (Allen 2008a). The extent to which these levels of degradation will be achieved will depend in large part of whether the final conditions in the EPLs are aerobic or anaerobic. For example, NA is effectively metabolized by microbes under aerobic conditions and is more persistent under anaerobic conditions (Clemente et al. 2004; Han et al. 2009). In any event, it has been predicted that acute and chronic toxicity of some of the EPLs will remain high until at least 2070 (CEMA 2007).

Table 8.7 Summary of target contaminants in OSPW from tailings ponds

Target Chemical	**Typical Concentration Range in Tailings Pond (mg/L)**	**Potential Concerns**
Ammonia	~3–14 [a]	Exceedance of USEPA and CCME surface water quality guidelines, EPEA discharge limits; increased corrosivity of process water
Aromatic hydrocarbons (BTEX, phenols, PAHs)	0.01–5	Historical exceedances of CCME surface water quality guidelines chronic toxicity in reclaimed environments
Bitumen	25–7500	Exceedance of USEPA discharge limit; fouling of extraction facilities
Chloride	80–720 [a]	Exceedance of USEPA surface water quality guideline and EPEA discharge limit; increased corrosivity of process water
Hardness	70–112[a]	Scaling of extraction facilities; disruption of bitumen extraction chemistry
NA	50–70	Primary source of acute toxicity to aquatic biota
Sulphate	230–290 [a]	Exceedance of USEPA surface water quality guideline; increased corrosivity of process water
Suspended solids	variable with depth; <1% in surface water	Disruption of extraction process; fine clay particles form non-settling sludge that traps process water producing large volumes of tailings
Total dissolved solids	1900–2200	Osmotic stress to plants in reclaimed landscapes, chronic toxicity and community effects on aquatic biota; increased corrosivity of process water
Trace Metals (Cr, Cu, Pb, Ni, Zn)	~0.0001–3	Historical exceedances of CCME and USEPA surface water quality guidelines

Note: USEPA, Surface Water Quality Guidelines for the Protection of Aquatic Life (USEPA 1999); CCME, Surface Water Quality Guidelines for the Protection of Aquatic Life (CCME 2005), EPEA, AENV Industrial discharge limits for various industries (AENV 1999); process water quality data are from Syncrude Canada Ltd and Suncor Energy Corp tailings ponds circa 1982–2003. (Nix 1983; MacKinnon and Benson 1985; Gulley and MacKinnon 1993; Siwik et al. 2000; Kasperski 2001; MacKinnon 2004)

Source: Allen 2008a

NA are considered to be the primary contributor to toxicity in EPL (Howelenko et al. 2002; Frank et al. 2008a). NA concentrations could be up to 60–120 mg/L, considerably higher than the non-toxic concentrations of < 1 to 4 mg/L detected naturally in surface waters in the Athabasca oil sands region (Holowenko et al. 2001; Golder 2006b). The high concentrations of NA in EPLs would in the short term be acutely toxic to aquatic organisms, including algae, bacteria, plankton and fish (MacKinnon 2004; Clemenete and Fedorak 2005; Frank et al. 2009). Over relatively short times (6-12 months) of ageing under natural conditions, OSPW loses its acute toxic response and this improvement has been attributed to the biodegradation of NA, particularly the lower molecular weight NA (MacKinnon and Boerger 1986). Han et al. (2009) have shown that over time the NA associated with fresh OSPW become reduced in aged OSPW sites but the amount of hydroxylated NA increased. At this time, the chronic toxicity of hydroxylated NA is poorly understood. In studies conducted in tailing ponds, it has

been shown that aged OSPW (>15 years under natural conditions), are not acutely toxic to either adult or larval fathead minnows. Nevertheless a wide range of effects on growth, reproduction, and development in fish continue to persist (see above).

While previous studies have shown that OSPW NA can be partially removed through aerobic microbial degradation under laboratory conditions (Herman et al. 1993; Scott et al. 2005; Han et al. 2009), the extent of NA degraded in the field is less. The disappearance half-lives for NA in OSPW are 12.8–13.6 years (Han et al. 2009) suggesting that these compounds will continue to be a concern for an extended period of time. Most groundwater plumes are expected to be anaerobic, which will lead to greater persistence of NA in groundwater (Oiffer et al. 2009).

There is concern that PAH in EPLs may present a significant hazard for tumorigenesis, endocrine disruption, and behavioural and growth effects. Numerous studies have demonstrated a cause-and-effect relationship between neoplastic and neoplasia-related lesions in fish exposed to PAHs in sediments (Myers et al. 1991, 2003). Both yellow perch and goldfish caged for three weeks in tailings ponds containing aged OSPW induced marked changes in gill and liver morphology (Nero et al. 2006a, b). Yellow perch had significantly higher proliferative alterations while goldfish had higher degenerative and inflammatory alterations in gill morphology. It is not clear whether these effects can be attributed to PAHs or other constituents within OSPW.

There continues to be concern that elevated salinity in EPLs can act as a stressor by increasing the toxicity of other compounds, including NA (Quagraine et al. 2005). Sodium and sodium bicarbonate concentrations may induce acute and chronic effects in zooplankton (Harmon et al. 2003), osmotic stress in plants (Crowe et al. 2001), and shifts in phytoplankton community structure (Leung et al. 2003).

The anticipated residence times for waters in planned EPLs range from about 1 year to 100 years, with a median residence time of about 20 years before the contents would be discharged to the environment. However, water quality criteria for discharged EPL waters have not been established yet (Clearwater Environmental Consultants 2007a).

While modeling studies and industrial proponents suggest that development and operation of EPLs pose a low risk to the environment (Clearwater Environmental Consultants 2007b), there is much uncertainty. Some of this relates to the long term storage that is required as full densification of the fine tails could take many centuries and the integrity of containment structures remains a concern. There continues to be much uncertainty related to issues of salinity, retention time, ground water recharge and discharge rates, EPL limnology, and the chronic toxicity of OSPW and its constituents. One way to improve EPL water quality may be to reduce initial loading rates and this could involve advanced treatment of the waste streams. However even if these issues are better understood, there are long term natural disturbances such as extreme weather, flooding and ice formation that could affect the function and success of EPLs. Collectively, the level of uncertainty is high and the ERCB noted in its frequently asked questions briefing for the new Tailings Pond Directive (ERCB 2009a) that the first EPL was approved in concept in 1993 subject to demonstrated success, yet 17 years later, the EPL concept has yet to be demonstrated. For a strategy which is being so widely pursued by oil sands operators,

financial security for dealing with MFT and OSPW in site reclamation is a major concern. This concern is discussed in more detail in Section 11.3.3.

Given the ongoing concerns regarding the toxicity of constituents within EPLs, it is not surprising that technologies associated with municipal and industrial waste water treatment have been considered for OSPW. Conventional wastewater technologies that are applicable to the oil sands industry are reviewed by Allen (2006 a, b) and by Worley Parsons (2009). These include primary, secondary, and tertiary treatment processes. Primary treatment involves physical processes such as sedimentation, flotation, filtration, and aeration. Secondary treatment processes refer to biological treatment, methods involving microorganisms to stabilize wastewater water through the removal of nutrients and organic compounds. Biological treatment technologies include aerated lagoons, activated sludge, and fixed-film bioreactors. These processes are designed to reduce biochemical oxygen demand (BOD) but do not effectively remove dissolved inorganic species and recalcitrant organic compounds. Tertiary treatment, referred to as advanced treatment, encompasses a wide range of processes that target dissolved and particulate species that are not effectively removed by primary and secondary methods. Advanced treatment technologies available include chemical precipitation, advanced oxidation, membranes, ion exchange, adsorption, and treatment wetlands. Chemical oxidation is generally considered the most efficient technology for decreasing contaminant concentrations and was rated highly for its ability to degrade pollutants. However, when energy requirements were considered, chemical oxidation ranked poorly relative to activated carbon and biological oxidation for treatment. Although both of these methods reduced concentrations of target pollutants, they also resulted in the production of solid waste. These evaluations have been done at a theoretical level and no serious progress will occur until at least laboratory-scale research is pursued with more promising technologies to gain some meaningful idea of feasibility.

The performance of wetlands for treating OSPW is discussed in Section 9.4.6. In particular, the study by Bishay (1998) showed some promise for removal of ammonia and hydrocarbons.

The feasibility of using advanced water treatment technologies for the removal of the toxicity of OSPW was illustrated in a recent study (Scott et al. 2008). Ozonation of OSPW decreased NA concentrations and resulted in an effluent that is effectively non-toxic in the acute Microtox microbial toxicity assay. The OSPW before and after ozonation was tested for effects on steroid hormone biosynthesis by H295R cells in tissue culture. These studies also showed that OSPW decreased testosterone production and increased production of estradiol over a 48-hr period and that ozonation diminished the impacts of OSPW on steroidogenesis (He et al. 2010).

8.3 In Situ Bitumen Recovery

In situ mining is conducted in areas where the oil sands deposits are at depths greater than 150 m (Section 4.4). In contrast to surface mining, there is no material excavation required and bitumen is recovered by injecting steam in wells. The main process now used is SAGD. Groundwater (saline in one case) is used to generate the steam, with about 90% to 95% of the water used to generate steam being recycled. To produce 1 m^3 of bitumen, about 0.5 m^3 of groundwater is required (Section 4.4).

8.3.1 Water Quantity

The primary water quantity issue for in situ mining concerns groundwater because it is the source of water used. Groundwater must be pumped from wells located in permeable geological formation close to the in situ production site. Pumping of groundwater reduces hydraulic heads (or equivalently, groundwater energy) in the subsurface, which can modify groundwater flow patterns because groundwater flows in the direction of decreasing hydraulic head (level of energy).

The Water Conservation and Allocation Guideline for Oilfield Injection (AENV 2006a) sets limits on the volume of water that can be extracted. The guideline limits the proposed use for oilfield injection of non-saline groundwater, which is groundwater with less than 4,000 mg/L of total dissolved solids. The volume of water extracted will be restricted to a maximum of one-half of the long-term yield of a given aquifer in the immediate vicinity of the water source well. The guideline mentions that this objective will be met by limiting drawdown in the production aquifer to 35% during the first year of operation and no more than 50% over the life of the project. The drawdown, which is the decrease in water level with respect to the initial level prior to pumping, is measured in an observation well typically located a distance of 150 m from the production well. The percentage mentioned above is calculated by dividing the simulated drawdown by the available hydraulic head in the observation well. The available hydraulic head is usually assumed to be the observed hydraulic head in the well without any groundwater extraction.

An example of the use of the guideline is given in the MacKay River in situ application (Athabasca Oil Sands Corp. 2009). In the application, simulated reductions in water levels as a result of non-saline groundwater withdrawal were interpreted in terms of percent change in available hydraulic head according to the following categories:

- negligible (<5% — may be within the range of natural variability and not detectable).
- low (5–15% — may be detectable but within AENV guidelines for non-saline use).
- moderate (15– 50% — detectable but within AENV guidelines for nonsaline use).
- high (>50% — exceeds AENV guidelines for non-saline use, if at a distance greater than or equal to 150 m from a source well)

Once operations start, monitoring is required to ensure that the foregoing objectives are met.

Individual applications include a groundwater flow modelling section to predict the impact of groundwater withdrawal on water levels. The models are local in scale and can only be used in the vicinity of the in situ operations. Since there is currently no conceptual hydrogeological model for the entire oil sands region, the amount of groundwater available for bitumen extraction is unknown and consequently the quantitative impact of extraction on regional groundwater reserves remains unknown.

The Alberta Geological Survey has conducted several studies to provide a better understanding of the geology and hydrogeology for the in situ oil sands region. Examples are the hydrogeological study of Cold Lake by Hitchon et al. (1985) and regional studies of the hydrogeology of bedrock units by

Bachu and Underschultz (1993) and Bachu et al. (1993). Bachu and Underschultz (1993) identified three hydrostratigraphic units within the Mannville Group in northeastern Alberta. These are the McMurray–Wabiskaw aquifer/aquitard system at the base of the succession, the Clearwater aquitard, and the Grand Rapids aquifer at the top.

The groundwater flow dynamics of the Mannville Group in the east-central Athabasca area has been investigated by Barson et al. (2001). Within the Mannville Group, they identify four aquifers separated by three intervening aquitards. The four aquifers are, from the base up, the basal McMurray, upper McMurrayWabiskaw, Clearwater and Grand Rapids sandstones. The intervening aquitards are the bitumen-saturated middle McMurray and the Wabiskaw and Clearwater shales. Regional groundwater flow in the Mannville Formation is driven by local topography, with groundwater recharge at the highlands in the southeast and at the Stony Mountain upland, and discharge to surface water along the valleys of the Athabasca, Clearwater,and Christina rivers. From their description of the regional groundwater flow dynamics in the Mannville Group, Barson et al. (2001) identify several hydrogeological issues related to in situ operations that need further studies for better understanding of local flow dynamics. Issues identified relate to the sustainable use of large volumes of water needed for steam production, the safe disposal of wastewater, the protection of groundwater resources from overuse and contamination, and the need to avoid large-scale cross-formational flow.

Related to the last issue, Barson et al. (2001) indicate that oil sands have high absolute permeability, in the range of 10^{-13} to 10^{-12} m^2, but very low relative permeability to water when saturated with bitumen. They therefore act as low-permeability aquitards when saturated with bitumen, and effectively restrict vertical groundwater flow between underlying and overlying aquifers. In situ processes recover about 50% of the total volume initially present (Section 4.3). In situ recovery of bitumen with SAGD might therefore increase the relative permeability of the oil sands and create a hydraulic connection between the basal McMurray and upper McMurray aquifers through abandoned middle McMurray steam chambers. The hydraulic connection can be prevented by keeping a sufficiently thick base layer of bitumen sand undeveloped that would maintain the aquitard property of the oil sands (Barson et al. 2001). This option would conflict with the ERCB conservation mandate to maximize recovery of the bitumen resource so the ERCB faces a difficult choice in pursuing this approach to assuring the hydraulic integrity of the aquitard.

Between 1999 and 2001, the Alberta Geological Survey conducted groundwater studies in the Athabasca Oil Sands (in situ) area of Alberta within a program jointly funded by the Government of Alberta, through the EUB, and by the Government of Canada through the Ministry of Western Economic Diversification under the Western Economic Partnership Agreement. The purpose of this program was to collect groundwater samples from the various aquifers for baseline characterization of groundwater conditions in the area prior to extensive oil sands development.

A series of reports on the work conducted in 1999–2001 present results from the groundwater characterization. In the study of Lemay (2002), nine piezometers were installed at three sites to investigate the baseline groundwater chemistry in Quaternary drift aquifers, Quaternary-Tertiary buried channel aquifers, and Lower Cretaceous aquifers. A total of 44 samples were taken and analyzed in the field for pH, oxidation-reduction potential, temperature, conductivity, dissolved oxygen, and total

alkalinity. Laboratory analyses were conducted for major, minor, and trace elements, organic compounds, and stable and radiogenic isotopes. Lemay (2002) presents a preliminary analysis of the results.

Lemay (2003) reports results from groundwater sampling in Quaternary drift aquifers and Quaternary-Tertiary buried channel aquifers, with a focus on arsenic in these aquifers. A total of 24 samples were taken and analyzed for the same parameters as described in Lemay (2002), including arsenic. A few samples contained concentrations of naturally occurring arsenic greater than the detection limit used in the laboratory (0.01 mg/L) a level which became the drinking water guideline in 2002.

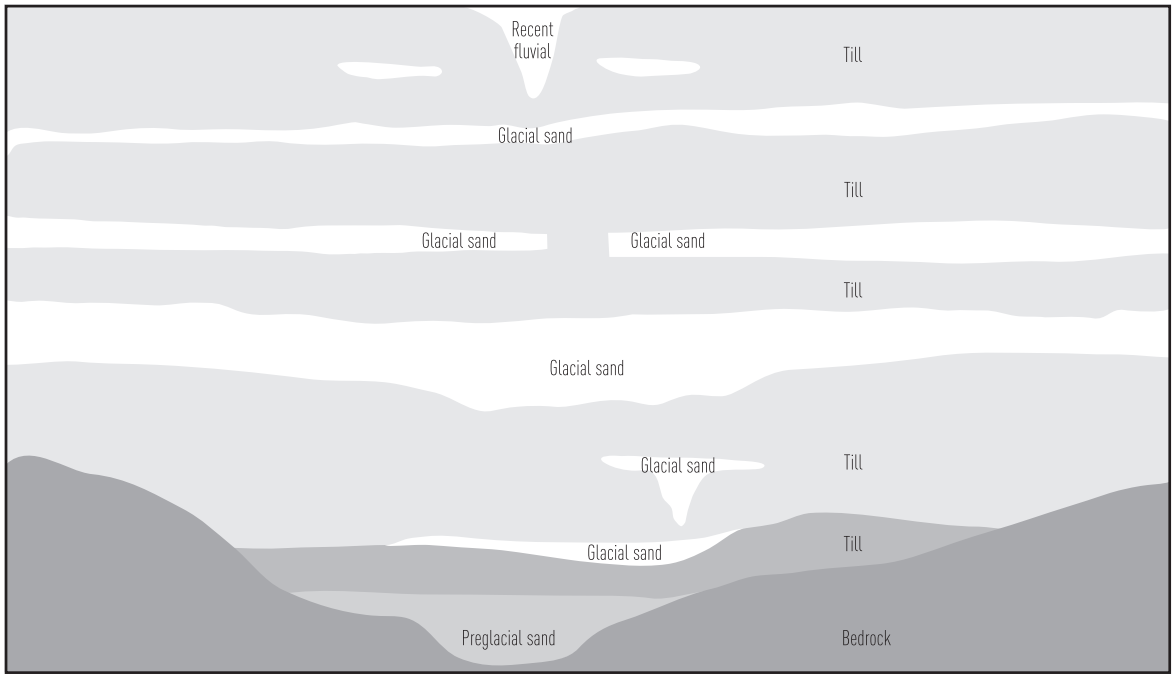
In another study conducted by the Alberta Geological Survey, Parks (2004) indicates that the main source of fresh groundwater for in situ development is a complex regional system of buried pre-glacial and glacial channel aquifers. These aquifers are hydraulically connected to lakes and rivers, and management of groundwater extraction will require co-management with surface water resources. In that context, Parks (2004) mentions that a better understanding of regional-scale groundwater–surface water interactions is required for such management. The use of saline or brackish groundwater for in situ operations produces saline wastewater that requires disposal, most often by underground injection. Knowledge of the hydraulic conductivity of the subsurface is required to assess the underground capacity for saline wastewater injection, as is the degree of connectivity between the injection location and overlying aquifers or rivers (Parks 2004).

Previous regional hydrogeological studies, such as those Hitchon et al. (1985) and Bachu et al. (1993) focused on the bedrock but did not investigate in detail the overlying sediments. To address the lack of data of these sediments, Andriashek (2003) studied the nature and distribution of Late Tertiary and Quaternary (drift) sediments that overlie the Cretaceous bedrock surface above the oil sands deposits, in the region between the Cold Lake area and Fort McMurray. These sediments overlie the underlying Cretaceous bedrock and their thickness can reach 300 m. The maximum thicknesses correspond to the location of buried preglacial channel systems that cut into the bedrock surface, with the Wiau and Christina channels being the most important. Secondary sand and gravel channels from the Late Tertiary are also found above the bedrock. They represent local aquifers that constitute ideal targets for sources of fresh, potable water, except when in contact with oil sands. These sand units, also called subglacial tunnel valleys, are found at numerous locations in the oil sands region (Andriashek and Atkinson 2007). These valleys are cut into the bedrock and are difficult to detect from borehole data because they are narrow and overlain by glacial sediments, which range in composition from low-permeability tills to high-permeability sand units. Figure 8.5 (Andriashek 2003) illustrates the layer-cake model, which is one possible geometrical arrangement of sand and till units in the region. In that model, the sand aquifers are isolated one from another by the low-permeability tills. Andriashek (2003), however, states that glacial deposits do not follow the layer-cake model because of the depositional mode, which was often catastrophic, such as sudden releases of glacial meltwater. The most probable geometrical configuration is the labyrinth, stair-stepped model (Figure 8.6), in which permeable sand units can be in hydraulic connection. The hypothetical geometry illustrated in Figure 8.6 shows that the glacial sand units form a direct vertical pathway between ground surface and bedrock. The tunnel valleys aquifers pose significant constraints for oil sands development

(Andriashek and Atkinson 2007). In the surface mining area, they can act as natural pathways for the subsurface migration of fluids from overlying tailings ponds. This geologic feature is clearly one that must be avoided in the design and approval of tailings ponds. For in situ extraction, expanding steam chambers from injection wells completed close to valley walls can escape through breaches in the cap rock which loses pressure integrity (Section 3.2.3, Figure 8.7; Andriashek 2003).

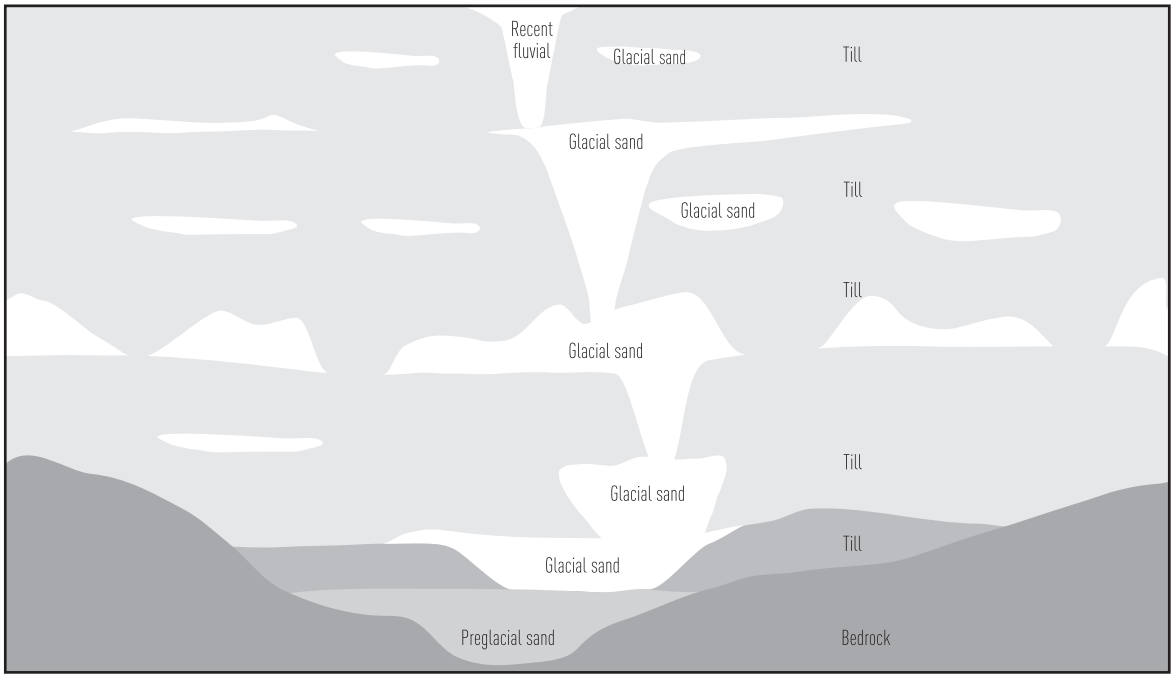
Although surface water is not used for in situ bitumen extraction, the construction of the infrastructure required for in situ projects creates concerns for surface water bodies. The infrastructure includes roads, building, landfills, power lines, and areas where vegetation is cleared to conduct seismic surveys. Concerns relate to the disruption of surface water flows (runoff quantity and peak flow) and drainage patterns, which can in turn lead to modifications in erosion and sediment transport in streams. Codes of practice and guidelines to avoid or minimize such impacts are well established, so the key is to ensure effective compliance and enforcement.

Figure 8.5 Layer-cake hydrostratigraphic model. Coarse, permable aquifer units (sand) are sandwiched beween aquitards (bedrock and till) and are hydraulically isolated



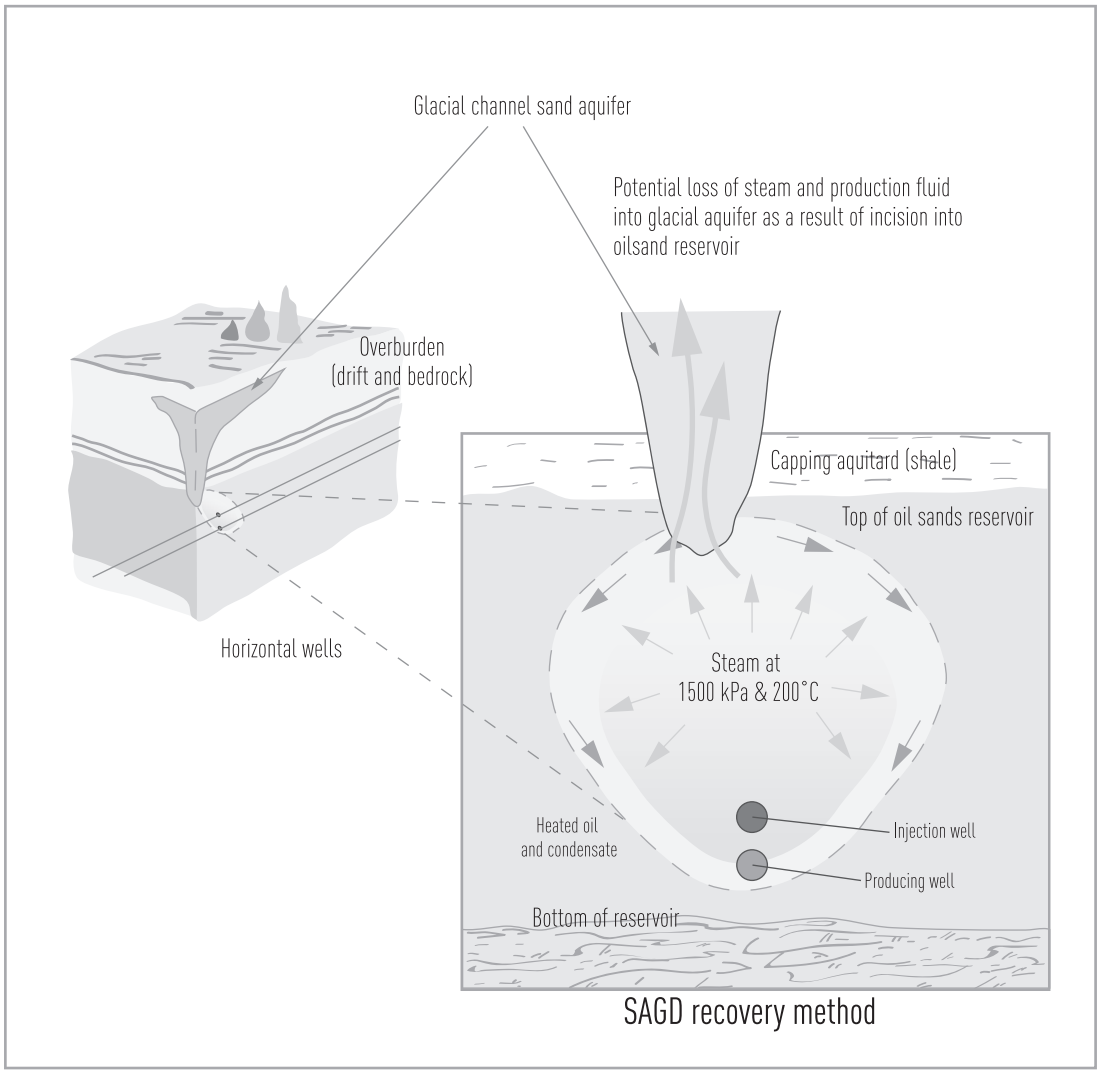
Source: Andriashek 2003

Figure 8.6 Labryinth, stir stepped hydrostratigraphic model. Coarse, permeable units are hydraulically connected as a result of downcutting through aquitards and superposition of younger glaciofluvial deposits.



Source: Andriashek 2003

Figure 8.7 Cartoon diagram of glacial channel incision trough thin overburden above SAGD operation



Source: Andriashek 2003

8.3.2 Quality Issues

Because in situ mining involves groundwater extraction and steam injection in the subsurface, the primary water quality issues are related to the potential degradation of groundwater. A lack of information on the regional hydrogeology of the oil sands region makes it difficult to evaluate how groundwater extraction modifies the regional groundwater flow dynamics and the groundwater composition. As stated previously, modified groundwater flow dynamics could lead to mixing of freshwater and saltwater. Saltwater intrusion into a freshwater aquifer would negatively impact its quality and could make the water unsuitable for consumption and other freshwater uses. Another potential issue to consider when designing monitoring program is that dewatering can promote entrainment of oxygen into the subsurface, which could in turn cause oxidative release of some toxic elements into groundwater, if those elements are present. One example is arsenic originally present as sulphides.

Andriashek and Pawlowicz (2002) note that, during geological mapping in the oil sands regions, several occurrences of hydrocarbon odours, likely bitumen, were noted for surface sediments. They sampled Quaternary till from both outcrops and drill cores to further investigate the origin of these odours. Their results show that naturally occurring hydrocarbons are regionally extensive within Quaternary sediments, particularly till. Almost all of the observations were of hydrocarbons located south and west of major oils sands deposits, suggesting they occur directly down-glacier of near-surface oil sands deposits. Andriashek and Pawlowicz (2002) state that the naturally-occurring bitumen in till sediment should be better documented to establish baseline values prior to exploitation of the oil sands.

A measure taken to reduce the extraction of good quality groundwater is to extract water from aquifers where salinities exceed the permissible value for drinking water, which is a concentration of 4000 mg/L for total dissolved solids. Saltwater is treated above ground to remove salt before generating steam, and it can also be mixed with fresh groundwater. Removing salts generates wastes that require disposal. One method is the deep injection of waste in the subsurface. The deep-well disposal of process water and waste raises the same concern for subsurface contamination that exists wherever this approach is commonly practiced throughout Alberta for oil field wastes and other related wastes approved by the ERCB (1994).

Another concern that has not been addressed at the scale of the in situ operations is the impact of groundwater extraction, steam injection, and deep-well injection on the interaction between groundwater and surface water. Most operations related to in situ mining are at depth and may not have an immediate impact on surface water bodies, but more detailed hydrogeological studies are required to determine the link between deeper groundwater and surface water in the in situ region. Andriashek and McKenna (2008) indicate that the Government of Alberta will invest in its geological and groundwater mapping to address these issues.

Other concerns that are addressed in environmental impact assessments for in situ mining relate to drilling operations. For example, boreholes that are drilled for use as SAGD wells must be properly cased (isolated) from the production zone to ground surface, to avoid creating a direct and fast pathway between these two locations. There is a possibility of failure of the casing used for SAGD wells, either from failure of the cement seal or fracturing of the caprock, which could create fluid leaks from the well into the surrounding geologic formations. The probability of casing failure is, however, considered to be very low based on extensive experience with oil wells in Alberta.

Groundwater temperatures of aquifers, including shallow surficial aquifers, are expected to increase in the vicinity of operating SAGD wells. Any increase in temperature is expected to result in negative effects because of the potential for enhanced solubility and/or mobility of chemical constituents that are otherwise stable for naturally-occurring temperatures. The presence of elevated concentrations of dissolved salts, especially chloride, will further exacerbate these effects. For environmental impact studies, temperature increases are predicted with numerical models and mitigation measures include locating monitoring wells near SAGD wells to monitor groundwater temperature during operations. The evaluation of the impact of temperature increases is complicated by the lack of guidelines on the maximum change in groundwater temperature allowed. Predictions are made with models that only

consider changes in groundwater temperature and do not account for the possible impact on surface water temperature.

Disruption to the surface flow regime and drainage patterns, mentioned previously, can have an impact in surface water quality, for example, from changes in stream flows and lake levels, which can affect surface water quality, or the release of suspended sediments.

8.4 Downstream Effects

There is considerable interest in defining possible impacts of oil sands development on water quality of the lower Athabasca River and its tributaries notably by the Cumulative Environmental Management Association (CEMA) and by the Regional Aquatics Monitoring Program (RAMP). Concerns relate to both surface and in situ oil sands projects and impacts associated with the accompanying urban and industrial infrastructure. The issues of concern relate to fish and fish habitat, suitability of fish for consumption, municipal, local domestic and industrial water supply, wildlife usage, transboundary obligations, and Wood Buffalo National Park needs (CEMA 2007). Given the size of the watershed in question, the magnitude of the environmental management task is huge.

Evaluating potential impacts of mining operations involves: chemical measurements and biological effects assessment to characterize water quality, using the best available criteria (when they exist) for setting effects-based objectives, and understanding background conditions that are specific to the Lower Athabasca River. Current practice includes applying the Canadian Council of Ministers of the Environment (CCME) water quality guidelines to surface water (CCME 1999). The observed and predicted concentrations of key chemical indicators are compared to either the Surface Water Quality Guidelines for Use in Alberta (AENV 1999), the Canadian Water Quality Guidelines, or relevant United States Environmental Protection Agency Guidelines, based on the recommended procedures described in the document entitled: *Protocol to Develop Alberta Water Quality Guidelines for Protection of Freshwater Aquatic Life* (AEP 1996).

At present there is ongoing monitoring of water quality in rivers, lakes, and the Athabasca River Delta to assess potential exposure of fish and invertebrates to organic and inorganic chemicals. The RAMP program was initiated in 1997 and received initial guidance from the Canada–Alberta–Northwest Territories Northern Rivers Ecosystem Initiative (NREI) which was launched in 1998 (McMaster et al. 2006). Measurement endpoints include: major ions, nutrients including ammonia, total nitrogen, total phosphorus and dissolved organic carbon, general organics including NA and phenolics, total metals (about 20 constituents including aluminum, arsenic, cadmium, selenium, and zinc), PAHs and other consituents including phthalates, acrylamide, petroleum hydrocarbons, vanadium, and dissolved oxygen.

Sublethal toxicity bioassays are conducted using ambient river water from selected stations to assess acute and chronic effects on different aquatic organisms. In the surface mining area, groundwater and surface water can be in contact with naturally-occurring oil sands deposits. Concentrations of contaminants found in the oil sands, such as NA, can be measured in natural waters not impacted by OSPW. A monitoring challenge exists to determine a baseline for these contaminants in natural waters.

In the case of the RAMP, chemical characteristics of water quality measured at each station was summarized into a single index value, ranging from 0 to 100, using an approach based on the CCME Water Quality Index. This index is calculated using comparisons of observed water quality against user-specified benchmark values, such as water quality guidelines or background concentrations. Three factors are considered: the percentage of variables with values that exceed a given user-specified benchmark; the percentage of comparisons of variables that exceed a given user-specified benchmark; and the degree to which observed values exceed user specified benchmark values. Using this approach, water quality scores were classified at each RAMP monitoring station using the following scheme:

- 80 to 100: negligible-low difference from regional baseline conditions;
- 60 to 80: moderate difference from regional baseline conditions; and
- below 60: high difference from regional baseline conditions.

The overall conclusion for the 2009 RAMP study which summarized the assessment of 12 watersheds and about 10 additional sites was that regional water quality data was generally similar for all key water quality measurement endpoints between stations designated as test locations and those selected for baseline monitoring, and that the measured parameters generally fell within the range of historical observations from previous years (RAMP 2009). The overall conclusion is that contaminants found in the Athabasca River and its tributaries have a natural origin (RAMP 2009). Despite these conclusions, a detailed examination of the 2009 RAMP results revealed that there were deviations from the baseline at about 25% of the sites for one or more of the water quality parameters evaluated. These changes included variations in the concentrations of individual ions, nutrients (nitrogen and phosphorus), total dissolved solids and some metals. There were no consistent trends for which selected water constituents were elevated.

These results are in general agreement with many previous studies. As an example, Conly et al. (2007) assessed the concentration of metals in bottom and suspended sediments in three tributaries to the Athabasca River, the Ells River, MacKay River, and Steepbank River. They concluded that measured metal concentrations were within CCME guidelines, except for arsenic whose elevated concentrations were assumed to result from natural background levels rather than anthropogenic sources. As part of the same study, Headley et al. (2005) report on the occurrence of inorganic chemicals in the water of those three tributaries: drinking water guidelines were exceeded at some locations for aluminum, iron, manganese, copper, zinc, silver, and lead, with iron being the most predominant trace metal. However, it was concluded that the high concentrations of metals were of natural origin. Other studies examining river water and sediments over a four-year period confirmed that tributaries passing through the Fort McMurray oil sands region contained significant concentrations of naturally derived hydrocarbons (McMaster et al. 2006). The observed concentrations of hydrocarbons, however, decreased when the tributaries mixed with mainstem rivers, whose flow rates are higher. Sediment concentrations in the mainstem rivers were below 0.01 μg/g, which is typical of pristine areas not affected by oil sands deposits. Sediments in the Athabasca River, its tributaries, downstream deltas, and the western Lake Athabasca indicated the presence of petrogenic PAHs but McMaster et al. (2006), summarizing the findings of the NREI, did not find evidence of impacts from the oil sands operations on hydrocarbon

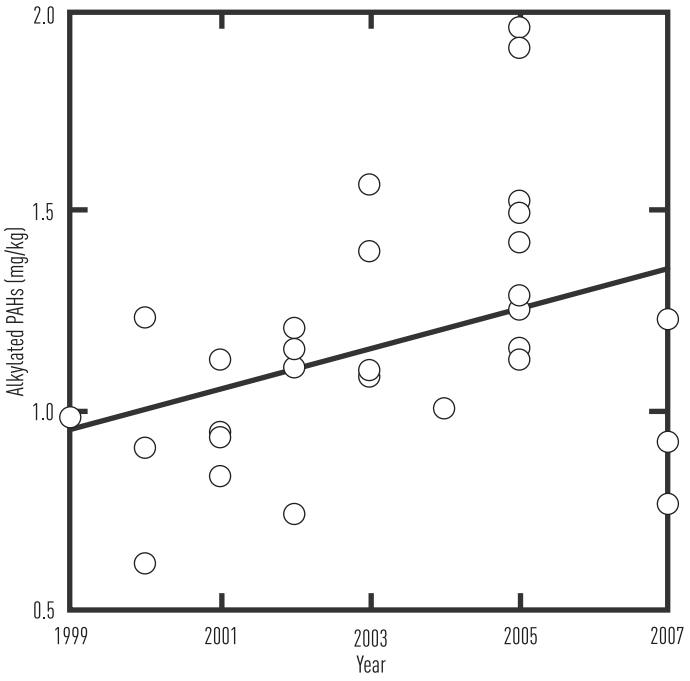
distributions and sediment toxicity. Other studies by Conly et al. (2002) suggest that less than 3% of the sediment-bound hydrocarbon contaminants detected downstream of the oil sands development were attributed to the oil sands mining operations.

Nevertheless, there is controversy over the impact of oil sands operations on river water quality. Timoney and Lee (2009) reported results from a RAMP pilot project deploying semi-permeable membrane devices (SPMDs), which passively collected lipophilic[6] organic materials at both upstream and downstream locations on the Muskeg River in the summer of 2006. Results from this pilot project had been previously reported (Appendix D-1) in the 2006 RAMP Final Technical Report (RAMP 2007). The results for PAH (and other polycyclic aromatic compounds, PAC) analyses were obtained for two out of three sampling sites, with one of the sites invalidated by dropping water levels which left the SPMD exposed to air. PAC include compounds related to PAH, like polycyclic aromatic sulphur heterocyles (PASH), which are not strictly hydrocarbons, but which are commonly found with natural petrogenic sources of PAH. Problems were encountered in the pilot project with the day zero and travel blanks which were contaminated by lower molecular weight hydrocarbons, particularly alkylated naphthalenes and fluorenes and alklylated dibenzothiophenes (PASH). Notwithstanding these problems, the single comparison between a site upstream of oil sands developments and one downstream clearly showed substantially higher (4-fold higher for total detectable PAHs, including PASH, but excluding retene and 3.6-fold higher for the higher molecular weight PAHs) levels at the downstream site. Although this comparison was based on a single pair of samples, Timoney and Lee (2009) applied a statistical analysis (Mann-Whitney test) on "*all PAHs as a group*" to demonstrate statistical significance for the evident upstream–downstream differences.

Timoney and Lee (2009) performed their own analyses of RAMP showing that over the period 1999–2007, concentrations of alkylated PAHs increased in Athabasca River Delta sediment from about 1.0 mg/kg in 1999 to a range from about 0.75 to 1.25 mg/kg in 2007, with values in intervening years ranging from about 0.6 to about 2 mg/kg (Figure 8.8). The Timoney and Lee conclusion about a long term trend in sediment PAH levels is unwarranted given the small overall range of PAH levels detected and the comparatively large variability of PAH values in a given sampling year. More recent data (including 2008 and 2009 results) confirm only the variability, but do not show any clear upward trend for alkylated PAHs in sediments for the Athabasca Delta (RAMP 2010). When data back to 2001 are compared on the basis of being normalized to 1% TOC, to account for variability in organic content of sediment samples, an adjustment that is scientifically sound based on the behaviour of PAHs in water in contact with sediment, there is definitely no upward trend in PAH at any of the four sites in the Athabasca Delta (RAMP 2010). Given the ongoing controversy about downstream contamination, this matter is worthy of continuing analysis and interpretation.

[6] Lipophilic means fat-soluble, corresponding to low water solubility. Lipophilic organic compounds, like medium and higher molecular weight PAHs can bioconcentrate in the fat tissues of aquatic organisms. PAHs do not necessarily bioaccumulate in aquatic food webs because they are efficiently metabolized by aquatic organisms.

Figure 8.8 Hypothesized trends in alkylated PAH concentrations from the Athabasca River Delta sediment. Raw data from RAMP. Some data points overlap; line is a least squares regression.



Source: Timoney and Lee 2009.

In another recent study, Kelly et al. (2009) reported results for flowing water samples in six tributaries to the Athabasca River collected using polyethylene membrane devices (PMDs) which also collect integrated samples for dissolved lipophilic compounds like PAHs in a manner similar to SPMDs (Carls et al. 2004). Kelly et al (2009) reported their results including PASH (mainly alkylated dibenzothiophenes, as was reported in the RAMP study of SPMDs, but Kelly et al. refer to this broader class as polycyclic aromatic compounds [PAC]). The PMD results are obtained as a mass of PAC extracted in the laboratory from the device which collected PACs from flowing waters over the sampling period of about 30 d. These results must be translated into water concentrations according to information on the equilibrium partitioning of each individual PAC between water and lipophilic stage. Thus, the water concentrations between sites should be interpreted in relative site comparisons rather than in absolute concentration terms and should not be directly compared with aquatic water quality criteria concentrations (Carls et al. 2004). Dissolved PAC results for both winter and summer mostly increased from upstream to downstream sites (individual site results were not reported).

Pooled mean site results for dissolved PAC concentrations in tributaries to the Athabasca River increased from 0.009 µg/L upstream of oil sands development to 0.023 µg/L in winter and to 0.202 µ/L in summer downstream. A two-way ANOVA was performed to demonstrate that differences (log transformed) among sites along tributaries were highly significant (P=0.004). More detailed analyses and comparisons were done to indicate that observed differences in downstream samples could be mainly attributed to oil sands development and not to dissolution of PACs from contact with natural oil sands from the McMurray formation exposed along tributary banks.

Kelly et al. (2009) reported similar increases in PAHs in the Athabasca River near oil sands upgrading facilities and tailings ponds in winter (0.031–0.083µg/L) and downstream of new development in summer (0.063–0.135µg/L). Otherwise, they reported that PAC concentrations were low (<0.025 µg/L in winter, <0.030 µg/L in summer) in the Athabasca River, Athabasca Delta, and Lake Athabasca. Kelly et al. (2009) also studied snow melt samples to assess airborne PACs emitted from oil sands operations and these results are discussed in Section 7.2.

There are presently no Canadian guidelines for total PAHs in sediment although the U.S. National Oceanic and Atmospheric Administration (Johnson 2000) recommended a threshold of 1 mg/kg dry weight of total PAHs in marine sediment for protection of estuarine fish populations. The levels of PAHs in sediment of the Athabasca River are about twice those observed to induce liver cancers in fishes (Myers et al. 2003). The concentrations reported are comparable to those that induced mortality, reduce growth rate, and caused pathology in embryos of fathead minnows (*Pimephales promelas*) and white sucker (*Catostomus commersoni*), species which are native to the Athabasca watershed (Colavecchia et al. 2004, 2006). Other studies have shown that PAHs have been associated with a substantial increase in the risk of liver disease, reproductive impairment, and developmental toxicity in fish (e.g., Carls et al. 1999; Meyers et al. 2003). Whether oil sands developments are substantially affecting PAH levels in Athabasca River sediments is currently not clear. If sensitive enough monitoring methods are used and sampling is focused closely enough on development, it seems inevitable that some increase of contaminants produced by these large scale activities should be detectable. Judging whether any such expected detectable increase in levels of some development related contaminants pose a threat to the aquatic ecosystem will be much more challenging.

Timoney and Lee (2009) conclude that their analysis of the RAMP pilot project data demonstrates evidence of increased PAHs in the Muskeg River downstream from oil sands developments. Unfortunately, RAMP did not follow up the 2006 pilot study with SPMDs in the 2007, 2008, and 2009 study years, with the SPMD pilot only being mentioned again in the 2009 RAMP Technical Design and Rationale report (RAMP 2009). The Kelly et al. (2009) results, although not presenting separate results for the Muskeg River supports the Timoney and Lee (2009) hypothesis about higher levels of PAH (or PAC) downstream from oil sands developments. There is clearly a need for RAMP to follow up data collection with SPMDs (or an equivalent integrated sampling approach) to understand the magnitude and specific source of PAH contribution to regional aquatic ecosystems.

Timoney and Lee (2009) and Kelly et al. (2009) both referred to the controversy in Fort Chipewyan concerning apparent elevated cancer rates by noting that PAH are known carcinogens. This matter is discussed in Section 11.3.1, but these references to PAH-related cancer risk, even nuanced as they are, are unfortunate because results from neither study provide any evidence to support a human cancer risk from measured PAH. Recognized carcinogenic PAH comprise a negligible proportion of the PAH that either paper reports. While valid concerns about effects on aquatic organisms from observed PAH concentrations are raised, any extrapolation to or speculation about human cancer risk is unsupported by any of the available toxicological evidence on PAH. Such speculation, in the absence of credible quantitative evidence, does not serve to accurately inform downstream residents and seems likely to create fear.

The most recent study addressing oil sands impacts on regional water quality was released in September of this year (Kelly et al. 2010) and it addresses 13 trace metals (described as toxic priority pollutants or PPE as designated by the U.S. Environmental Protection Agency[7]) measured in snow samples, tributaries and the Athabasca River (AR) in February and June 2008. This study concludes that "*the oil sands industry substantially increases loadings of toxic PPE to the AR and its tributaries via air and water pathways*." This conclusion is set in contrast to conclusions from the annual RAMP reports which generally conclude that oil sands operations are having minimal impacts on downstream water quality.

Judging the comparative merits of these differing findings is difficult because of the limited detail about sampling methods used. This detail is essential for comparing water quality along any river's length which is obviously necessary to draw conclusions about downstream impacts. Rivers are known to be relatively slow to mix transversely across the river cross-section while they mix comparatively rapidly in the vertical cross-section (i.e. top to bottom) because rivers have a large width to depth ratio (Putz and Smith 1998). If there are differences in water quality across a river's cross-section, as there inevitably will be based on contaminants entering from a bank source or tributary entering, performing comparisons of water quality numbers along the length of the river has little meaning without clear explanation of how the river cross-section has been sampled.

RAMP (2010) states with regard to its river sampling: "*Field sampling involved collection of grab samples of water from smaller creeks or rivers, collection of cross-channel composite samples or bank-adjacent grab samples in large rivers…*" Presumably, the Athabasca River is considered a large river so it may involve cross-channel composite samples of an unspecified number, but this statement also allows for the possibility that some Athabasca River data are based on "*bank-adjacent grab sample*." Further details on cross-river sampling strategy for the Athabasca River[8] were provided in RAMP (2009). No details could be found in Kelly et al. (2010) in either the main paper or the accompanying supplementary information about the river water sampling methods employed. Clearly any attempt to compare or contrast water quality results for the Athabasca River between RAMP and Kelly et al (2010) will require better information on the sampling methods used.

Kelly et al. (2010) raise important issues about the interpretations of water quality impacts of oil sands developments by RAMP. Summer sampling suggested three to fourfold increases from upstream to oil sands development sites for chromium, copper, lead, mercury and nickel and 60% (arsenic) to 2.5 fold (cadmium) increases for other metals. Except for a 1.7 fold increase in mercury, increases were not found for any of the metals found to increase in the summer sampling. The limited scope of results

[7] The U.S. Environmental Protection Agency has identified a list of 126 environmental contaminants that are described as priority pollutants - http://water.epa.gov/scitech/swguidance/methods/pollutants.cfm

[8] "*At most stations on the Athabasca mainstem, samples are collected at the east and west banks of the river, given previous studies have shown that cross-channel mixing in the Athabasca River in this reach occurs slowly. A cross-channel composite sample is collected at ATR-FR (upstream of the Firebag River); cross channel composites have also been collected at ATR-DC (upstream of Donald Creek) and ATR-DD (downstream of development) in recent years, although sampling in 2008 at these locations was changed to west and east bank samples, consistent with other, upstream locations on the Athabasca River mainstem.*" RAMP 2009. Note: the comment about cross-channel mixing occurring slowly "*in this reach*" reflects a misunderstanding because cross-channel mixing occurs slowing in any large river.

obtained[9] does not allow firm conclusions to be drawn about the extent of the impact of oil sands operations on the Athabasca River. Clearly, there is a need to resolve the apparent discrepancy in findings because sound environmental management of oil sands operations cannot be achieved without valid water quality monitoring data.

Kelly et al. (2010) allude to human health concerns in the context of their report about toxic priority pollutants being added to the Athabasca River. They acknowledge that none of the metals concentrations measured exceeded any of the applicable Guidelines for Canadian Drinking Water Quality (GCDWQ). Table 8.8 summarizes the findings of Kelly et al. (2010) with regard to observed Athabasca River concentrations and the GCDWQ (Health Canada 2008). This considers only the June 2008 results because the February 2008 results are lower. The GCDWQ are concentrations that are set to allow consumption of 1.5 L of water per day at the maximum acceptable concentration for a 70 year lifetime without causing any significant adverse health effect.

Kelly et al. (2010) report that relevant surface water quality criteria for the protection of aquatic life for some of these metals were exceeded in surface water samples in their study. At the oil sands developed site for June 2008, this was found for cadmium (0.070 ± 0.004 µg/L vs. criterion of 0.033 µg/L), copper (4.5 ± 0.24 µg/L vs criterion of 2 µg/L), lead (2.3 ± 0.085 µg/L vs. criterion of 2 µg/L) and mercury (0.011± 0.00054 µg/L vs. 0.005 µg/L). For the February sample only silver exceeded the protection of aquatic life criterion (0.23 ± 0.18 µg/L vs. criterion of 0.1 µg/L) at the oil sands development site. Confirming the extent to which oil sands developments may be causing metals concentrations in regional rivers and lakes to exceed surface water criteria for the protection of aquatic life is clearly something that must be determined as soon as possible and must be maintained by RAMP on a continuing basis.

Benthic invertebrate communities are monitored through the RAMP because they reflect habitat quality, serve as biological indicators, and are important components of fish habitat (RAMP 2009). Benthic invertebrate communities are a commonly used indicator of aquatic environmental conditions, as they integrate biologically relevant variations in water, sediment and habitat quality. Benthic invertebrates have limited mobility and therefore reflect local conditions and can be used to integrate point sources of inputs or disturbance. They often have a short life span (typically about one year) which allows them to integrate physical and chemical aspects of water quality and sediment quality over annual time periods and provide early warning of possible changes to fish communities (e.g., Kilgour and Barton 1999). The RAMP Benthic Invertebrate Community Surveys focus on characterizing benthic invertebrate communities on the basis of total abundance, taxonomic richness, and relative dominance in areas both downstream and upstream of development (RAMP 2009).

[9] Kelly et al. (2010) reported on one winter and one summer sampling period with upstream characteristics based on 3 samples for each period, development site based on 7 samples, downstream unspecified distances along the Athabasca River based on 6 samples and downstream in Lake Athabasca was based on a single sample for each period in 2008. Drawing any conclusions regarding the meaning of a single sample is certainly unusual for a scientific study.

Table 8.8 Reported Concentrations of metals in the Athabasca River in relation to human health–based drinking water guidelines

		Athabasca River in June 2008 (highest concentrations in Kelly et al. 2010)					
		Upstream of Development		**At Oil Sands Development**		**At Lake Athabasca**	
	Number of Samples	**3**		**7**		**1**	
Metal	**Guidelines for Canadian Drinking Water Quality,* µg/L**	**Mean Concentration µg/L**	**Percent of GCDWQ**	**Mean Concentration µg/L**	**Percent of GCDWQ**	**Concentration µg/L**	**Percent of GCDWQ**
Antimony	6	0.094	1.6%	0.2	3%	0.15	2.5%
Arsenic	10	1.1	11%	1.74	17%	1.2	12%
Cadmium	5	0.028	0.6%	0.07	1.4%	0.038	0.8%
Chromium	50	0.78	1.6%	3.1	6.2%	1.3	2.6%
Copper**	1000	1.4	0.1%	4.5	0.5%	2.6	0.3%
Lead	10	0.60	6%	2.3	23%	1.0	10%
Mercury	1	0.0033	0.3%	0.011	1.1%	0.0039	0.4%
Selenium	10	<0.5 µg/L	0%	0.52	5.2%	2.1	21%
Zinc**	5000	<10 µg/L	0%	13	0.3%	<10 µg/L	0%

*maximum acceptable concentration is set to allow daily of consumption of 1.5 L of drinking water at that concentration for a 70 year lifetime without any significant adverse health effects
** maximum acceptable concentration is set based on aesthetic criteria, not adverse health effects

Source: Kelly et al. 2010; Health Canada 2008

In 2009, the RAMP monitored benthic invertebrate communities in 11 watersheds/regions (RAMP 2009). For nine of these sites, variations in benthic invertebrate community measurement endpoints were classified as negligible-low because the measurement endpoints in fall 2009 were within the range of historical values for these reaches, and there were no trends over time in the measurement endpoints which would point to a degradation of community composition. Variations in benthic invertebrate community measurement endpoints at lower Poplar Creek were classified as moderate whereas Isadore's Lake and the baseline lakes region were classified as high. Types of endpoints showing major variations included diversity, evenness, %EPT (mayflies, stoneflies, caddisflies), number of taxa, and Simpson's diversity index when compared to upstream conditions. Follow up studies are necessary at Poplar Creek and Isadore's Lake to see if the changes persist over time and to identify cause and effect.

Much emphasis has been placed on evaluation of fish populations as they reflect and integrate the overall condition of the aquatic environment, they are biological indicators of ecosystem integrity and are a highly-valued resource in the region. Fish are also an important subsistence and recreational resource and come under close scrutiny from regulators, Aboriginal peoples, and the general public. Particular emphasis is placed on the selected key fish species based on their ecological importance and value to local communities. The most extensive data set in this regard is available through the RAMP. Here fish are collected and assessed for health status through performance indicators such as growth, reproduction, and survival of fish in test areas downstream of development relative to baseline and/or historical performance data. Measures commonly undertaken include physical condition, population age, and length/weight comparisons and reproductive status in sentinel fish species. Associated with the fish collection, there is often an assessment of suitability of fisheries resources in the Athabasca oil sands region for human consumption through tissue sampling for organic and inorganic chemicals.

In general, the result of the RAMP 2009 fish population assessment was that statistically significant differences were observed among years for condition and length-frequency distribution for many of the key indicator fish species. However, RAMP further conclude that variability of these measurement endpoints among years does not indicate consistent negative or positive changes in fish populations and likely reflect natural variability over time. There is concern that the results of the 2009 RAMP report and their previous reports do not provide an integrated long-term assessment of fish populations in the oil sands region. These concerns were raised in an external review of the RAMP (Ayles et al. 2004) and continue to be problematic in the 2009 report. These concerns pertain to the experimental design including selection of sampling sites, statistical approaches, and failure to provide a power analysis. The survey approach used in the RAMP program does not clearly provide the most robust assessment of fish populations. Many endpoints and lessons learned from extensive monitoring programs such as the Environmental Effects Monitoring program for the pulp and paper sector (Environment Canada 2005) have not been adopted by RAMP. For example, much of the information on the impacts of pulp mill effluents has been derived from assessing changes in investment in gonadal growth (measurement of gonadosomatic index) or changes in energy metabolism (measurement of condition factor and hepatosomatic index). The RAMP sampling regime only includes these measures in a small portion of the studies. Other biomarkers, such as induction of the P4501A1 that are commonly measured to assess exposure to hydrocarbons which would be agonists of the aryl

hydrocarbon receptor are generally not incorporated as part of the RAMP. Focused endpoints such as these would assist in establishing whether there was significant elevated exposure to chemicals associated with OSPW in the waters downstream of oil sands development sufficient to pose a risk to the aquatic ecosystem.

Previous studies have shown that fish inhabiting the Athabasca region are exposed to PAHs. Altered biochemical responses (ethoxyresorufin O-deethylase activities) have been demonstrated in several fish species native to the Athabasca River (Tetreault et al. 2003; Colavecchia et al. 2004). Altered biochemical and reproductive responses in native fish species residing in the Athabasca oil sands were found relative to fish from reference areas (Tetreault et al. 2003). Native slimy sculpin (*Cottus cognatus*) and pearl dace (*Semotilus margarita*) residing within natural oil sands and developed sites showed reductions in steroid production and increased ethoxyresorufin-O-deethylase (EROD) activity (a biomarker of chemical exposure activity) relative to reference areas. Wild adult longnose suckers (*Catostomus catostomus*) captured in oil sands areas demonstrated a 15-fold increase in EROD activity as compared to reference fish (Parrott et al. 1999). These findings illustrate that native fish species are exposed to naturally occurring oil sands related compounds, consistent with PAH exposure. Certainly more work on the long term consequences of exposure to chemicals derived from oil sands operations are warranted to determine the impact of oil sands development relative to the natural background oil sands exposure.

Surface water is potentially vulnerable to acidification from atmospheric deposition of SO_2 and NO_x. The RAMP addresses this issue with its Acid-Sensitive Lakes (ASL) component. In late August 2009, the water from 50 lakes and ponds within the RAMP region of study, and beyond the region to obtain baseline values, was sampled and analyzed for a series of inorganic components and metals. The sensitivity of the lakes to acidification was assessed according to three separate classification systems: Gran alkalinity (acid-neutralizing capacity), pH, and critical load. The critical load was expressed in units of keq H^+/ha/y and defined as the highest load of acid deposition that will not cause long-term changes in lake chemistry and biology. (More detail on the estimation of the critical load is given in RAMP [2009].) Critical load was calculated for each lake with a steady-state chemistry model (RAMP 2009). That model requires an evaluation of the runoff to the lake, which is computed by RAMP (2009) using either a standard hydrometric (water balance) method or from the analysis of heavy isotopes of oxygen and hydrogen in the lake water. Results from the assessment indicate that the most acid-sensitive lakes are located in upland areas, such as the Muskeg River Uplands, while the least acid-sensitive lakes are found elsewhere in the region, in particular in the area west of Fort McMurray. Based on the classification proposed by RAMP (2009), over 60% of the lakes in the ASL component are considered highly sensitive or moderately sensitive to acidification.

To determine if there are signs of lake acidification, RAMP (2009) identified measurement endpoints, which are the chemical components that can be best related to changes in the acidity of a lake. RAMP (2009) defined the following six measurement endpoints: Gran alkalinity, base cation concentrations, nitrate plus nitrite, sulphate, dissolved organic carbon, and dissolved aluminum. Using the values of these measurement endpoints for each lake as whole, RAMP (2009) conducted an analysis of variance for the 2002–2009 period. Their analysis indicates that there haven’t been any significant variations in

composition of these measurement endpoints for lakes taken as a whole since this phase of the RAMP started in 2002, except for concentrations of nitrate and dissolved organic carbon (RAMP 2009). The average concentration of nitrate has been decreasing since 2002 and, since the trend is contrary to that resulting from acidification, RAMP (2009) concludes that there is no indication that acidification from nitrogen deposition is occurring in the lakes. The concentration of dissolved organic carbon has decreased significantly in the lakes studied by RAMP, particularly in the northeast of the Fort McMurray subregion. On the other hand, a similar decline has been observed in lakes in the Caribou Mountains and Canadian Shield subregion, which are used as baseline because they have little exposure to SO_2-NO_x emissions from oil sands developments. RAMP (2009) concludes that this significant decline in the concentration of dissolved organic carbon is not caused by acidification but rather has a natural origin, which currently remains unidentified.

The RAMP has been undergoing its second external scientific review in 2009–2010 (RAMP 2009) following the first critical review by Ayles et al. (2004) and RAMP has been experiencing continuing criticism (Schindler 2010). The findings of second external review of RAMP and meaningful action upon constructive recommendations from that review will be critically important to dealing with the wide range of monitoring challenges that RAMP faces for identifying any impacts on the aquatic environment by oil sands development. Both the federal and provincial panels established in October 2010 to review RAMP will presumably also have some recommendations to be considered.

The impact of surface mining operations on regional groundwater quality is still poorly known. A few studies mentioned previously have investigated contaminant plumes in groundwater (for example, Oiffer et al. 2009) but their extent is local, close to one mining operation. Removing the overburden has an impact on groundwater and surface water flow dynamics, as stated previously. There are also concerns that water quality can be affected by the changing flow dynamics, but there is a lack of data to assess those potential changes. In addition to contaminants present in the OSPW, variations in water temperature and dissolved oxygen levels caused by mining activities might have a negative impact on surface water. These concerns remain speculative and more work and data will be required to assess the regional groundwater quality picture.

The main overriding concern is whether tailings ponds leak substantially to affect groundwater and ultimately regional surface waters. This issue needs to be addressed in a thorough, coordinated study. Likewise, the EPEA approval reporting of monitoring for tailings pond seepage should be made publicly available to address this valid concern.

8.5 Summary of Main Finding and Knowledge Gaps

There are substantial knowledge gaps related to the impact of oil sands development on the water quantity and quality within the oil sands region. The main findings and associated knowledge gaps for this topic are:

- More research is needed to better quantify the groundwater–surface water flow dynamics in the Fort McMurray region, to help assess the impact of oil sands operations.

- Current allocation of water from the Athabasca River, for all usages, is 3.5% of the total annual average river flow, with allocations for oil sands mining projects accounting for about 2.2% of total flow. A framework has been proposed to manage, and limit as necessary, water extraction from the Athabasca River, to maintain minimum flow rates.
- There is no evidence of a framework similar to that for the Athabasca River to limit groundwater extraction related to surface mining and thereby limit the permitted groundwater level declines.
- Groundwater concerns are currently only considered at the local scale. A regional groundwater framework still has to be developed for the oil sands. CEMA has taken the first step in establishing a framework and identifying current knowledge gaps with respect to groundwater.
- The issue of seepage of OSPW into the Athabasca River could be clarified considerably if results from annual environmental assessments under EPEA approval reporting were publicly available. Current observations, however, indicate no negative impact of OSPW to the Athabasca River.
- While the acute toxicity of constituents within the tailings ponds attenuates quickly, there is evidence that in experimental exposures the OSPW from tailings ponds constructed more than 15 years ago continues to negatively affect fish health by promoting adverse developmental, biochemical, morphological, and reproductive responses in fish.
- Among contaminants present in OSPW, NA are the cause for most concern. Because NA comprise a mixture that is variable, complex, and poorly defined, it is challenging to generate a meaningful regulatory standard for NA that could be applied to track NA migration in surface water or groundwater. In addition to those analytical difficulties, the transport mechanisms and persistence of NA in groundwater are still poorly understood. Equally, the chronic biological effects of different forms of NA are poorly defined.
- EPLs represent an unproven concept despite having been approved in principle by the ERCB in 1993 subject to successful demonstration. Because they have not yet been demonstrated, their viability cannot be currently assessed. Given the scale of these developments and the anticipation that EPLs will represent a significant hazard for decades, improved methods of assessment and possible remediation efforts must be given high priority for future research needs. In particular, developing a receiving water standard for NA should be a priority.
- To date, the downstream effects of the oil sands developments on water quality and responses of biota have been judged to be minimal by RAMP and by some other researchers over the past decade. The Kelly et al. (2009, 2010) studies which have been critical of RAMP have shown changes attributed to oil sands development in comparatively low levels of contaminants with a limited data set. Overall, there is considerable uncertainty in the assessment of water quality responses in the downstream environment. The 2009–2010 external review of the RAMP and the recently announced Federal and Provincial review panels must be followed by meaningful

action to deal with the wide range of monitoring challenges that RAMP faces for identifying any impacts of oil sands development on the aquatic environment.

9. LAND RECLAMATION

9.1 Introduction

Companies operating in Alberta oil sands are required to return disturbed land to equivalent land capability. Various interpretations associated with the phrase *equivalent land capability* have affected, and will continue to affect, development and acceptance of the landscape that could be deemed to have met that regulatory standard. Thus interpretation will have significant implications for acceptable land reclamation practices and eventual certification of reclaimed sites.

Even if reclaimed ecosystems to be developed after oil sands mining could be agreed upon, there is major scepticism whether reclamation to equivalent land capability could be achieved in a reasonable time period. This is particularly germane given the small amount of land certified to date in the oil sands. With so little certified reclaimed land to evaluate, judging the likelihood of reclamation to any interpretation of equivalent land capability can only be based on land that has been reclaimed but not certified and on reclamation research. This review has mainly relied on the reclamation research because it is associated with data collected by independent third parties, not oil sands companies.

9.2 Oil Sands Reclamation Requirements and Determination of Success

9.2.1 Oil Sands Reclamation Requirements

The Government of Alberta views industrial operations, including oil sands operations, as temporary land use activities. Oil sands operations currently require conservation, reclamation, and reclamation certification according to the Alberta Environmental Protection and Enhancement Act (EPEA). The Conservation and Reclamation Regulation (AR 115/93) states that post-mining landscapes must be reclaimed to "*an equivalent land capability*" (EPEA 2009). If the land meets or exceeds reclamation standards, the company may apply for a reclamation certificate, which may be issued following review of the application and inspection of the land. The company may then be free from further obligations after a period of time specified in the Regulation.

Based on industry applications and subsequent regulatory approvals from Alberta Environment (AENV), equivalent land capability in the oil sands implies post-mining landscapes will be similar to undisturbed boreal forest. Although the Act and Regulation governing the oil sands do not specifically require reclamation to boreal forest, this restrictive view of reclamation options arose from policy and practice and is reflected in existing applications and approvals. Numerous studies on undisturbed land in the Alberta oil sands region provide detail of the biophysical conditions of functional terrestrial and wetland ecosystems, and information required to develop a realistic template for reclamation.

A reclaimed landscape similar in structure, function, and composition to an undisturbed landscape may appear to be a relatively straightforward regulatory standard; however, it is fraught with controversy over interpretations of equivalent land capability. Various interpretations of the regulatory standard create serious problems regarding what landscapes could be acceptable from regulatory, industrial, public, and cultural perspectives. A parallel and entangled debate has occurred for decades over reclamation versus restoration as the means of achieving equivalent land capability or the trajectory to

develop towards it. Use of the terms *reclamation* or *restoration* has implications for what landscape could realistically be constructed, and the time frame over which it could be expected to develop.

Thus, achieving clarity and consensus in definitions is not strictly a semantic or academic exercise. When stakeholders disagree, definitions take on deeper meaning and serve as continued fuel in an already heated debate. Terms used for reclamation and their meanings have significant impacts on various parties as they relate to project cost, time-frame, and measurements of success. To better understand these issues, several key definitions are provided and discussed in the following sections.

9.2.2 Equivalent Land Capability

Land capability was defined in the Government of Alberta Conservation and Reclamation Regulation (AR 115/93) as "*the ability of land to support a given land use, based on an evaluation of the physical, chemical and biological characteristics of the land, including topography, drainage, hydrology, soils and vegetation*" (EPEA 2009). Equivalent land capability is "*the ability of the land to support various land uses after conservation and reclamation is similar to the ability that existed prior to any activity being conducted on the land, but that the individual land uses will not necessarily be identical.*" In these definitions, land is defined as "*terrestrial, semi-aquatic and aquatic landscapes.*"

In oil sands reclamation, capability is currently measured by the Land Capability Classification for Forest Ecosystems (LCCS) developed for forest ecosystems on natural and reclaimed lands in the Athabasca boreal region (CEMA 2006). The focus is on commercial forestry, particularly for soil, erosion, and tree growth. Use of this document as a measure of reclamation creates concern that economic or productivity factors dictate the reclaimed target landscape of a forested ecosystem for merchantable timber and diminish the value of wetlands and other natural habitats. Land might be considered improved if it can support merchantable timber, regardless of pre-disturbance conditions.

9.2.3 Reclamation

Reclamation has long been defined as "*the process of reconverting disturbed land to its former or other productive uses*" (Powter 2002). The regulatory definition states reclamation must include "*all practicable and reasonable methods of designing and conducting an activity to ensure: stable, non-hazardous, non erodible, favourably drained soil conditions and equivalent land capability*" (Powter 2002); "*removal of equipment or buildings or other structures and appurtenances; decontamination of buildings or other structures or other appurtenances, or land or water; the stabilization, contouring, maintenance, conditioning or reconstruction of the surface of land; any other procedure, operation or requirement specified in the regulations*" (EPEA 2009; Powter 2002).

On its oil sands website, AENV (2010) defines reclamation as the "*return of land and environmental values to a mining site after resources have been extracted*"; noting the process commonly includes "*recontouring or reshaping land to a natural appearance, replacing topsoil and planting native grasses, trees and ground covers.*" Numerous modified definitions exist in regulatory documents. Although regulatory definitions of reclamation are very goal-oriented and seek to be all-encompassing, the many versions in existence create unnecessary confusion.

Outside the regulatory realm, the Society for Ecological Restoration (SER) says the term reclamation has broad application and is commonly used for mined lands in North America and the United Kingdom. SER indicates reclamation objectives are "*stabilization of the terrain, assurance of public safety, aesthetic improvement, and usually a return of the land to what, within the regional context, is considered to be a useful purpose*" (SER 2004). This definition lacks inclusion of the changes necessary to return a disturbed system to the structure, function, and composition required for former or other productive uses. The SER definition differs from the academic definition, wherein reclamation must include all disturbed components and processes of an ecosystem, including, but not limited to, soils, hydrology, flora, and fauna.

The confusion is exacerbated when other stakeholders develop and use their own definitions of land reclamation. For example, Golder Associates (2000) say reclamation is to "*achieve maintenance free, self sustaining ecosystems with capabilities equal to or better than pre disturbance conditions.*" Industry Canada (2010) and the National Energy Board (2006) define reclamation as "*returning disturbed land to a stable, biologically productive state.*" Alberta, Naturally (2010) defines it as "*a method used to return disturbed land to a state where it is useful once again.*"

9.2.4 Restoration

Restoration, most commonly called ecological restoration, is historically defined as the act of returning to a former position or condition, or by the Government of Alberta as "*the process of restoring site conditions as they were before the land disturbance*" (Powter 2002). There is a broad misconception that restoration means abiotic and biotic site conditions are to be exactly as prior to land disturbance to the smallest detail. Hence the question emerges whether restoration is physically possible and if there is any utility in using a term with such a restricted perspective. Consequently, reclamation has become favoured over restoration within the reclamation industry and regulatory bodies of Alberta.

SER (2004) defines ecological restoration as "*the process of assisting the recovery of an ecosystem that has been degraded, damaged or destroyed*"; viewing it as an "*intentional activity that initiates or accelerates*" recovery of ecosystem health, integrity, and sustainability, and "*attempts to return an ecosystem to its historic trajectory.*" SER believes its definition allows varied approaches, "*while giving prominence to the historically rich idea of recovery.*" SER says an ecosystem is restored, "*when it contains sufficient biotic and abiotic resources to continue its development without further assistance*"; that it "*will sustain itself structurally and functionally,*" demonstrating "*resilience to normal ranges of environmental stress and disturbance,*" and that it "*will interact with contiguous ecosystems in biotic and abiotic flows and cultural interactions.*" SER says that although numerous attributes determine when a site is restored, "*the full expression of all of these attributes is not essential to demonstrate restoration,*" and "*it is only necessary for these attributes to demonstrate an appropriate trajectory of ecosystem development towards the intended goals or reference.*"

The attributes SER refers to include "*a characteristic assemblage of indigenous species*" that occur in reference ecosystems and provide structure and functional groups for continued development and/or stability of the restored ecosystem; any missing groups must have "*the potential to colonize by natural means.*" The physical environment must be capable of "*sustaining reproducing populations of the*

species necessary for its continued stability or development along the desired trajectory." The restored ecosystem must be "*suitably integrated into a larger ecological matrix or landscape*" and "*sufficiently resilient to endure the normal periodic stress events in the local environment*" that maintain ecosystem integrity, and must be self-sustaining to the same degree as its reference ecosystem (SER 2004).

SER indicates other attributes can be considered if they are identified as goals of the restoration. For example, if a restoration goal is to provide specified natural goods and services for social benefit in a sustainable manner, the restored ecosystem can serve as natural capital for accrual of these goods and services. Thus, oil sands reclamation to merchantable timber or other uses could be restoration.

9.2.5 Native vs. Non-Native Plant Species

Revegetation is a key part of reclamation or restoration. Revegetation, simply defined, is to provide barren or denuded land with a vegetation cover. The Government of Alberta defines it as establishment of vegetation which replaces the original ground cover after disturbance (Powter 2002). It can be a direct anthropogenic activity with seeding and transplanting or occur without human intervention. Natural recovery, sometimes called spontaneous revegetation, is the natural reestablishment of plants, with no deliberate introduction of propagules and seeds, and no other anthropogenic involvement, including exclusion of herbivores and other natural ecosystem fauna.

The choice of plant species, particularly their origin, is important. The biggest controversy regards use of native versus non-native species and their definitions. As with most other terms used in reclamation and restoration, there are many interpretations. The potential impact of climate change on planting recommendations and nativeness, especially for the highly restrictive requirements placed on tree seed sources, may well become an issue in the future.

Native or indigenous species were "*part of an area's original fauna or flora*" (Powter 2002). There is much debate about how far back in time species are considered "*original*." After the last glaciation or prior to 1492, the beginning of formal North American colonization, are generally accepted. Native species may be those in a specific ecoregion or habitat and of a specific provenance. Regulators define a native plant as "*occurring within its historic range; or in an extension of that range bounded by the dispersal potential of the taxon and under the condition that the extension of that taxon is not known to be related to, and cannot be reasonably attributable to, human activities*" (Powter 2002).

Non-native species are not part of an area's original flora or fauna and are beyond their native range or natural zone of potential dispersal including "*all domesticated and feral species and all hybrids except for naturally occurring crosses between native species*" (Powter 2002). Numerous terms with subtle differences define them. An alien species "*did not originally occur in an area where it is now established,"* but *"arrived directly or indirectly by human activity*" (Powter 2002). Agronomic species have "*undergone human selection for economically important characteristics*" such as biomass and seed yield, nutritional quality, erosion control, aesthetic quality, and establishment ease. Exotic species are "*not native to the province*" and "*not native within the natural region*" (Powter 2002).

Plants may be defined by their behaviour. An invasive plant "*has moved into a habitat and reproduced so aggressively that it has displaced the original structure of the vegetation community*" (Powter

2002). It is often defined as a plant spreading without direct human assistance in natural and semi-natural habitats to produce a significant change in composition, structure, or ecosystem process. A naturalized plant is introduced from other areas; it has become established in, and more or less adapted to, a given region by long continued growth there. These species thus do not become invasive.

Many view ecological restoration as only including native species, whereas SER indicates in "*restored cultural ecosystems, allowances can be made for exotic domesticated species and non invasive ruderal and segetal species that presumably co-evolved with them*" (SER 2004). SER clearly articulates that "*in cultural landscapes, exotic species are frequently an integral part of the ecosystem,*" since "*some exotic species were introduced centuries ago by human or non human agents and have become naturalized, so that their status as an exotic is debatable.*" SER says "*other species have migrated in and out of the region in response to climatic fluctuations during the Holocene, and can scarcely be regarded as exotics,*" since "*even if all exotic species are removed from a restoration site, the opportunity for re-invasion may remain high.*" Thus "*it becomes essential for a policy to be developed for each exotic species present, based upon biological, economic and logistical realities.*"

There is concern reclaimed oil sands, including the site with a reclamation certificate, contain non-native species. SER states that "*since ecological restoration attempts to recover as much historical authenticity as can be reasonably accommodated, the reduction or elimination of exotic species at restoration project sites is highly desirable*" (SER 2004). SER recognizes "*financial and logistical constraints often exist, and it is important to be realistic and pragmatic in approaching exotic species control.*" Thus the focus for determining which plant species should be in the reclaimed system should be on the goals for its success, rather than elimination, by definition, of specific species.

9.2.6 Reference Ecosystems

Equivalent land capability addresses whether a mined oil sands landscape will be reclaimed or restored, and whether native and/or non-native plant species will be used. It addresses reference ecosystems (what was there before disturbance or some model to be reclaimed for a specific end land use) and target ecosystems (what is expected after reclamation to meet end land use requirements). The end land use reference ecosystem will have a huge impact on whether reclamation is achieved, since it serves as the model for planning reclamation and success evaluation.

Identification or development of target ecosystems and trajectories are required for reclamation, particularly when multiple sites are to be reclaimed in a large area over time. Since no single prescription can be effective on all sites, target ecosites should reflect edaphic and topographic variability of the area; each would be detailed in composition and structure, including soil and vegetation properties. Time for reclamation could vary with ecosite, some taking longer to reach a target than others. Thus temporal and spatial aspects of ecosite development, including trajectories, should be included in reclamation planning and evaluation to avoid unrealistic expectations. From a regulatory perspective, there is an important differentiation between "*to be reclaimed*" and "*to reach a target,*" with reclamation certification generally focused on a trajectory, not a target. In 1998, to provide a clear goal for plant composition of reclaimed sites, the Oil Sands Vegetation Reclamation Committee identified 15 target ecosites for tailings sand and overburden sites (Table 9.1).

Table 9.1 Target ecosites for reclamation of the oil sands region

Landscape Features	**Soil Capability Class**	**Hydrologic Regime**	**Target Ecosite Phase**	
tailings sand, crests	4	subxeric	A1	lichen, jack pine
tailings sand slope, south aspect	4	subxeric, submesic	B1	blueberry, jack pine - aspen
tailings sand slope, north aspect	3	subxeric, submesic	B2 B3 B4	blueberry, aspen (white birch) blueberry, aspen - white spruce blueberry, white spruce - jack pine
overburden, low organic	3	mesic	C1	labrador tea - mesic jack pine - black spruce
overburden, south aspect	3-2	mesic	D1	low bush cranberry, aspen
overburden, north aspect	3-2	mesic	D2	low bush cranberry, aspen - white spruce
overburden, north aspect	3-2	mesic	D3	low bush cranberry, white spruce
near level overburden or tailings sand	3-2	subhygric, mesic	E1	dogwood, balsam poplar - aspen
near level overburden or tailings sand	3-2-1	subhygric, mesic	E2 E3	dogwood, balsam poplar - white spruce dogwood, white spruce
near level overburden or tailings sand	2-1	subhygric	F1	horsetail, balsam poplar - aspen
lower slope position			F2 F3	horsetail balsam poplar - white spruce horsetail, white spruce

Source: adapted from Table 3.4 in Oil Sands Vegetation Reclamation Committee (1998) Guidelines for Reclamation to Forest Vegetation in the Athabasca Oil Sands Region.

Spatial and temporal progressions of species that occur with natural development are considered necessary for establishment and persistence of late successional species. Skipping early successional stages is common in reclamation. For example, adding amendments to soil speeds its development; planting mid to late successional species speeds plant community development. There is concern essential elements or links may be missed with rapid reclamation, such as microbial activity enhancing survival of woody species. Thus monitoring to determine reclamation achievement must be process-oriented and consider interrelationships. Ecosystem development components should not be used in regulatory requirements if they are easy to miss or could lead to semantic and technical arguments. Key indicators of reference ecosite trajectories would need to be used in the regulatory context.

9.2.7 A Changing Ecosystem Paradigm

When developing end land use goals and landscapes for the oil sands, the dynamic nature of the world in which reclamation is taking place and being evaluated must be considered. This is often difficult for stakeholders who remember what the landscape looked like before mining and expect that same landscape will be there after reclamation. It is difficult for local stakeholders to consider that if humans dramatically alter the landscape, it may be necessary to reclaim in an equally dramatic way. Individual stakeholders will remember different details and foci, further complicating the ability to develop

reclamation plans, determine reclamation success, and communicate both to a diverse audience.

Johnson and Miyanishi (2008) suggest post-mining oil sands are not a restoration problem, but require engineering or reconstruction of new landscape scale ecosystems. They argue ecosystems constantly change in composition as they adjust to changing environments (Williams et al. 2007; Davis 1976), so it is difficult to set benchmarks based on some past or present time with a presumed composition and environment. They suggest not recreating the pre-disturbance landscape but to "*construct a landscape in which the physical environment of geomorphic, hydrological and biogeochemical processes will provide habitat for plants, fungi and animals to develop and be sustainable*." They say the current approach to oil sands reclamation is based on literature, previous practice elsewhere, and preliminary results from small-scale, short-term studies. Revegetation is based on environmental gradients and boreal mixed-wood studies assuming vegetation will develop along certain successional pathways. Species believed to represent successional stages are planted to ensure succession proceeds. Given the rate of change in developing boreal ecosystems, they predict the oil sands will require >100 years for main biotic components to mature and > 500 years for weathering and geomorphological processes.

Choi et al. (2008) argue restoration with past-focused, idealistic, and/or ad hoc goals may not work because an ecosystem restored to a past environment is not likely sustainable in present or future environments. They suggest a recomposition of isolated and fragmented naturalistic patches is not likely to restore ecosystem functions, and unrealistic goals and work plans are not likely to gain public support. They view historical information as a useful guideline, not a straitjacket for projecting restoration goals and trajectories. They strongly advocate restoration should acknowledge the changing and unpredictable environment, assume the dynamic nature of ecological communities with multiple goals and trajectories, connect landscape elements for reinstating ecosystem structure and function, and seek public support for setting realistic goals and scopes. Choi et al. believe these measures will provide a realistic, ecologically sound, economically feasible, and socially acceptable restoration goal.

The literature abounds with conceptual frameworks and successional models for restoration trajectories and outcomes. Since ecological succession is more typically deterministic than stochastic, generally directional, and often reticulate, regressive, or cyclic (Choi et al. 2008), ecosystem processes do not necessarily develop in an orderly way towards single endpoints but rapidly undergo transitions between metastable states toward multiple, unpredictable endpoints (Suding and Gross 2006; Suding et al. 2003; Hobbs and Norton 1996). Gleason's (1926) individualistic and Connell and Slatyer's (1977) facilitation, inhibition, and tolerance models of succession provide flexibility for setting multiple trajectories, as evidenced by facilitation, inhibition, and tolerance pathways in human-aided succession on mined sites (Wali 1999; Choi and Pavlovic 1998; Cairns and Heckman 1996; Choi and Wali 1995).

Restoration in many jurisdictions and over many types of disturbances, has focused on reinstating abiotic functions, assuming a pre-disturbance return of floral and faunal species. With the "if you build it they will come" mind set (Choi et al. 2008), many projects re-established abiotic components, but desired plant species did not return and undesired species quickly dominated (Levine et al. 2006). Johnson and Miyanishi (2008) iterate the composition and shape of recreated landscape are unknown, and if reclamation occurs on independent leases, problems occur in connecting small reclaimed patches. Burton et al. (2003) suggest vegetation will grow on eroded or unweathered surfaces and

orderly succession to climax vegetation is not the current understanding of boreal forest dynamics.

Johnson and Miyanishi (2008) suggest traditional small-scale remediation and restoration methods are not designed for large-scale landscape recreations, such as the oil sands. They advocate development of a knowledge base for recreating physical and ecological processes that operate within bounds, providing biogeosystems and ecosystem services desired as the end land use, rather than trying to restore pre-disturbance floral and faunal composition. They stress the need to study energy flow and trophic structure of recreated ecosystems rather than assume those ecosystems will be the same as the pre-disturbance ecosystems, since interactions between biotic and abiotic components in young plant communities may have very different key drivers from a more mature ecosystem (Grace et al. 2007).

Factors to consider in developing a future-aimed ecosystem reconstruction approach for Alberta oil sands are thus numerous and far reaching. For example, predicted and occurring changes in weather patterns can affect restoration outcomes and obscure goals; soils are being enriched by atmospheric nitrogen depositions due to oil sands operations, which could add uncertainty to future vegetation development trajectories once operations providing nitrogen are completed; and desired plant species of cultural and ecological importance today may be unimportant or less important in future decades.

In oil sands reclamation, many questions emanate from a forward-thinking perspective. If oil sands reclamation had clearly defined goals, unriddled by semantics and opposing perspectives, would Albertans reassess what is needed and what is achievable and separate that from what is idealized and desired? Would achievability be clearly articulated along timelines? Could stakeholders step away from their preconceived past-focused desires and merge their needs for a newly developed landscape?

9.2.8 Definition Interpretation and Achievement of Equivalent Land Capability and Reclamation

The discrepancy over definitions and interpretation of terms associated with oil sands reclamation has created a broad barrier, hindering a critical collective agreement on the goal of oil sands reclamation, how, and over what time, achievement of that goal should be assessed, what is biophysically possible, and who should be involved in determining targets and trajectories. Ultimately, interpretation of reclamation standards has potential to shape decisions and actions of all stakeholders in the oil sands. These interpretations allow oil sands critics to say they have not reclaimed to appropriate standards by focusing on different definitions of reclamation and restoration than those of regulators and operators. They allow operators to further interpret what is expected and required based on what they think can be accomplished in a reasonable time-frame at a reasonable cost. They allow policy makers to balance industrial development with environmental protection and economic development. Such interpretations allow all stakeholders to think they are right and therefore never reach an agreement. According to the Pembina Institute (Grant et al. 2008), Albertans' expectations for the oil sands are more restoration than reclamation; however, this assertion is not supported by any survey or documentation, nor is it clear whose definitions of restoration or reclamation are being used in making this assertion.

An acceptable end land use with its structure, function, and composition clearly detailed at the outset of mine development would clarify reclamation goals and expectations. Knowing the target, what it looks like, and that it is achievable in a given time-frame, could focus stakeholders to work towards the same objectives, rather than on interpretations of restoration, reclamation, or equivalent capability. It

would be easier to determine if reclamation was achieved or was on an appropriate trajectory because it could be measured. A clear target could provide greater certainty for industry to prepare and implement reclamation plans and would provide a necessary focus for reclamation research. For example, simply stated, reclamation of boreal forest would require trees; reclamation of merchantable timber forest would require specific tree species growing at acceptable rates; reclamation of forest ecosites would require diverse terrestrial and wetland flora and fauna and soil processes.

The time-frame for oil sands reclamation will significantly impact liabilities, risks, and costs for the operator. Restoration to pre-disturbance conditions suggests a long liability period with low probability of success, whereas reclamation to a specified end land use suggests an achievable goal in a defined time period. Yet both can mean the same thing. If an agreed-upon, specific end land use was targeted, operators could more accurately assess liabilities, risks, and costs. For example, there is much debate over recreating disturbed peatlands, fens, and bogs versus improving land productivity with upland forests. If oil sands developers were required to restore peatlands and other wetlands, they may not apply for a mine approval, since creating upland forest is viewed as an achievable reclamation outcome whereas creating peatland and wetlands is questioned. The cost of equivalent land capability via historical interpretations of restoration versus reclamation can vary considerably. For example, cost of native plant seed could be considerably higher than cost of non-native plant seed. With clear end land use goals and timelines, an operator would be undertaking mine development knowing what is needed at the end and regulators and other stakeholders would know what to expect and when to expect it. Estimation of reclamation costs for defining financial security (Section 11.1) would be more efficient.

If stakeholders agreed upon end land uses and equivalent land capability for a mining operation, a more clearly defined monitoring program and success indicators could also be developed and agreed upon. If vegetation composition and performance were used to determine equivalent land capability, it could be determined in a few years for herbaceous vegetation versus a decade or more for a forest. In ecological restoration, equivalent land capability determination time-lines and monitoring complexity increase as ecosystem function must be evaluated, and its composition and structure would be more complex. The potential for debate over data and its interpretation increases with increased assessment complexity, but more importantly it increases when there are no defined and accepted end land uses with defined and accepted goal achievement markers. Monitoring must address the degree of progress towards reclamation by determining elements (vegetation, soils, hydrology, fauna, etc.) of acceptable trajectories over time indicating the ecosystem is not meeting, is on its way to meeting, or has met, the reclamation criteria. There is sufficient research data to develop the details of these trajectories.

Thus all stakeholders should use accepted definitions of the terms associated with oil sands mining regulatory requirements (e.g., reclamation, restoration, equivalent land capability, native species). Because there are currently so many versions of definitions, standardization would be required, with acceptance by stakeholders, and understanding of how terms would be applied to existing reclaimed lands. Acceptance would be less difficult if all stakeholders were involved to develop consensus.

Before approval of an oil sands operation is granted, end land uses and equivalent land capability should be clearly defined, considering various ecosites required on the pre-disturbance landscape to meet end land use objectives in an ecologically sustainable way. Clearly defined and standardized

evaluation parameters, criteria, and methods for assessment would enhance stakeholder understanding of what constitutes reclamation, the trajectories it can take over time, and when equivalent land capability, and thus reclamation, have been achieved. Clearly understood and accepted timelines over which trajectories could occur would aid in assessing if a site is progressing towards its intended goal.

These expectations are not unlike the well-established requirements for reclamation in other Alberta oil and gas developments. For example, detailed criteria for reclamation of well sites and associated facilities have existed for decades and have been modified several time based on experience from regulators, operators, and reclamation assessors. Other jurisdictions have good examples of detailed criteria, such as those established by the U.S. Army Corps of Engineers. Of course these standardizations would not be static, changing as any other parameter in society changes with time and new knowledge.

9.3 Reclamation Certification

9.3.1 Reclamation Certification To Date

Many non-industrial and non-regulatory stakeholders have expressed considerable concern that so little land has been certified as reclaimed since the Alberta oil sands were first developed. As of 2008, 60,234 ha have been disturbed (Table 9.2) (AENV 2010). Although 6,687 ha (11.1%) are considered to be reclaimed by industry, and some regulators, to date a reclamation certificate has been applied for and issued for only 104 ha.

Table 9.2 Alberta oil sands disturbance, reclamation and certification areas (ha) to date.

Year End	Disturbed	Reclaimed	Certified	Active	Percent Reclaimed	Annual Reclaimed	Annual Disturbed
1977	5355	318	0	5037	5.94		
1978	8785	592	0	8193	6.74	274	3430
1979	9105	636	0	8469	6.99	44	320
1980	9589	669	0	8920	6.98	33	484
1981	9705	765	0	8940	7.88	96	116
1982	10070	851	0	9219	8.45	86	365
1983	10239	925	0	9314	9.03	74	169
1984	9965	1004	0	8961	10.07	79	-274
1985	10315	1071	0	9244	10.39	67	350
1986	10983	1075	0	9908	9.79	4	668
1987	10450	2410	0	8040	23.06	1335	-534
1988	11804	2438	0	9366	20.65	28	1354
1989	12342	2445	0	9898	19.81	7	539
1990	13440	2523	0	10918	18.77	78	1098
1991	14108	2612	0	11496	18.51	89	668
1992	15015	2812	0	12203	18.73	201	907
1993	16426	2907	0	13519	17.70	95	1411
1994	16752	3186	0	13566	19.02	279	326
1995	17643	3464	0	14179	19.63	278	891
1996	18152	3733	0	14419	20.57	269	509
1997	19965	3918	0	16047	19.62	185	1813
1998	21517	4268	0	17249	19.83	350	1552
1999	23535	4551	0	18984	19.34	284	2018
2000	28097	4755	0	23342	16.92	204	4562
2001	30049	4929	0	25120	16.40	174	1952
2002	32109	5267	0	26842	16.40	338	2060
2003	33180	5592	0	27589	16.85	325	1072
2004	35744	5878	0	29867	16.44	286	2564
2005	42353	6273	0	36080	14.81	396	6609
2006	47317	6498	0	40819	13.73	225	4964
2007	53011	6581	0	46434	12.54	137	5614
2008	60234	6687	104	53547	11.10	51	7303

Source: AENV 2010.

Reclaimed land falls into three categories (AENV 2010). Land certified as reclaimed meets stringent requirements; it may be returned to the Crown as public land or remain with industry to manage access. A small amount of land, especially the plant site areas, may be private land. Permanently reclaimed land has undergone soil replacement, recontouring, and revegetation; lands are monitored and the company can apply for reclamation certification when the site meets the certification requirements. Temporarily reclaimed land is revegetated to grasses for stabilization and erosion control

and will undergo permanent reclamation at a later date.

Numerous reasons are given for lack of application for certification. Oil sands mining takes place on large temporal and spatial scales. Mining landforms are constructed over decades, with progressive reclamation occurring as areas become available. Land that is mined and reclaimed may be needed for storing materials, future operations, or access. Thus companies will not apply for certification until they are certain the land is no longer in use and has been fully reclaimed. While an oil sands operation is active, mining engineers have primary say in what happens on the lease for logistical operations.

When lands are certified after oil sands mining, reclamation liability transfers to the Crown. Thus the Government of Alberta has taken a cautious approach, relying on assurance monitoring for reclaimed areas rather than encouraging formal certification (AENV 2010). The Government is interested in certifying whole landforms, not small pieces, because it believes this provides a multidisciplinary approach to certification (watershed, soils, topography, succession, wildlife, diversity). This policy means waiting until monitoring and trend data are available for the youngest reclamation area on any landform. The Cumulative Environmental Management Association (CEMA), a not-for-profit, non-governmental organization, is working on standard procedures for monitoring forested lands to provide standardized data relevant to monitoring assurance and certification applications. The Government of Alberta is considering implementing tighter timelines for reclamation of in situ oil sands operations.

Several advantages for early reclamation have been articulated. Reclamation of mine closure facilities long after mining can be more expensive than during mining (Sawatsky et al. 2000). Progressive reclamation sets the stages for self-sustaining ecosystems early on and allows operators and regulators to acquire a longer performance record of reclaimed lands. Companies can discover problems while the mine is in operation instead of after closure when problems may leave public liabilities. Some progress is being made towards progressive reclamation and reduction of disturbed areas. For example, in 2002 True North Energy voluntarily committed to a progressive reclamation target, capping disturbance at 4000 ha; the Alberta Energy and Utilities Board targeted a 5000 ha cap for the project (AEUB 2002).

Concerns abound that development is rapidly outpacing reclamation abilities and activities, creating long reclamation lag times. Consequently, many advocate a total disturbance area cap for each project, and for the oil sands in general, to ensure reclamation occurs in pace with development. To date, neither government nor industry has shown any interest in adopting a disturbance cap. There is further concern with the potential inability for cumulative effects to be understood and addressed, notwithstanding the extensive and comprehensive EIA done for each individual mining project and for large in situ projects. There is concern that if industry is allowed to continue to develop at the current pace, the potential for major negative cumulative effects increases dramatically.

Although close to 7,000 ha are reported as reclaimed, this number is self-reported by industry and remains questionable to the public. The estimate is also based on varying interpretations of what constitutes a reclaimed landscape. Thus there is a critical need for the oil sands industry and regulators to address the state of reclamation versus disturbance in the oil sands in a manner that is transparent and evidence-based.

9.3.2 One Reclamation Certificate

On March 19, 2008, Syncrude Canada Ltd. received a reclamation certificate for 104 ha of land known as Gateway Hill, approximately 35 km north of Fort McMurray. Syncrude applied for a reclamation certificate in 2003. In March 2004, after Alberta Sustainable Resource Development (SRD) and AENV completed a technical review, Syncrude was required to provide more information. AENV asked for additional information on the depth of reclamation cover materials, wildlife habitat use, and drainage volumes for runoff. SRD asked for a survey plan to delineate reclaimed land from mining areas.

Although a reclamation certificate indicated equivalent land capability, by regulatory definition, had been achieved, some non-industry and non-regulatory stakeholders were concerned that appropriate evaluation had not taken place. Disagreement with granting the reclamation certificate was associated with the fact that prior to mining the area had low-lying wetlands, whereas it was reclaimed to uplands. Hence, equivalent land capability was not considered to have been achieved. Gateway Hill did not contain tailings materials, and thus was not viewed as an example of the ability to reclaim tailings, thereby diminishing its significance to these same stakeholders as a demonstration of reclamation.

9.4 Current Levels of Performance

9.4.1 Steps and Challenges in Reclamation

Open pit mining of oil sands creates large, intense disturbances. Prior to mining, rivers and streams are diverted, merchantable timber is harvested and the rest is piled and burned or buried. Wetlands are drained and excavated. Topsoil is salvaged; overburden is removed and stored in overburden dumps or mined-out pits and some is used to construct large dykes for tailings. Large processing facilities and other infrastructures are established. During oil sands processing, sulphur and coke by-products are produced and stored on site (Section 4.5). Land reclamation has several steps including overburden levelling, recontouring, soil replacement or construction, revegetation, and land management. General descriptions of various materials below are compiled from multiple research and industry documents to provide a general understanding of reclamation challenges and potential.

As overburden is removed during mining, geological layers, including glacial and recent sediments, are mixed and cannot be reconstructed. There is an inevitable increase in volume with backfilling, making recontouring and levelling of the final landscape a challenge. Subsoil permeability increases once bitumen has been extracted from the sand, affecting groundwater flow, direction, and quality, and because groundwater has not been fully recharged, the water table will rise and/or fall.

After overburden levelling to achieve a desired topography, reconstructed landforms are covered or capped. Materials requiring capping or management are saline sodic overburden and tailings sand, which occupy more than two thirds of the mined landscapes, and coke and sulphur by-products. Reclamation covers are considered primary land capability controllers, to support establishment of boreal forest ecosystems, including uplands and wetlands, while minimizing detrimental effects of salts released from underlying overburden material into the root zone. Prescriptions vary with what is being covered and amounts and kinds of available cover material. A 1 m cover is required for landforms such as overburden dumps because of high salt content. Soil covers must meet LCCS criteria, and must

make optimal use of limited material. Development of optimal prescriptions, including appropriate depths, layering, and composition, is critical for reclamation and to reduce post-reclamation liability.

Overburden occurs above mined oil sands at a mean depth over 20 m (1 to >70 m). Texture varies from sandy loam to clay loam to sandy clay loam; oil content is usually < 2%, but could be as high as 6%. Saline sodic overburden is most common, is comprised of clay shales of silty clay to clay texture, and is moderately alkaline at pH around 7.8 to >8. It is a source of calcium and magnesium, but is low in trace elements. Overburden has moderate water retention and high saturated hydraulic conductivity; therefore, leaching can occur. Specific physical and chemical properties vary with type of overburden, which in turn affect its suitability for a plant growth medium and its effect on groundwater chemistry.

Tailings sand, a final product of bitumen removal, is medium to fine sand with a total sand content >90%. Materials differ in available water holding capacity and nutrient availability. Since the 1990s a non-segregating tailings has been created by adding gypsum. These consolidated (composite) tailings are loamy sand (80–85% sand), with 10–30% water content, 42% base saturation, 7.8–8.5 pH, 1.4–4.6 dS / m electrical conductivity, and 8–40 sodium adsorption ratio. Their release waters vary in salt, boron, fluoride, aluminum, and copper content. Reclamation requires elimination or transformation of liquid waste in holding ponds to create trafficable areas. Concern has been expressed that companies will deal with tailings containment areas by transferring tailings to other ponds and infilling the pond requiring reclamation, thereby only deferring the regulatory requirement for permanent management.

Overburden and tailings sand can be covered with fine textured material plus a peat-mineral mix cap, or a peat:mineral mix cap alone. Cover material is generally peat-mineral mix salvaged from pre-mined areas and stored in a stockpile or directly placed. Cover material is obtained by over-stripping peat into mineral soil, or rotovating peat into underlying mineral material, creating a mineral soil with < 17% organic carbon by weight, with a sandy loam to sand texture. Direct placement material is soil or surficial geologic material from a natural deposit placed directly on tailings sand or overburden; it includes sand and clay textured upland and lowland materials with variable organic matter. If sufficient peat-mineral mix or direct placement material is unavailable, sand or clay soil is used for cover.

Secondary material is suitable upland soil or surficial geologic material salvaged to a depth considered suitable for plant growth. It is salvaged and placed over tailings sand or saline sodic overburden. Secondary material can form the topsoil or surface layer, or a peat mix cap can be placed on the surface of the secondary material. Texture is usually sandy clay loam to clay loam. Secondary material is screened prior to salvaging for hydrocarbons, pH, sodium adsorption ratio, and clay content.

Various amendments have been used to modify the negative physical and chemical properties of reclamation materials. These are addressed in section 9.4.4.1 from a vegetation response perspective, since most amendments are added to make the materials more hospitable for plant growth and development or to enhance plant species composition.

Undisturbed soils in the oil sands region are mainly orthic gray luvisols, organic and organic cryosols, with some brunisols and gleysols. Land capability is class 3 to 7, indicating moderate to low capability. Soil characteristics are homogenized after mining and reclamation, although adding amendments increases that heterogeneity. Removing the heterogeneity of the reclaimed soils also removes

microtopographic variability and its inherent chemical, physical, and biological properties, which in turn reduces the variability of the developing habitat complex. Thus, soils of the reclaimed landscapes are considerably different from what was there before mining. This lack of, or reduction in, heterogeneity could have consequences for biodiversity since patchiness is an inherent requirement of biological diversity for both flora and fauna. Current studies of micro and meso site heterogeneity and their effects on floral and faunal colonization are underway.

Prior to mining upland boreal forest has aspen-dominated, aspen and spruce mixed-wood, and spruce-dominated stands of fair to medium productivity. Lowland boreal forest or muskeg dominated by black spruce and tamarack is classified as unmerchantable timber. Revegetation consists of planting desired marketable species. Relatively little management of reclaimed sites has been implemented. CEMA recently released updated Guidelines for Reclamation to Forest Vegetation in the Athabasca Oil Sands Region. The guidelines task force chair indicated the goal was to have local native plant communities to satisfy end land uses, which could be wildlife habitat, commercial forestry, or traditional land use.

For the 80% of Alberta oil sands buried too deep for open pit mining, in situ recovery techniques are used (e.g., steam assisted gravity drainage). In situ technologies disturb less land per unit of production than surface mining, but the spatial footprint is more dispersed, increasing landscape fragmentation, and requires more natural gas which increases land use due to gas production (Jordaan et al. 2009). Using a life cycle perspective, the land area influenced by in situ technology is comparable to that disturbed by surface mining when fragmentation and upstream natural gas production are considered. Little reclamation research has focused on in situ operations, thus data are not available for this report. Reclamation requirements and outcomes for in situ operations are expected to be similar to those required for conventional oil and gas disturbances, considerably less challenging than for mined sites.

Remediation, as it relates to environmental contaminant clean up, is addressed in a separate section of EPEA. Remediation is normally done before reclamation when required and must meet regulatory requirements. Remediation certificates may be applied for; receiving a reclamation certificate does not eliminate remediation liability. The research reviewed in the following sections did not address remediation in the oil sands as very little has been documented outside of tailings ponds remediation. Remediation guidelines or criteria will need to be specifically developed for oil sands operations.

9.4.2 Reclamation Achievement Determination from Research

Oil sands companies have supported graduate students and research programs for decades. Syncrude Canada Ltd. and Suncor Energy Inc. have conducted reclamation research since the 1970s. Thus there is a plethora of information on oil sands reclamation spanning several decades. Some information is in published peer-reviewed literature, but much is embedded in annual research reports and graduate student theses and dissertations. Because only one oil sands mined area has been certified as reclaimed, post-mining reclamation must be addressed via this body of research, as it is readily available and data were collected by third parties. Much of the current work is not readily accessible as dissertations, theses, and research papers are being written. Not all research and demonstration work has been cited because of temporal and spatial considerations in developing this report. However, citations are sufficiently representative of the work to grasp its magnitude, breadth, and significance.

Research focused on prescriptions and materials common at the time and thus is not always directly applicable to new prescriptions and technologies. Inconsistencies in research design and reporting detail mean it is not always possible to make direct comparisons between studies or draw conclusions. Studies are generally of short-duration and done early in a reclamation cycle, thus a final trajectory is unknown. However, repeated trends, trajectories, and issues, and general scientific interpretations and principles can be identified, and a realistic expectation for reclamation potential can be elucidated.

Assessing how rapidly a site is progressing towards its intended reclamation goal is currently hindered by lack of research on reclamation trajectories over time. Most reclamation research spans two to five years, the time of an MSc or PhD research program. Longer term research is often not supported because materials and methods used for reclamation of research sites may no longer be the standard for site construction after mining, or may be associated with a small area of land to be reclaimed and a small volume of material to be used. The scale of research plots may be considered too small for long term monitoring, requiring scaling up to field based site construction and reclamation. However, valuable data on reclamation trajectories can be gleaned from this research and should be supported.

The following summaries of research in sections 9.4.3 through 9.4.6 are based on numerous field, greenhouse, and laboratory research projects over several decades. Work published in peer reviewed journals and in graduate student theses and dissertations has been relied on most heavily. Research from the gray literature has been used sparingly and mainly in the revegetation section to illustrate similar trends to that in more scientifically reliable documents. Study details vary including location, substrates, spatial and temporal replication and scales, and weather conditions; these details are not presented with each citation in the interest of keeping this document to a reasonable size. However, all summaries are based on the full body of work, with a non-statistical, meta-analytical approach that accepts the inherent variability of reclamation materials, sites, and time frames.

Most sections contain general overall statements followed by summaries of specific studies that were used to develop the overall statement. A statement of “no impact” or “no effect” means there was no statistically significant positive or negative effect on the measured response variables.

9.4.3 Soil and Substrate Reclamation

9.4.3.1 Physical Properties

Soil physical properties at reclaimed sites changed little 5 to 20 years after reclamation and were similar to those of undisturbed soils of the area. Similar results were obtained for all reclamation prescriptions, with peat mixes at the surface of reclamation profiles improving soil physical properties compared to undisturbed soils. Thicker covers reduced soil water stress risk, with 35 cm covers posing some water limitations to vegetation; >50 cm covers provided sufficient water for plants. The higher risk associated with 35 cm covers means a site could shift to a xeric to subxeric ecosystem. Layering fine over coarse textured materials increased soil water in the root zone. Some reclamation uncertainly was associated with hydrologic properties and salt movement in the root zone and groundwater.

Soil structure, a key indicator of soil capability, regulates air, water, and nutrient movement, affecting rooting and micro-faunal and meso-faunal activities. No soil structural limitations were found in

reclaimed soils compared to undisturbed soils (Yarmuch 2003; Meiers 2002). Saturated hydraulic conductivity, the ability of soil to transmit water, of reclaimed soils increased rapidly for three to five years, then stabilized (Yarmuch 2003; Meiers 2002). Capping depth did not affect physical property changes over time for any capping materials; it did affect hydraulic conductivity of shale underlying 35 and 50 cm covers, but not 100 cm covers (Meiers 2002). Freeze-thaw and wet-dry cycles were thought to facilitate weathering of clay shales under shallow covers (Meiers 2002). Reconstructed soils had saturated hydraulic conductivities similar to undisturbed soils and a peat mix at the surface increased values (Yarmuch 2003), emphasizing importance of these measured values in calibrating numerical models of water dynamics within covers (Shurniak 2003). Bulk density, soil penetration resistance, and infiltration of 13-year-old reclaimed and undisturbed soils were equivalent (Macyk et al. 2004).

Since water holding capacity indicates ability of a soil to store and release water for plants, wetlands, water courses, and salt flushing, it ultimately affects long-term sustainability of the landscape. LCCS considers available water holding capacity the primary controlling factor in the overall capability rating. Reclaimed soils had higher available water holding capacities than coarse textured undisturbed soils and lower values than fine textured undisturbed soils.

Tailings sands had higher available water holding capacity than undisturbed soils with higher silt and clay content (Macyk and Turchenek 1995). Increased peat:mineral mix over tailings sand increased total soil water (Moskal 1999). Available soil water was quantified by various methods (Leatherdale 2008; Burgers 2005; Macyk et al. 2004; Boese 2004; Chaikowsky 2003; Shurniak 2003; Moskal 1999). Materials and layering created textural breaks affecting soil water content; water draining from coarse cover material into fine substrate material ponded on the substrate (Chaikowsky 2003). Water retention was enhanced by sandy clay loam to clay loam soil caps over tailings sand (Burgers 2005) and layering peat mineral mixes over tailings sand doubled soil water (Moskal 1999). Long-term monitoring showed water accumulation above a secondary tailings sand interface in all profiles (Macyk et al. 2004). Covers dried during prolonged dry cycles, potentially limiting soil water (Boese 2004). Decreases in water content of shale overburden showed water was drawn from the shale to satisfy water demands in the covers. In tailings sands systems, roots can extend beyond the soil cap and utilize water stored there (Macyk 2002). Field soil water characteristic curves indicated tailings sands provided an available water holding capacity of about 1.0 mm of water per cm of tailings sand.

Significantly lower soil water and a 5 °C higher soil temperature occurred in a reclamation area with LFH placed at the surface compared to LFH of an undisturbed ecosite (McMillan 2005). Combined influences of the plant community on soil water, and how water balances evolve with the plant community are being further investigated. A 60–80 cm monolayer soil cap over tailings sand supported a seven-year-old forest stand, with excess soil water for deep percolation and salt flushing (Burgers 2005; Chaikowsky 2003). After 13 years, 30–50% of soil profiles had water available to move through the cap into tailings sand, flushing salts while satisfying vegetation water demand (Macyk et al. 2004).

Numerous models have been developed to evaluate relative performance of alternative cover designs (Shurniak 2003). A peat mix cover over secondary materials with a 60 cm minimum depth performed best. The ability of soil covers to provide adequate water to plants was evaluated through a series of climate cycles over the last 60 years, suggesting 100 cm layered covers had a low probability of not

being able to supply adequate available water; the 50 cm layered cover performed similarly, the 35 cm cover lagged substantially (Elshorbagy et al. 2007).

A field calibrated water balance model and available historical meteorological records have been used to estimate maximum soil water deficit a soil cover can sustain over the growing season (Elshorbagy et al. 2007; Elshorbagy et al. 2005). The probabilistic approach accounted for physical variability like layering and climatic conditions and uncertainty in model structure and model parameters. To assess sustainability of soil cover alternatives, a generic system dynamic watershed model was used with historical meteorological records to estimate maximum soil water deficit and annual evapotranspiration fluxes (Kesha et al. 2010). The reconstructed watershed provided less water for evapotranspiration than undisturbed systems initially but then adapted to vegetation type. Long term simulations of another model showed store-and-release ability of reconstructed watersheds was satisfactory and capable of responding to higher water demands with mature vegetation because it had a surface peat mineral mix surface layer with high saturation hydraulic conductivity that allowed more infiltration and less runoff from a precipitation event (Lakshminarayanarao 2008).

The hydrogeology of South Bison Hill, made of reclaimed material from saline-sodic clay shale was investigated (Chapman 2008). Hydraulic conductivity of different zones in the hill was measured with slug tests and a steady state groundwater flow model was developed. Hydraulic conductivities were higher than that of the undisturbed formation, indicating excavating the formation and building the hill enhanced hydraulic conductivity. The groundwater flow system is expected to develop in South Bison Hill, contrary to the previous assumption that, because of low hydraulic conductivity of the formation, only small independent perched groundwater systems at the surface of reclaimed hills would develop. This work is the only publicly available study of reclaimed hill hydrogeology and further work is required to better understand groundwater flow system development in reclaimed piles.

9.4.3.2 Chemical Properties

Soil chemical properties of reclaimed soils are directly related to the materials and amendments used to construct the soil profiles in reclamation. Unlike soil physical properties, there are often significant differences in soil chemical properties among reclaimed and undisturbed soils, although these changes are often ameliorated with time. Tailings sands are placed using recycled tailings water which contains elevated salt concentrations from salt ore bodies (Price 2005). These salts are mainly sodium, chloride, and sulphate, with increasing calcium from composite tailings (Price 2005), and are hereafter referred to generically as salts, mainly referring to those undesirable in high concentrations for most plant species. When oil sands are slurried with water during extraction, these salts are washed into the tailings water stream which is continually reused (Price 2005). Salt transfer from saline sodic overburden or tailings sand into the root zone is the biggest soil chemical issue in oil sands reclamation. Mobile salts in overburden and lack of salts in cover material can result in upward diffusion of salts into the cover material. This movement of salts, with subsequent salinization and sodification of reclamation soils, occurred particularly under high water table conditions, at toes of slopes, and tipped benches of tailings dykes.

Salts are expected to be flushed from reclamation covers via deep percolation and interflow in

reclamation profiles. Where the water table was deeper than 2 m, in recharge areas with sufficient topographic relief or drainage, salts in tailings sands were flushed within five years (Burgers 2005; Price 2005; Macyk et al. 2004; Chaikowsky 2003). Preferential flow was associated with large immobile regions and high rates of mass transfer, indicating a large interaction with soil solutes such that salt flushing may be aided by preferential flow (Welter 2009). Deep groundwater flow systems are expected to carry flushed salts to discharge areas where they can be managed over several hundred years, or washed away into river systems. Under the worst case scenario of low deep percolation (2 mm/yr), salinity would persist up to 50 years before soil profile flushing would be measurable. Slope toes and discharge areas, without deep percolation and interflow, were predicted to have ongoing salinity increases, with salts washed from uplands moving into receiving streams and wetlands. Consequently, maintaining the water table below 2 m to decouple groundwater and cover soil systems, and incorporating topographic relief into tailings sands landscapes, would be needed for local and regional groundwater flow systems to develop. If the water table is maintained above 2 m, salts may inundate the cover or be drawn up from a saline water table, particularly during long drought periods.

Where salts are transported through reclamation covers, such as at toe slopes, sodification may occur and persist, deteriorating soil quality (Macyk et al. 2004). When clay soils are subjected to sodium-rich water, sodium exchanges with calcium on clay surfaces and is held there, preventing flushing. Sodium dominated soils have poor structure due to aggregation and dispersion of sodium dominated clays, resulting in shrinking and swelling, which limits air and water movement and plant root development. Dispersed horizons can shrink and swell during wetting and drying, negatively affecting plant roots. If salt ingress is isolated to lower subsoils, sufficient calcium in the secondary layer may counteract sodification if flushing is induced (Macyk et al. 2004). Sodicity will not likely improve as rapidly as salinity and soils in discharge areas have received a 2 class LCCS capability loss due to sodification over eight years (Macyk et al. 2004). Thus guidelines established for soil suitability stipulated suitable salinity and sodicity levels (Macyk et al. 1993).

Diverse, productive boreal upland, riparian, and wetland communities exist on subsoil materials much more saline and sodic than thought possible. Although undisturbed boreal forest communities showed some species use saline water, especially under drought conditions, salinity and sodicity in soils influenced plant growth and community composition (Close 2007; Purdy et al. 2005; Sinha 2003; Croser et al. 2001; Franklin et al. 2001; Renault et al. 1999; Bertness 1991; Greenway and Munns 1980). Within species genotypes, response to salts varied (Khasa et al. 2002; Renault et al. 1998).

Saline tailings water influenced plant water relations similar to drought by creating a soil osmotic gradient that made it difficult for plant roots to get water; at elevated concentrations, sodium and chloride were more toxic than magnesium and sulfate (Renault et al. 2001) with chloride a major factor in seedling injury (Apostol et al. 2002; Franklin et al. 2002; Redfield and Zwiazek 2002). Significant salinity and/or sodicity were absent in most reclaimed upland soils and did not reach biologically significant levels in any study areas (Burgers 2005; Macyk et al. 2004; Chaikowsky 2003). Relatively low and high vegetation canopy cover on a tailings storage facility were attributed to soil organic matter and micronutrient variability, rather than to salinity or sodicity (Burgers 2005). Riparian and wetland areas, however, had rising salinity over time (Macyk et al. 2004). Some wetland and upland

species bioaccumulated boron and sodium when irrigated with tailings water (Macyk et al. 2004).

Soil pH in reclaimed soils generally ranged from slightly below to slightly above 7, with the desired range from 5–7. In most cases, the pH of reclaimed soils was higher than of undisturbed soils of the region, attributed to high pH parent material used in capping (Rowland et al. 2009; Mackenzie 2006; Burgers 2005; Macyk et al. 2004; Lanoue 2003). Fibric peat mixes, with the lowest nitrogen mineralization rates, had significantly lower pH than other peat mix types (Hemstock 2008). Adjacent naturally saline areas with high subsoil pHs (8.5–9.0 at 20–50 cm), the high pH of consolidated tailings water contributed to leaf chlorosis and reduced growth (Renault et al. 2001).

9.4.3.3 Organic Matter

Soil organic matter is a primary constituent of soil quality, controlling water storage and release and providing nutrients for plant and ecosystem development. Since organic matter development takes decades to centuries, proper placement is important in reclamation and a key indicator of reclamation success. Salvage and replacement of organic matter in reclaimed uplands is governed by the Soil Quality Criteria (Macyk et al. 1993) and LCCS (CEMA 2006), which stipulate topsoil (0–20 cm) should contain at least 2%, but no more than 17% organic carbon. Organic carbon is considered a surrogate for organic matter for most soil reconstruction materials derived from undisturbed soils but is not appropriate for hydrocarbon dominated materials such as coke and lean oil sands, if used as reclamation substrate materials (currently under investigation). The range of organic carbon content considered suitable is the amount necessary to provide a suitable root zone but not so much that without a mineral component would lead to excessive drying and high insulation.

Organic matter quality can be described by its relative degree of humification or decomposition. More highly decomposed materials are of higher quality. Forest floor, L, F, and H layers represent varying degrees of organic matter decomposition, with L being the leaf layer or poorly decomposed materials, F the fibric layer or partially decomposed organic matter, and H the humic layer or completely decomposed organic matter. Where peat mixes are used as an organic amendment, they are classified by degree of decomposition, ranging from fibric (least decomposed) through mesic to humic. The peat source, sedge versus moss, also influences its degradability and nutrient release capability.

Organic carbon in topsoils constructed with various reclamation materials, including peat mix, secondary materials, direct placement mineral materials, and LFH, exceeded those in undisturbed upland soils (Turcotte et al. 2009; Mackenzie 2006). Total carbon to 1 m had been replaced, but its distribution varied with subsoil materials (Macyk et al. 2004; Lanoue 2003), potentially impacting nutrient and water availability.

9.4.3.4 Nutrient Cycling

Nitrogen release rates in reclaimed soils varied with organic matter type, soil temperature, and soil water, which influenced microbial activity (Lanoue 2003). Nitrogen mineralization rates of LFH and peat mix treatments were similar to undisturbed forest LFH in one study (McMillan 2005); in another study, reclamation materials, regardless of soil organic matter quality, had low nitrogen mineralization relative to forest floors (Hemstock 2008). Woody debris treatments had lower soil nitrogen, suggesting

nitrogen immobilization (Brown 2010). Other indicators of nitrogen availability, including dissolved organic nitrogen, dissolved organic carbon, and extractable ammonium were higher in natural LFH than in reclamation treatments, with no differences among treatments. Whether selective salvage and placement of specific peat types will alter nitrogen supply in reclaimed soils is not currently clear.

Available nitrogen in reconstructed cover soils and coarse textured undisturbed soils were similar, but considerably less than in undisturbed fine textured soils (Mackenzie 2006; Lanoue 2003). Available nitrogen was considered insufficient for ecosites on fine textured soils regardless of soil amendments, potentially necessitating use of nitrogen fixing plants or fertilizer. Total nitrogen in 0–20 cm of soils reconstructed with peat mixes or LFH equalled or exceeded that in undisturbed fine textured soils.

Forest ecosystem model outputs indicated that, given predicted and measured nitrogen release rates for peat mix caps, 20 cm peat mix caps would result in 40–70% less tree production than undisturbed sites (O'Kane 2006). Adding up to 50 cm of peat mix cap improved productivity, but not equivalent to undisturbed ecosites. Nitrogen is required in the top 20 cm, where most rooting and nutrient cycling occurs, and if supplied from current atmospheric deposition, by nitrogen fixing plants, fertilizer or other methods, merchantable timber volume was projected to equal regional estimates.

Total phosphorous was replaced with peat mix or fine textured mineral soil in the upper 20 cm of reconstructed soils (Lanoue 2003). LFH treatments had greater available phosphorus than peat mineral mix treatments(Mackenzie and Naeth 2007; Mackenzie 2006). Woody debris treatments had higher soil phosphorus suggesting leaching from wood (Brown 2010). Large available phosphorus pools in 20 to 100 cm depths of undisturbed ecosites were not replaced with any reclamation prescription, but were replaced if soil material from the upper 1 m of undisturbed soil was selectively salvaged and used in the soil cover. Amendment with phosphorus fertilizer was not considered an alternative to appropriate salvage and replacement of coarse and fine textured surface horizons (Lanoue 2003). Without adequate amounts or forms of iron or aluminum in tailings sand or deep salvaged natural sands to retain soluble forms of phosphorus beyond those used by plants, phosphorus applied as soluble phosphate fertilizer was predicted to leach beyond the root zone in young systems, with serious implications to down stream receiving systems. Application of rock phosphate was suggested, but the high pH of tailings sands systems and expected time frame for its amelioration (50–200 years) poses a serious constraint to timely release of this nutrient (Lanoue 2003).

LFH treatments had greater concentrations of available soluble potassium compared to peat mineral mix (Mackenzie and Naeth 2007; Mackenzie 2006). Poor vegetation cover on clay loam secondary caps was partially attributed to low potassium, copper, manganese, and zinc, although concentrations of these elements considered toxic or required is not known for most native plant species; on peat mineral mix high vegetation cover was correlated to higher micronutrients (Burgers 2005). Numerous other elements are essential to plant growth and function, but little research has been conducted to determine sufficient or deficient soil concentrations. Micronutrient concentrations varied with soil type, being highest in organic layers or peat mixes. Manganese and zinc in peat mix and direct placement top soils were lower than in undisturbed soils, while boron was higher, often exceeding CCME soil quality criteria. Reconstructed and undisturbed subsoils had similar concentrations, although differences were reported for undisturbed coarse textured sites.

Tissue analyses from reclaimed and natural sites were inconclusive as studies reported opposite trends for tree tissue nutrients (Kelln et al. 2009; Macyk et al. 2004). Boron was higher in trees on peat mixes than on controls or on clay loam secondary materials. Sodium was elevated in plant tissue in contact with sodium rich materials, such as seepage water (Macyk et al. 2004) or saline sodic overburden (Kelln et al. 2009). After treatment with tailings water with added mineral nutrients, tree shoots had significantly elevated concentrations of sodium, chloride, sulphur, phosphorus, boron, and strontium and significantly reduced iron, molybdenum, barium, and potassium (Franklin et al. 2002).

9.4.3.5 Soil Organisms

Establishing functioning ecosystems via reclamation requires critical processes carried out by communities of soil organisms. Measurement of soil organism diversity and function may be one way to determine if a reconstructed system is on a trajectory towards recovery. All reclamation soils supported functioning communities of organisms, although communities varied with disturbance, amendments, and time, typical of newly evolving ecosystems.

Microbial diversity was similar in topsoil from both reclaimed and undisturbed sites in one study (Macyk et al. 2004), although in another study, microbial biomass carbon and nitrogen were lower in reclaimed soils than in undisturbed forest soils, with microbial biomass nitrogen and respiration positively correlated to soil water (McMillan et al. 2007; McMillan 2005). Microbial activity may be limited by water in reclaimed soils in early years due to differences between reconstructed soils with no tree cover, and shady natural forests (McMillan 2005). Mycorrhizal populations were lower in peat mix and secondary material than in undisturbed soils; the dominance of younger reclamation soils by arbuscular mycorrhizae was attributed to early successional plant species (Bois et al. 2005). Total microbial biomass and soil basal respiration increased with time since reclamation (Macyk et al. 2004; Mensforth 1984). Phosphorus fertilizer enhanced mycorrhizae development (Danielson et al. 1983a); high nitrogen suppressed microbial activity and decomposition and mycorrhizal infection in tailings sand-peat-clay mixes (Parkinson 1984).

Microbial communities were related to water and temperature differences associated with amendments (Hemstock 2008). Total microbial biomass and soil basal respiration were greatest in muskeg peat over tailings sand (Mensforth 1984); vesicular arbuscular mycorrhizae were greatest in peat over tailings sand and muskeg peat mixed with tailings sand and poorest in unamended tailings sand (Parkinson 1984; Danielson et al. 1982). Microbial biomass carbon was lowest in peat mix caps, similar in LFH caps and undisturbed soils, and highest in stockpiled peat and peat from undisturbed bogs (Macyk et al. 2004). Mycorrhizae isolated from salt impacted reclamation areas had a higher salt tolerance than those from boreal forests, indicating that the mycorrhizal community can respond to soil conditions and that saline areas can have functioning mycorrhizal communities (Bois et al. 2005).

Although differences were small, highest microbial diversity was found on undisturbed sites with LFH horizons and reconstructed areas with replaced LFH (Macyk et al. 2004). Even unamended overburden and sand tailings had some microbial diversity, indicating soil microorganisms were widely present and/or distributed throughout undisturbed and reclamation areas. Reclamation treatments with LFH had higher respiration rates, microbial biomass carbon, and microbial biomass nitrogen than peat

mineral mix, indicating LFH may stimulate microbial activity compared to peat alone (McMillan et al. 2007). Although soil under woody debris had lower temperature ranges and higher soil volumetric water than non woody debris soils, no microbial community differences were found (Brown 2010).

Peat, overburden, sewage sludge, and inorganic fertilizers were tested as potential sources for a diversity of mycorrhizal fungi. For most plant species, fresh peat was a superior inoculant with infection rates increasing over time (Visser et al. 1984a; Visser et al. 1984b). Stockpiled peat was a poor growth medium, due to elevated pH. Sewage sludge increased plant growth and microbial populations, but suppressed mycorrhizal fungi. Sewage sludge was the best amendment in a 10 year study (Danielson 1991). Overburden depth had no effect on mycorrhizal infection, but the amount of organic matter was important (Danielson et al. 1983a) and shallow overburden was a better source of mycorrhizal fungi then deep overburden (Danielson et al. 1982). Muskeg peat, shallow mineral overburden, and deep overburden had both ecto and vesicular arbuscular mycorrhizae (Danielson et al. 1983a). Mycorrhizal development was slow in peat but shallow overburdens became heavily mycorrhizal. Microbial respiration and biomass were highest in peat.

Carex and feather moss peat sources provided a variety of inoculum and enhanced plant growth on tailings (Kernaghan et al. 2002; Danielson et al. 1983b). Of the introduced inoculum investigated, E-Strain (*Complexipes*) repeatedly performed well, establishing and persisting for the duration of each study (Danielson and Visser 1989; Danielson and Visser 1988). Use of mycelial slurries was investigated (Danielson et al. 1984a; Danielson et al. 1984b). Infections occurred with peat but not sewage sludge additions (Zak and Parkinson 1983; Zak and Parkinson 1982).

Over time, mesofaunal (arthropod) population density increased in reclamation soils to levels similar to undisturbed forest systems. LFH accelerated this increase relative to peat mineral mixes. Mesofaunal community structure in reclaimed systems continued to differ from undisturbed sites after 34 years.

Use of ethidium monoazide bromide was a suitable method for detecting the large and varied microbial population inhabiting sulphur blocks which can influence block oxidation (Pisz 2008). Levels of microorganisms in the block varied, which may parallel the varied pockets of air and water collected in geomorphic fractures. There were heterotrophic and autotrophic sulphur oxidizing organisms present. Microbial communities residing in the sulphur block were partially responsible for sulphur oxidation.

9.4.4 Revegetation

Numerous plant species have been studied and evaluated in oil sands reclamation research for decades. Species names have been omitted from the summaries below, as the intent is to provide a general review of plant response, not a specific species response in oil sands reclamation. The names of many plants used in cited research are listed in Table A6.1 (Appendix A6) to document that revegetation research has been both broad and detailed. Similar studies did not always yield similar responses on an individual species basis; likely associated with seed and transplant stock quality, climate details for the growing seasons in the years of study, and substrate reclamation. Thus a careful attempt was made to discuss general supported trends in the sections below. In general, revegetation with desireable species was attainable. Although longer term plant community development has not been studied extensively over a sufficient period of time to conclusively state that plant communities are developing along

acceptable trajectories, early work and a few longer-term studies indicates this is the case.

9.4.4.1 Vegetation Response to Capping Materials and Amendments

As with most intense disturbances, amendments have been used in oil sands reclamation to enhance physical, chemical, and biological properties of tailings and overburden, facilitating plant establishment and growth. Properties of materials, alone and in combination, incorporation versus spreading, and amount of materials, impacted plant response in both positive and negative ways, as evidenced in the studies discussed below.

Germination and emergence were reduced and plant biomass and root growth were stunted on tailings sand due to chemical properties and/or crusting; amendment improved plant response (Grant et al. 1985; Techman Engineers Ltd. 1983; Schumacher and Bell 1980; Shopik and Cary 1977; Massey 1973). On mature fine tailings alone or mixed with fine tailings, native grasses, but not native forbs, performed well (Li and Fung 2001). Transplanted aquatic species performed well on 1 m but not 4 m of consolidated tailings (Paquin 2002). Consolidated tailings release water added to tailings reduced plant biomass due to increased sulphate and sodium, and high sodium was found in woody vegetation tissue (Golder Associates 1997). Greenhouse shrub survival improved more by adding consolidated tailings to capped tailings than to uncapped tailings sand (Renault and Zwiazek 1997; Renault and Zwiazek 1996). With or without a cap, conifers did not survive and shrubs were adversely affected in consolidated tailings and in fine tailings incorporated into tailings. Glacial till mixed with tailings sand did not improve plant growth (Turchenek and McGill 1976).

Herbaceous and woody plant growth were greater on overburden than on tailings sand (Dunsworth et al. 1979), with peat, straw, or wood fibre mulch having no effect on woody plant establishment or growth (Shopik 1983). Native grass and legume emergence was higher on overburden and tailings sand mixes than on tailings sand or tailings sand and oil sands mixes (Vaartnou and Sons Enterprises Ltd. 1978). Deep overburden was detrimental to plant growth as plants were low in nitrogen and phosphorus (Danielson et al. 1982). Fine textured overburden increased water holding capacity compared to coarse overburden, but mixing overburden and tailings sand did not affect hydraulic conductivity (Turchenek and McGill 1976). Overburden may act as a buffer, but can result in a quickly drying and hardening surface when silt cements sand particles together (Rowell 1979; Vaartnou and Sons Enterprises Ltd. 1978).

Oil sands alone or mixed with tailings sand was an adequate substrate for native and non-native grasses and legumes but growth was poor for all species (Takyi et al. 1977). Plant biomass decreased when lean oil sands (< 6% bitumen) were added to tailings; agronomic legumes performed better than native and agronomic grasses; native woody species had highest survival (Fedkenheuer 1980). Native and naturalized legumes did not establish on oil sands when wetted (Vaartnou and Sons Ltd. 1978).

Tailings sludge was a good source of slow release potassium, although nitrate and phosphate were low (Rowell 1980). Tailings sludge had a variable effect on plant growth, likely due to alteration of substrate pH. Tailings sludge with high bitumen inhibited germination and emergence. Plant growth was greater in sludge sand mixes than tailings sand; grasses performed significantly better than legumes (Johnson et al. 1993).

Adding fertilizer before or after seeding is common in reclamation. Research focused on optimum application rates and responses by different species; results were highly variable and separating the effects of fertilizer and other amendments which also supplied nutrients was difficult. Fertilizer generally increased native and non-native grass germination and biomass on tailings sand, overburden, and various reclamation soils (Russell Ecological Consultants 1982; Rowell 1979; Vaartnou and Sons Ltd. 1978; Takyi et al. 1977; Norwest Soil Research Ltd. 1976; Yamanaka 1976). Legumes and native species responded best to low rates of fertilizer (Dai et al. 1981; Vaartnou and Sons Ltd. 1978; Takyi et al. 1977). Various times of fertilizer application were assessed leading to different recommendations (Tuttle 1991, Alberta Forest Service 1980; Dunsworth et al. 1979; Rowell 1979; Fedkenheuer and Langevin 1978; Takyi et al. 1977; Fedkenheuer and Browne 1979). Today fertilizer application is a general treatment for most reclamation sites for a period of one to three years.

Lime added as a stabilizer or coagulant to prevent tailings sand and sludge from separating had no effect on plant growth on a tailings sand, peat, overburden mix (Grant et al. 1985; Johnson et al. 1983; Takyi et al. 1977). Without overburden, lime de-acidified peat, increasing nitrogen fixing plant establishment and plant shoot and root growth. At high application rates lime stabilized sand-sludge mixes in the short-term, but was not considered cost effective for large-scale operations.

Gypsum was added during or following oil sands processing as a coagulant in consolidated tailings formation and to reduce salinity (Renault et al. 1998; De Jong 1982; Syncrude 1978). Surface application was adequate but not as effective as incorporation, and increasing surface rates had no effect on percolation. Gypsum had no effect on most plant species, but was detrimental to some.

Sewage sludge is a source of plant nutrients and increases soil microbial biomass, organic matter, and water retention. Municipal sewage sludge was incorporated into tailings to enhance mycorrhizal fungi and plant growth (Visser et al. 1984c; Visser et al. 1984d). High application rates severely reduced root growth and survival of some plant species and inhibited mycorrhizal infection. No oil sands studies investigated the effects of sewage sludge on the physical or chemical properties of the soil, although research elsewhere indicated it may be a cost effective amendment to improve overall soil quality.

Mulch generally improved soil water retention, increasing seed germination and seedling establishment, stabilizing soil, and reducing soil and seed erosion, whether applied prior, during, or following seeding or planting. The most commonly used mulches in oil sands reclamation have been wood fibre, straw, and peat. Wood fibre and sphagnum were generally hydromulched with seed or added in water slurry after seeding (Dunsworth et al. 1979; Norwest Soil Research Ltd. 1976), but decreased plant density (Dai and Fedkenheuer 1978; McCoy et al. 1976; Lesko 1974). Straw mulch was applied prior to seeding or planting. Wood fibre mulch performed poorly (Johnson et al. 1993).

Peat mulch applied with seed assisted plant establishment on oil sands sludge by absorbing bitumen which inhibited germination; similar results were obtained with a 1 cm peat layer prior to broadcast seeding, followed by another 1 cm peat layer (Johnson et al. 1993). Adding peat with overburden to tailings sand increased plant growth by improving soil structure, water retention, and nutrient availability (Li and Fung 2001; Dunsworth et al. 1979; McGill et al. 1978; Selner and Thompson 1977; Takyi et al. 1977). The rate of organic matter loss in peat was slow, thus the beneficial effects on

tailings sand lasted longer (Rowell 1980). Surface application of peat, compared to peat and sand mixes, accelerated litter and root decomposition and increased nutrient cycling (Danielson et al. 1982). Acidic peat reduced nitrogen fixation by legumes, addressed through lime addition (Takyi et al. 1977). Incorporating peat enhanced plant growth and evened root distribution (Rowell 1979; Takyi et al. 1977). Increased peat increased the natural establishment of native species (AMEC Earth and Environmental Limited 2002) and provided greater nutrients, but suppressed iron and magnesium uptake, reducing root and shoot biomass (Danielson et al. 1983b). Reclamation covers with fibric peat had lower species richness and cover than those with mesic and humic peat, since fibric peat was less decomposed and more acidic, reducing the nitrogen mineralization rate and limiting plant growth (Hemstock 2008). When fresh and stockpiled peat was used as a source of native plant species, weedy non-native species dominated (Fedkenheuer and Heacock 1979).

Native plant species growing on coke in the greenhouse were limited due to poor water retention and soil structure (Naeth and Wilkinson 2002), although a current study is much more successful (Naeth in progress). The coke surface required daily watering to prevent drying; variable sized aggregates caused seed to lodge too deep for germination or prevented emergence. Barley growth in coke was similar to that in reclamation soil; however, mixing the two inhibited plant establishment (Wasylyshen 2002). In coke and peat-mineral mix, coke delayed germination for some monocots, increased root:shoot ratios, and reduced height, pigment content, transpiration, and stomatal conductance, indicating water stress (Nakata 2007). Nutrient deficiency was an issue. Capping versus no capping affected some parameters. Nickel, vanadium, boron, and molybdenum were often higher in coke-treated plants than controls.

Amending composite tailings and tailings sand with peat and pulp waste were best for hybrid poplars and conifers whereas agriboost and pulp waste and fly ash were worst (Khasa et al. 2005). Overall quality of seepage tailings water on a storage facility deteriorated over four years with increased electrical conductivities, sodium, and sodium adsorption ratios (Macyk and Faught 2001). Watering native vegetation with tailings water, altered plant tissue content of sodium, boron, and manganese.

9.4.4.2 LFH and Woody Debris for Revegetation

Commercial supplies of native boreal seed for grasses and forbs are limited with most of them being unavailable (Lanoue and Qualizza 2000). LFH of upland forests is a source of native propagules (seed, spores, vegetative parts). Stripping a thin layer from the surface for large scale operations was considered uneconomical in the past; however, research showing enhanced revegetation led to recent regulatory requirements for LFH salvage and use in reclamation.

LFH contained significantly more propagules and had higher diversity than peat (Mackenzie and Naeth 2007; Mackenzie 2006; AMEC Earth and Environmental 2002). LFH in reclamation caps significantly increased plant density, canopy cover, and species diversity relative to peat, particularly for native species. Most species in peat mineral mix were monocots compared to forbs and woody species in LFH. Peat application depth had little effect; LFH was more beneficial for plant establishment when applied at 20 cm versus 10 cm. Diversity was similar for both depths. Placement of LFH in summer rather than winter increased species richness and cover (Lanoue and Qualizza 2001), although the storage of the LFH over summer may have impacted results of that study. Research is ongoing on the

impact of LFH on plant community development, with promising results (Mackenzie and Naeth 2010; Mackenzie 2006). Since LFH is often available prior to reclamation areas being available, work is underway to determine long term viability of species in LFH stockpiles. Preliminary data indicate viability of most species is lost within a year (Mackenzie and Naeth in progress). The long-term impacts of LFH require further research and a new study to address this is currently in progress.

Woody debris affected vegetation cover and richness, woody species survival and abundance, microbial biomass carbon, mycorrhizal biomass, and soil nutrients, temperature, and water (Brown 2010). Woody debris increased species richness and decreased introduced species cover. Woody debris cover was positively associated with vegetation cover. More woody seedlings planted on woody debris treatments survived and woody debris cover was positively associated with woody plant abundance.

9.4.4.3 Revegetation Species Selection

Various recommendations on species to use in oil sands reclamation have been made over decades, most based on relatively small-scale and short-term research. The focus was originally on non-native species and a rapidly establishing vegetation cover. Agronomic grass and legume mixes were commonly used in greenhouse and field studies. That focus has shifted to native species and plant community development. Individual species recommendations were often inconsistent based on single studies as in the following examples. In general there is no concern regarding the ability of plants to establish, survive, and develop in oil sands reclamation.

Annual cover crops such as barley and oats are currently seeded as they do not inhibit woody seedlings, and winter stubble protects seedlings by capturing snow. Amendment of composite tailings with peat improved germination, survival, and growth of cover crops but did not prevent leaf injury (Renault et al. 2003). Ornamental grasses were considered as cover crops (Selner 1976).

Agronomic grass and legume species germinated and established on tailings sand and overburden and were generally enhanced by amendments; many were recommended for oil sands revegetation (Macyk 2002; Naeth and Wilkinson 2002; Crowe et al. 2001; Smreciu et al. 2001; Fung et al. 2000; Warner 2000; Naeth et al. 1999; Silva et al. 1998; Brendell-Young et al. 1997; Johnson et al. 1993; Klym 1982; Russell Ecological Consultants 1982; Tomm 1982; Fedkenheuer and Langevin 1978; Vaartnou and Sons Enterprises Ltd. 1978; Takyi et al. 1977; Yamanaka 1976; Lesko 1974). Native species germination was variable and lower than that of non-native species, although those that established had comparable cover and biomass. Not surprising, since this is typical of native versus non-native species in sites other than the oil sands. Performance varied with plant material age and source, seeding or planting time, exposure, soil water, and substrate. Some grasses produced good cover without affecting woody seedlings; others, particularly those with dense cover, suppressed seedlings (Fung et al. 2000; Fedkenheuer and Langevin 1978).

Some aquatic species were assessed for tailings ponds and other water saturated deposits (Crowe et al. 2002; Crowe et al. 2001; Golder Associates 1997; Renault and Zwiazek 1997). Oil sands effluent water inhibited their germination, although common cattail established from plugs and persisted in wetlands receiving oil sand processing effluent (Brendell-Young et al. 1997; Johnson et al. 1993).

In the past decade interest in poplar hybrids has grown (Fung 1991; Russell Ecological Consultants 1987; Dunsworth et al. 1979). Other non-native trees and shrubs were studied and performed well on oil sands reclamation sites (Blackmore 1982; Dunsworth et al. 1979; AENV 1972). Native woody species have been more widely researched than native herbaceous species as agronomic species of the latter are readily available and less costly than natives (Geographic Dynamics Corp. 2002).

For a long time a focus of oil sands revegetation was on testing and development of saline tolerant species (Yi et al. 2008; Renault et al. 2004; Franklin 2002). Naturally saline boreal communities were assessed as models for reclamation of saline oil sand tailings (Purdy et al. 2005). Plant communities in strongly saline landscapes were quite different from non-saline boreal landscapes and were dominated by halophytes common to saline habitats of the Great Plains. Forest vegetation established over saline soils as long as the salts were below the rooting zone, suggesting it may be unrealistic to expect that plant communities similar to those found on the undisturbed landscape will establish on all reclaimed landscapes after oil sands mining.

9.4.4.4 Seeding and Planting

For most woody species, transplants were more effective on tailings sand and overburden than cuttings or seed. However, transplantation was more costly. Common seedling mortality causes were herbivory, poor planting stock, planting time, lack of soil water, wind damage, erosion, disease, sand storms, and heavy snow. Literature reviews on selection and propagation of woody species for revegetation were conducted (Geographic Dynamics Corp. 2002; Hermesh and Cole 1983; Techman Engineers Ltd. 1983). Propagation methods for 55% of species identified as key for ecosite prescriptions (Oil Sands Vegetation Reclamation Committee 1998) had not been investigated (Geographics Dynamics Corp. 2002). Of 19 recommended shrubs, 7 had little or no research conducted on them; however, all tree species identified were studied.

Bare root stock, container stock, and plugs of numerous woody species established with high survival (Smreciu et al. 2001; Fung 1990; Russell Ecological Consultants 1987; Berg and Dai 1986; Russell 1985; Dai et al. 1983; Shopik 1983; Chu and Fedkenheuer 1980; Dunsworth et al. 1979; King 1978; Shopik and Cary 1977; Selner 1976; Massey 1973). In composite tailings on wetland and terrestrial sites, conifers performed best followed by deciduous species (Paquin 2002). Soil water was the greatest limitation to woody species cuttings; early spring planting increased survival. Unrooted cuttings were more cost effective than rooted cuttings but establishment and survival were lower (Fung 1992a, b; Russell 1985; Fung and So 1982; Fedkenheuer 1979b; Shopik and Cary 1977; Selner 1976).

Planting time effects on tree and shrub survival were investigated with little agreement in recommendations; survival was affected by ground cover and soil water (Berg and Dai 1986; Dai and Salayka 1983a; Dai and Salayka 1983b). Recommendations were made to avoid planting in early spring and late fall during high frost risk and in July when soil water was deficient (Konowalyk and Fung 1985). Planting rate and spacing recommendations varied considerably (Tuttle 1997).

Most boreal forest species have physiological dormancy, thus seeds require cold stratification to germinate (Baskin and Baskin 2001). Some shrubs and forbs have morphophysiological dormancy, requiring warm stratification followed by cold stratification. Some species with hard seed coats have

physical dormancy. Other means found to break dormancy included heat shock and chemical stimuli, such as smoke water which is easily handled and applicable to large scale projects (Mackenzie and Naeth current research). Scarification, stratification, and acidification have been applied to seed of native and introduced woody and herbaceous species. Most species established best from fresh seed; however, some species established after seed was stored for a year. Germination under controlled conditions was generally low (King 1978). Most tested species could be propagated from seed or cuttings (Fedkenheuer 1979b). Some required refined seed cleaning and easily propagated in containers. Plant genotype was considered a determinant in seed germination success under salt treatments (Khasa et al. 2002).

Grasses and legumes have been successfully broadcast, drill, hydro, and air seeded at various rates (Koning 1991; Fung 1986; Dai and Salayka 1983; Anderson et al. 1982; Fedkenheuer et al. 1980; Klym and Berry 1976; Massey 1973). Broadcast seeding produced thick uniform covers of small stunted plants while drill seeding produced stands with greater bare ground, more vigorous vegetation, and fewer non-native species. Grass cover was greater with drill seeding than broadcasting while legume cover was greater with broadcasting. Plant biomass was greater for all species when broadcast. Too vigorous a herbaceous cover reduced establishment and survival of transplanted trees and shrubs. Potential for hydraulic reclamation, or seed transport in peat, peat clay, and peat tailings sand slurries were investigated (Naeth and Wilkinson 2003). Slurry facilitated spreading seed over inaccessible soft deposits and may act as mulch for seed; tap water and more fluid slurries of peat, and tailings sand had greatest potential for establishment of native and agronomic species. Season of seeding had some impact on success, but results were inconsistent (Chu and Fedkenheuer 1980; Rowell 1979).

9.4.4.5 Vegetation Management

While weed control is a common site maintenance activity on many other revegetation projects, it is not a current focus in oil sands reclamation. Weed species are often considered a non-issue as they are not overly aggressive and provide ground cover on highly erodible surfaces, contributing to site stability and revegetation. This is not unlike the approach taken to annual weeds in many other types of reclamation. Herbicides have been used to reduce undesirable plant cover with variable results (Fung 1990; Fung 1986; Fedkenheuer et al. 1980; Dunsworth et al. 1979) but have not become general management practice.

Concern has been expressed regarding control of perennial weed species, which have a higher potential to negatively impact native plant community development than annual weed species. These potential negative impacts of weed species on revegetation are being addressed more fully in current plant community development studies, although data are not yet available. Concern has also been expressed that global climate change may create conditions under which weed species become more problematic. This concern would be no different in the oil sands than in other land use or reclamation scenarios, and to date has not been addressed.

While studies have included erosion control in their objectives, such control has not been directly tested. Most studies relied on qualitative or quantitative assessment of plant cover as an indication of erosion control potential (Fung et al. 2000; Grant et al. 1985; Dai and Salayka 1983; Takyi et al. 1977).

Cover of 34% or greater was considered acceptable for erosion control. Species that germinated and established readily, were generally deemed appropriate for erosion control. Peat addition reduced erodability of tailings sand; however, erosion reduction was dependent on peat type, application method, and tillage amount (Suncor 1983). Highly erodible slopes due to poor water retention and high surface temperatures increased sumping and runoff (Norwest Soil Research Ltd. 1976).

Severe small mammal damage to seedlings prevented successful revegetation in several studies (Russell 1985; Shopik 1980; Hardy Associates Ltd. 1978; AENV 1972). Deciduous species were more affected by rodents than conifers (Russell 1985; Fedkenheuer et al. 1980; Dunsworth et al. 1979; AENV 1972). Small mammal herbivory reduced plant establishment particularly when using bare root and container stock. The greatest pests were meadow voles, white footed mice, and red backed voles. Meadow vole populations increased exponentially on reclaimed sites once vegetation cover established. Grain treated with an anticoagulant rodenticide poisoned mice (Radvanyi 1980). Vexar cylinders, planting seedlings before ground cover establishment or when mice populations are in cyclic decline, sheet metal guards, and kill and pit fall traps were all effective controls (Pauls 1987; Green 1982; Green 1978). Vegetation cover reduction through plowing prior to planting reduced herbivory to almost nothing compared to use of herbicides or burning (Fedkenheuer et al. 1980).

9.4.4.6 Plant Community Development

Numerous studies, cited below, found little similarity in plant species composition, abundance, and cover between natural and reclaimed areas in the early years of reclamation. Reclaimed sites had fewer shrubs and more grasses and grass-like plants than natural areas with similar hydrologic and nutrient regions. What was seeded or planted had a considerable influence on the plant community, at least as monitored in the short-term. Time for plant community development must be considered; similarities between reclaimed and undisturbed sites would not be expected for many years after revegetation. The species richness of most revegetation seed mixes is considerably lower than that of natural plant communities; revegetation relied on transplanting trees and leaving native under story species to establish via natural recovery.

Native species encroached into reclaimed areas (Kelln et al. 2009; Mackenzie 2006). Whether communities were evolving towards typical ecosites of the region was unclear and not researched in any great detail, although key native indicator species were re-establishing in older reclamation areas. Over time, the native plant species composition in the understory increased and native species greatly exceeded non-native species. Where LFH or shallow soils from upland forests were selectively salvaged and placed, native species establishment was significantly improved and, over time, native plant species cover increased on LFH and peat mix caps, with LFH significantly outpacing peat mix treatments (Mackenzie 2006).

Of 137 reclaimed sites, varying in age from 1–15 years and in depth of peat from 0–15 cm, the type and amount of organic matter was a major factor in native species encroachment, with sites containing more organic matter having greater natural encroachment (Hardy BBT Ltd. 1990). Unseeded sites were largely invaded by agronomic species. Some weedy annual species stabilized soil and increased organic matter; however, they have little wildlife value. Natural encroachment rates and species were

similar between tailings sand and overburden sites (Dai and Salayka 1984). Natural encroachment by woody species was low regardless of reclamation treatment or site (Geographic Dynamics Corp. 2002; Hardy BBT 1990). Stockpiled or fresh peat was not a good source of native plant material, nor could it provide sufficient vegetation cover to prevent erosion (Fedkenheuer 1979a).

Low viable propagule abundance (Fedkenheuer and Heacock 1979), dilution of total propagule density from over stripping (Putwain and Gillham 1990), wind-dispersed weeds, and poor representation of species adaptable to drier soil conditions (Box 2003) suggest natural recovery is problematic for oil sands reclamation. Shaughnessy (2010) evaluated three long-term natural recovery areas. Plant communities were most influenced by substrate texture (clay), tree canopy cover, and tall shrub stem density. Communities developing from early successional lowland sites closely approximated upland boreal mixed wood forest in early to mid successional transition. This was in contrast to slow natural invasion into sites seeded to agronomic grasses and legumes after 15–30 years. Although herbaceous species quickly invaded unseeded areas, natural invasion of shrubs and trees appeared to be very slow.

Water supplied by soil caps with varying depths of clay loam secondary material, influenced plant community composition and tree growth (Kelln et al. 2009). Trees were on target to meet minimum Alberta regeneration guideline heights for mixed wood stands on fine textured ecosites after 8–14 years. Aspen on 35 cm covers lagged behind those on 50 cm and 1 m covers in height and root collar diameter; plants on 35 cm covers had reduced physiologic function. Thicker caps with more clay loam secondary material, and therefore more soil water, had higher native plant species density and cover. Early plant community composition was insensitive to peat mix capping depth over a fine textured secondary layer and peat mix depth, but was sensitive to LFH depth (Mackenzie 2006). Shallower LFH removal resulted in more exposed mineral soil, which was not as suitable for germination or rooting as material rich in organic matter. Even thin LFH, with significant mineral soil exposure, outperformed peat mix in native plant community establishment due to the large amount of native plant propagules provided by LFH, the greater number of microsites, and potentially improved nutrient status.

Light levels in the developing forest influenced understory composition, with tradeoffs between high levels of timber productivity (uniform dense stand, low levels of light reaching forest floor) and understory diversity (Kelln et al. 2009). While fast-growing aspen seedlings had less growth on 35 cm covers where water was limiting, slow-growing spruce were larger on 50 cm covers. Understory competition was implicated, although for 1 m covers, native plant density and cover was highest, illustrating tradeoffs between tree productivity and understory communities even at this early stage.

Forest management units commonly had diverse productivity in similar soils and ecosites, due to soil variation, disease, age, and mapping scale (Kelln et al. 2009). The resulting productivity range was atypical for a capability class or expected growth pattern but contributed to ecological diversity. Local lower species richness reflected the limited pool of vascular plant species capable of colonizing natural saline habitats. At a study area scale, saline landscapes had higher species richness, due to edaphic heterogeneity and inclusion of halophytes in the local species pool. Thus, heterogeneity in canopy composition, canopy density, canopy distribution, and the edaphic environment have potential to increase diversity in the reclaimed landscape. Reclaimed landscapes should be allowed such variation and diversity when establishing growth targets for certification.

Plant diversity on reclamation treatments was stable before declining with advancing canopy closure at 31–35 years, when understory species began to disappear (Rowland et al. 2009). Reclamation treatments had more bare ground, grasses, and forbs but less moss, lichen, shrubs, trees, or woody debris than natural forests (Rowland et al. 2009; Rowland 2008). Rates of litter decomposition were lower on reclamation treatments. Development of an organic layer was facilitated by shrubs. With repeated fertilizer applications, variables for peat-mineral amendments fell within the range of natural variability at about 20 years. An intermediate subsoil layer reduced the need for fertilizer and conditions resembling natural forests were reached 15 years after fertilizer application. Tailings sand covers receiving one fertilizer application appeared to be on a different trajectory to a novel ecosystem.

Root distribution in reconstructed soils and undisturbed forests was similar and soil materials did not restrict root development even between soil caps and underlying secondary material (Yarmuch 2003). Rooting depth and distribution in soils constructed by different soil replacement techniques were similar to natural soils with most roots in the top 15 cm (Macyk et al. 2004). Roots of mixed wood stands on saline sodic overburden followed a similar pattern with soil depth as those from undisturbed boreal forest stands and appeared unaffected by saline sodic overburden (Lazorko 2008).

A disproportionate amount of revegetation research has been conducted on woody plant species, since woody plants are only one component of the desired end land use. Plant community development as an indicator of success involves assessment and evaluation of soil and vegetation successional processes. If successful plant community development and desired ecosite prescriptions are to be achieved, diversity will need to be emphasized at landscape and site levels and include species, functional groups, topography, and microsites.

9.4.5 Re-Establishing Faunal Biodiversity

Faunal biodiversity loss with oil sands development is a critical issue garnering much attention. There is debate as to the impact that oil sands developments and operations have had and will have on faunal biodiversity and on the likelihood of any reduced faunal biodiversity being reinstated with reclamation. Although it is difficult to address the latter point until more reclaimed areas have been certified and more time has passed for reconstructed ecosystems to develop, some key issues can be addressed via the research to date.

Oil sands development creates several landscape components damaging to fauna, including open pit mines, tailings ponds, and operations infrastructure. These features are mainly associated with direct habitat loss and alteration and fragmentation of additional habitat. Although in situ operations are expected to disturb a smaller area than mining, there is still much concern surrounding habitat fragmentation from seismic lines, roads, pipelines, well pads, and power lines, which increase the overall area of impact. The loss and fragmentation of habitat and subsequent biodiversity is of concern from ecological and land use perspectives, including traditional land uses. Even though these areas will be reclaimed, there is a long time between habitat destruction and successful reclamation. Many oil sands companies are attempting to deal with these inevitable habitat losses with conservation offsets and complementary strategies including enhancing reclamation, enhancing mitigation efforts and conserving substitute forest areas so no net loss of critical habitat is maintained in perpetuity. Although

environmental impact assessments associated with oil sands development state no net loss of wildlife habitat will occur because land will be reclaimed, numerous reports have cited habitat loss and fragmentation as the single greatest threat to wildlife in the oil sands region (Gould Environmental 2009; Gillanders et al. 2008).

According to some studies, there is insufficient functional habitat to maintain and increase current caribou distribution and population growth rates within the Athabasca landscape area; boreal caribou will not persist for more than two to four decades without immediate and aggressive management intervention (Athabasca Landscape Team 2009). All monitored caribou populations in the Athabasca oil sands area are currently in decline, and recent trends and simulation modeling results indicate that there is a high risk that the populations will not persist for more than forty years. Caribou movement is predicted to be affected by oil sands operations, particularly in situ; thus the above concerns are magnified by oil sands disturbances. Few studies exist on the actual impact of oil sands on caribou, although some studies can reasonably be used to predict impacts. Seismic lines were not barriers to caribou movements, but roads with moderate vehicle traffic acted as semi-permeable barriers to caribou movements, particularly during the winter (Dyer et al. 2002; Dyer et al. 2001), suggesting the large area of road development in oil sand mining areas will impact winter movement of caribou.

Above-ground pipelines for in situ oil sands development are potentially significant vectors of habitat fragmentation for other large mammals such as moose, although pipeline crossing structures facilitated movement across the pipeline and were used more than sections of elevated pipelines by all species (Dunne 2007; Dunne and Quinn 2008). Although concerns centre around impacts on other large mammals, there are no studies to document those impacts.

There is particular concern for birds in the oil sands region (Wells et al. 2008) as many species showing significant decline are highly dependent on the boreal forest of the oil sands region. Millions of birds are projected to be lost from mining and in situ operations in the oil sands; millions more are projected to lose their breeding habitat and thus offspring over a period of years. There is evidence that birds are affected by high noise levels associated with industrial activities (Bayne et al. 2008), suggesting oil sands operations will have a similar effect. Some species treat linear disturbances as territory boundaries which can result in reduced abundances of those species (Machtans 2006; Bayne et al. 2005).

There were no differences among reclaimed wetland sites for tree swallow reproductive success, nestling growth rate, and immune response that could be attributed to tailings or tailings pond water additions (Smits et al. 2000). Increased ethoxyresorufin-o-deethylase (EROD) (a biomarker of chemical exposure activity) confirmed the presence of xenobiotics in the diets of nestlings from two sites, while the main reference site was relatively free of EROD inducing compounds. Dietary analyses showed that 84% of the food items of the tree swallow nestlings were of aquatic origin, likely from the local wetlands, and thus would be expected to provide a good reflection of biological effects of any mining related contaminants accumulating through the food chain.

One study found large scale and rapid development negatively affected boreal bird populations and community structure on oil sands sites, making reclaimed areas inappropriate habitat for birds

(Dagenais 2009). In another study, tree swallows nesting on tailings sands were exposed to unrecovered bitumen, NA, and PAH (Gentes et al. 2007; Gentes 2006). Reproductive success was very low on oil sand process water material sites compared to the reference site in one year, but relatively unaffected the next year. Nestlings on oil sands had higher thyroid hormone levels and suffered parasitic burdens twice those of reference site nestlings. Nestling growth, hematocrit, blood biochemistry, organ weights, and EROD activity appeared unaffected by NA. No toxic changes were detected on histopathological evaluation of major organs, suggesting exposure to other chemicals such as PAHs is a greater concern than exposure to NA. Nests on wetlands containing water and sediments affected by chemicals related to the oil sands extraction process were more heavily infested than nests on a control site. Nestling growth was negatively affected by parasite load on industrial sites but not on the reference site. Harms et al. (2010) tested the same populations of tree swallows and showed that there were no negative effects on the reproductive performance of resident adults or on innate and acquired immune function in juveniles (nestlings) exposed to oil sands process affected materials. This study was conducted when weather conditions were near ideal which still leaves some question as to whether these responses would be sustainable under other conditions.

9.4.6 Wetlands Reconstruction

Wetlands, including bogs, fens, and marshes, are important components of the undisturbed landscape in oil sands mining areas. Since surface mining leaves no remnants of wetlands to recover, they must be reconstructed in the reclamation landscape. Reclamation of peatlands (fens or bogs) after mining in the Athabasca boreal region has not been demonstrated. Since peatlands became established naturally over several thousands of years, many consider it unlikely they can be developed in the 80–100 years considered for reclamation (Sherrington 2005). Marshes and ponds which regenerate more quickly are predicted to replace these peatlands in reclaimed lands and some constructed wetlands are currently being evaluated. There is further concern that a significant amount of wetland loss will occur through its conversion to upland habitat after oil sands development and reclamation.

Research outside the Alberta oil sands region suggests peatland restoration may be possible. Although sphagnum mosses are not considered easy to manipulate on artificial substrates or in constructed environments, large expanses of cutover peatland can be revegetated at a relatively low cost (Rochefort and Lode 2006). Fen restoration of peat fields used for agriculture has been studied in Europe and sphagnum cultivation in nurseries in many countries is promising. The re-establishment of former hydrological characteristics in undisturbed fens and bogs, and re-introduction of peat forming plants (sedge or sphagnum species) in mined peatlands have in many cases been highly successful (Richert 2000; Boudreau and Rochefort 1999; Price et al. 1998; Ferland and Rochefort 1997), suggesting it is possible to recreate conditions favourable to the growth of typical peatland plants. North American peatland restoration techniques have been viewed as promising from a paleoecological perspective (Lavoie et al. 2001). Long-term monitoring of current restoration projects is needed to confirm whether it is possible to restore ecological functions of the cutover peatland to bring it back to a peat accumulating ecosystem.

Soil transfers from natural wetlands increased plant colonization on reclaimed composite tailings wetlands (Cooper 2004). Reasonable plant cover was established and health assessment and rooting

depth indicated no physical or chemical limitations for most species. Composite tailings subsoil reduced emergence from seed banks. Although species composition differed between created and natural wetlands, species replacement sequences of reclaimed wetlands paralleled natural wetlands.

The physiological effects of oil sands process water (OSPW) on plant species were studied, including effluent seeping from dykes, composite tailings effluent treated with gypsum, effluent polished with phosphorus, on site wetland water, and off site wetland water (Crowe et al. 2002; Crowe et al. 2001; Crowe 1999). The composite tailings wetland had the lowest floral biodiversity, not surprising since seed germination was inhibited. Overall, cattail and clover were physiologically adapted to the oil sands effluent.

Trites and Bayley (2009a) surveyed 25 natural wetlands and 10 industrial wetlands on oil sands areas. Electrical conductivity was 0.5–28 mS/cm in the wetlands, indicating salinity similar to or higher than anticipated for oil sands reclamation is naturally present in some boreal wetlands. Species richness was low in both industrial and natural wetlands, decreasing with increasing electrical conductivity and pH and increasing with soil organic matter. Industrial wetlands resembled boreal or prairie marshes but not all community types were present, indicating planting may be required to enhance diversity. In three oil sands wetlands, despite a negative correlation between peak biomass and salinity, salinity did not reduce the potential to accumulate organic matter because some salt tolerant species had slower decomposition rates (Trites and Bayley 2009b).

Coke amendments did not significantly increase trace metals in pore water or in associated macrophytes and invertebrates (Baker 2007). Growth of resident macrophytes was not prohibited by coke amendments. Overall, local coke amendment effects were detected in a reference wetland but not in two constructed wetlands with other oil sands processed material.

The proportion of petroleum derived carbon from oil sands process material affected wetlands, with 62–97%, nitrogen enrichment from bitumen extraction or wastewater disposal (Daly 2007). There was evidence of transfer of carbon and nitrogen assimilated by microorganisms to higher trophic levels. Production and methanogenesis by bacterioplankton were inhibited by salinity and/or sulphate. Amending wetlands with peat cover did not affect bacterial production or stimulate decomposition, which would lead to carbon losses over time, and did not affect potential carbon transfer to higher trophic levels. Unvegetated wetland sediments were net sources of carbon and not on a trajectory to be net sinks at this early stage of wetland development. Overall, microbial functional processes were not the same as in natural wetlands of equivalent age.

Using constructed wetlands as treatment systems for OSPW removed 32–99% of ammonia and 19–76% of hydrocarbons (Bishay 1998). Removal rates decreased as input load increased; the loads removed were about 200 mg / m^2 / d for ammonia and 170 mg / m^2 / d for hydrocarbons. Dominant fate pathways were sediment retention and nitrification/denitrification for ammonia and sediment retention and microbial mineralization for hydrocarbons. Macrophytes appeared to grow and thrive during the three years of application. The treatment wetlands provided significant contaminant retention under lighter loading and macrophyte production and decomposition were not impacted at these lighter loadings.

Constructed wetlands of oil sands process materials such as tailings and or bitumen extraction water had highest conductivity and napththenic acids (NA); salinity was high but declined (Leonhardt 2003). Oil sand process material wetlands had lower sediment organic matter than high conductivity wetlands in one year but higher the next. Richness but not abundance was significantly lower in young oil sands process material wetlands than in natural wetlands, depending on inputs of process materials. Water pH, NA, detrital abundance, conductivity, salinity, and sediment were associated with taxa richness. Abundance was correlated with extent of macrophyte development, water conductivity, and detrital abundance. Water toxicity, sediment characteristics, and development of macrophytes may initially limit zoobenthic community development in oil sands process material wetlands.

Mechanisms of initiation and early development for boreal wetlands showed marshes did not develop into peat forming wetlands (Bloise 2007). Bulk density of marsh organic material was significantly higher than that of peat forming wetland sites. Peat forming wetland samples had significantly higher mean water content than marshes or drained peatlands. There was no conclusive evidence that the immediate underlying mineral substrate influenced basal peat chemical or physical properties. No correlations were found between basal peat chemical or physical properties and mineral soil chemical or physical properties. Thus reclamation efforts must set up conditions conducive to peatland formation, including slight acidic environment, relatively high water table, and fine textured soils.

Price et al. (2009) proposed a conceptual model to replace fen systems with fen peat materials supported by ground water inflow from a constructed watershed. Optimal conditions were achieved using an upland area at least twice that of the fen, underlain by a sloping (3%) layer of fine grained material. Using daily climate inputs that included 1998, the driest summer on record, the model suggested adequate wetness can be sustained in the fen for the growing season, and the extent of water table recession was similar to undisturbed systems during that period.

9.4.7 Tailings Ponds Reclamation and Management Research

Tailings ponds reclamation and management have been the subject of much concern and controversy, with many sceptical that tailings ponds can ever be reclaimed. Much historical reclamation research has been done on tailings dykes and tailings material, with less on the tailings ponds themselves. The main reclamation research foci had been dewatering and floral and faunal toxicity. Research on bioremediation and remediation of tailings ponds is ongoing. The section below addresses research more directly applicable to tailings ponds reclamation and management, whereas characterization of water quality and quantity are addressed in Section 8. There is no definitive research to indicate how tailings pond reclamation should proceed, other than the dyke and tailings sands reclamation which has been addressed in various other parts of this section.

No end pit lake (EPL) has ever been successfully reclaimed and there has been no demonstrated effective long-term way to deal with liquid tailings. However, various toxicity tests in the laboratory and the field indicated a reclaimed tailings pond would be capable of undergoing transformations to remove toxicity and allow biologically complex aquatic communities of phytoplankton, invertebrates, and fish (Nix and Martin 1992).

Numerous plant species have been tested for their ability to dewater and stabilize oil sands tailings.

Plant root systems can reinforce tailings substrates, thereby reducing erosion (Silva et al. 2002: Silva 1999: Johnson et al. 1993). Plant biomass adds organic matter which can improve structural and nutrient properties of tailings and promote plant growth and development. Successful vegetation establishment on soft deposits can contribute to dewatering through evapotranspiration, subsequently decreasing liquid content, increasing surface stability, increasing shear strength and bearing capacity in the root zone, and allowing the substrate to be traversed. Roots provided fibre reinforcement, contributing to increased bearing capacity of tailings. Phytoremediation has been proposed for tailings pond reclamation (Mehta 2006). Tree species have decreased the pH of tailings and increased mineralization rates, general microbial population, and microbial diversity. Further research is required for this approach.

NA are typically found in ionized form in oil sands process water. Little is known about NA fate in plants (Li et al. 1997; Xu 1995). Three native emergent plant species did not enhance NA dissipation from a hydroponic system (Armstrong 2008). A commercially available NA mix was more phytotoxic than oil sands NA. The rhizosphere community changed with NA exposure, with potentially pathogenic bacteria increasing and bacteria beneficial to plant growth decreasing. Significant physiological changes occurred to roots exposed to NA, including epidermal cell death and a chemical change of parenchyma cells in the pith.

A primary issue in the choice of a given bioremediation approach is the characteristics of the contaminated water system (Quagraine et al. 2005). The tailings ponds have high concentrations of NA and naphthenic salts. Aerobic bacterial populations have demonstrated capability for degrading NA. A recalcitrant component of NA resists further biodegradation. Some plausible options to further degrade the NA in the tailings pond water include bioaugmentation with bacteria selected to degrade the more refractory classes, use of attachment materials such as clays to concentrate both NA and NA-degrading bacteria in their surfaces and/or pores, synergistic association between algae and bacteria consortia to promote efficient aerobic degradation, and biostimulation with nutrients to promote the growth and activity of the microorganisms.

MFT over CT lowered calcium, magnesium, and sulphate concentrations and electrical conductivity compared to just CT (Luo 2004). Both layers were rich in methanogens and sulphur-reducing bacteria. Unamended tailings sand and 10 cm each of muskeg peat, mineral overburden, and tailings sand mixed together were lower in soil organic matter content than 8 cm of muskeg peat over tailings sand (Mensforth 1984). Total microbial biomass and soil basal respiration were greatest in soil composed of 8 cm of muskeg peat laid over tailings sand. The total microbial biomass and soil basal respiration increased with age.

9.5 Summary of Issues

There is clearly uncertainty and opportunity for disagreement and misunderstandings in reclamation of oil sands operations due to the plethora of interpretations of key land reclamation terms such as reclamation, restoration, native species, end land use, and equivalent land capability. Regulators, industry, and other stakeholders continue to use the various terms and their definitions, and develop new ones, to suit their arguments or support their issues. There is no current plan for standardization of

terms, although standardization would enhance the general understanding of reclamation goals and expectations, timelines for their achievement, and the measures of their achievement.

An acceptable end land use and time frame for its development have not been clear for oil sands mining operations prior to approval which makes it difficult to clearly define and standardize reclamation evaluation parameters and methods for assessing those parameters. Although progressive reclamation is an idealized approach to any environmental disturbance, it has not been adequately addressed within the reality of temporal, spatial, and operating requirements for oil sands mining operations. Addressing this issue, and making the limitations and possibilities more transparent would greatly aid in stakeholder understanding and acceptance.

Because of the very small amount of land certified to date relative to the large area that has been disturbed in the oil sands region, there is major scepticism as to whether reclamation to an equivalent land capability can be achieved in a reasonable time frame. With so little certified reclaimed land to evaluate, the likelihood of reclamation to any of the interpretations of equivalent land capability has been based on land that has been reclaimed but not yet certified and on reclamation research to date. Research to date in oil sands mined areas shows high potential for reclamation of upland ecosystems from soil and vegetation perspectives. Some issues regarding groundwater and salt movement remain to be addressed (see Section 8). Although some wetlands reclamation research is ongoing, and research elsewhere is promising, quantitative data are currently lacking to confidently determine whether wetland reconstruction will be successful, particularly in the long-term. Current trajectories indicate some wetlands have been constructed after oil sands mining and are developing, and peatlands reclamation outside of the oil sands shows promise.

Past research on tailings ponds reclamation has focused on dewatering MFT and on floral and faunal toxicity. Bioremediation and remediation of tailings ponds research is ongoing, coupled with new ways to deal with tailings outside of the traditional tailings ponds.

Although impacts of oil sands operations on faunal biodiversity have been speculated upon, few research data exist to substantiate or refute the concerns. This reality exists mainly because so little land has been reclaimed and what has been reclaimed is in small parcels interspersed within active mining areas.

The expected time frame for reclamation has not always taken ecosystem development into account. Regardless of the parameters evaluated, early successional landscapes after reclamation will be quite different than the late successional landscapes that have been removed for mining. Reclamation needs to be viewed not as a state but as a process. Although an appropriate trajectory towards boreal forest may be achieved within five years, that five-year-old landscape will look quite different than the mature forest it should become in later decades. With reclamation, basic ecological processes have been redeveloped, which should shape the newly evolving landscape towards equivalent land capability. A better understanding of the trajectories reclaimed sites will express is needed in the form of long-term plant community and soil development data to quantitatively determine if the expressed early reclamation trajectories are moving in the right direction.

Although the evolving ecosystem development trajectories may support many traditional and other

land uses, reclaimed lands are not readily available for use until they are certified reclaimed. That lack of availability and the expectations for mature forest landscapes foster the perception that the lands are not reclaimed. This ties to the comments on progressive reclamation above.

10. PUBLIC HEALTH

10.1 Introduction

In this section of the report, the objectives are to present and assess major health impacts of the oil sands industry as well as identify appropriate options to manage those impacts. For the purpose of this assessment, health is considered in a holistic way, according to the definition of the World Health Organization. Health is: "*a state of complete, physical, mental and social well-being and not merely the absence of disease or infirmity*" (WHO 1967) and, "*the extent to which an individual or a group is able, on the one hand, to realize aspirations and to satisfy needs, and on the other, to change or cope with the environment*" (WHO 1984).

To evaluate the health impacts of the oil sands industry, the biophysical aspects of health are considered as well as the psycho-socio cultural determinants of health which also play a significant role in determining the direct and indirect health effects of such projects. The list of health determinants considered as part of this section of the report, as recommended in the Canadian Handbook on Health Impact Assessment, are: physical environment, social support networks, employment and working conditions, income and social status, personal health practices and coping skills, biology and genetic endowment, health services, and healthy child development and education (Health Canada 2004).

Based on this broad definition of health, oil sands projects may have already created significant human health impacts, both positive and negative. An often cited beneficial effect is job creation, which contributes to a better standard of living. Economic benefits are frequently linked with positive indicators of health such as longevity and lower occurrence of disease. This benefit is particularly important for chronically under-employed groups, such as the First Nations.

However, oil sands projects also have the capacity to cause adverse health effects at the individual and community levels. Negative effects associated with such projects can be directly related to physical health, such as exposure to high levels of contaminants in the environment which may contribute to increase the rates of serious chronic diseases such as cancers, respiratory or cardiovascular diseases, or infectious diseases. Direct health effects can affect both workers and the public through industrial hazards, environmental pollution, and injury risks. Negative effects may also occur at the community level, for example when facing a loss of socio-cultural well-being, or experiencing social disruption and violence. In these cases, the adverse health impacts may translate into increased stress, anxiety, and isolation in a community. Other behavioural responses may also be impacted, notably smoking, exercising, alcohol consumption, and the like.

Ultimately, multiple projects' impacts from both direct and indirect aspects of development may result in cumulative health impacts, which can be additive or even synergetic in nature. In this assessment, the cumulative impacts on health are addressed only in a broad manner, but specific options and needs are identified to assess cumulative effects.

The first step of this assessment is to summarize the public health profile in the oil sands region. The second step describes the major possible health impacts. The third step examines the current regulatory

framework and practices which allows performance to be assessed against objectives. This is also done by evaluating the significance of health impacts against set criteria. Finally, the last step is to identify gaps and to provide options for closing the gap.

Relying on valid and reliable information was crucial for the analysis and objective assessment of health impacts. A comprehensive search of the scientific literature was conducted in the fall and winter 2009–10. The complete search strategy is available in Appendix A9. This literature review reveals that there are major gaps in the published and particularly peer-reviewed scientific literature on many of the topics to be reviewed in this section. Given the size and importance of the oil sands development, a finding of major gaps in knowledge concerning public health impacts poses a concern in itself.

10.2 Public Health Profile

In this section, the objective is to give an overview of public health trends in the oil sands region for the past twenty years. Public health trends are defined as a set of statistics expressing a general direction in which health determinants and outcomes tend to move over time. Usually, trends are used to identify emerging health issues, document health tendencies, compare health behaviours across regions, and measure progress toward health goals. These data gathered through the years provide important information for policy-makers to improve public health with the development of specific programs. Providing public access to these data is an important and noteworthy feature which has facilitated our review.

For the purpose of this report, these statistics will serve as a point of reference to characterize the health status of the population currently living within the oil sands region. The goal is to compare the health status of this population against the population of Alberta as a whole, in order to identify potential disparities. Of vital importance is a recognition that the units of analysis are necessarily populations, rather than individuals. Consequently, drawing conclusions or making confident inferences about cause-effect relationships is not possible in these circumstances. This reality is a well-established foundation of public health research and is critical to understand the limitations of our analysis, but also a reason for caution about some of the speculation reported in the media concerning health impacts. Because not enough is known about the specific individuals in the groups, any conclusions on causation would be subject to biases that cannot be controlled for. Nevertheless, this analysis is a first approach in examining the health status of the population living near oil sand projects.

The results of this analysis focus on the Northern Lights Health Region (NLHR), which was the largest (geographically) of nine health regions in Alberta, before the province-wide reorganization of health services in 2008 (Section 10.4). NLHR included over twenty remote and rural communities spread across Northern Alberta (Figure 10.1). Others of the former health regions (Peace Country, Cold Lake, and Aspen) are affected to a lesser degree by oil sands development.[10] Statistics are also presented for Wood Buffalo,a large municipality occupying the most populated, eastern portion of NLHR, which

[10] Surface mining operations with associated tailings ponds combined with on-site bitumen upgraders in some cases are only found in NLHR.

consists of nine small rural communities including Fort McKay and Fort Chipewyan plus the city of Fort McMurray (Figure 10.2, Figure 3.3).

Figure 10.1 Alberta's nine health regions

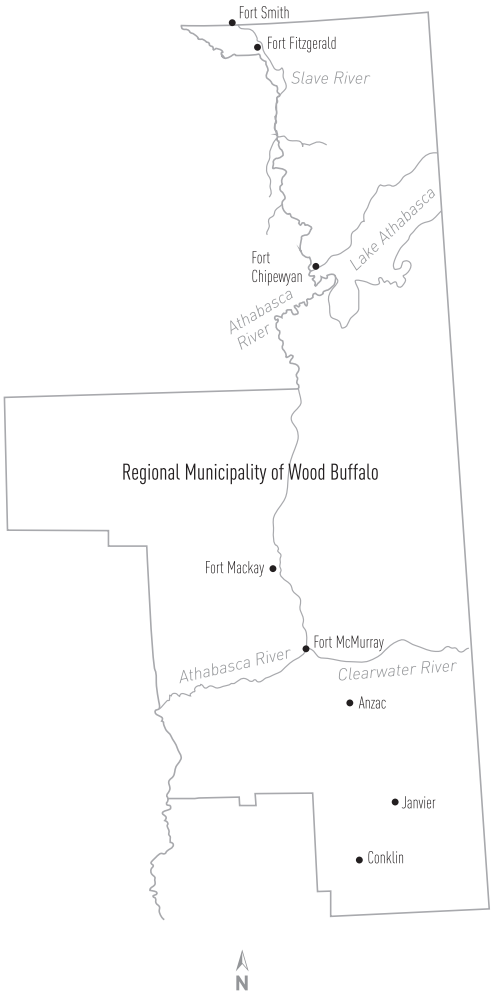


Figure 10.2 Regional Municipality of Wood Buffalo[11] until 2008

The comparisons of characteristics for the Wood Buffalo region or Northern Light Health Region versus the entire province will inevitably encounter the instability of small numbers. Most of the characteristics being compared are expressed as rates which are calculated as the number of items of interest divided by the total affected population to give a rate per unit of population. Clearly, smaller population regions will show larger changes in rates over time compared to the larger ones.

Another important consideration in the following data comparisons is that Calgary (Calgary Health Region) and metropolitan Edmonton (Capital Health Authority), both urban areas, have a combined population of almost 2.1 million, which is 57% of the total population of the province. Another 360,000 of Alberta's population (10%) resides in cities that are distributed across the other health

[11] Sources: (RMWB 2009; AHW 2010a)

regions. Because there are a number of differences between urban and rural areas of Alberta, some of which inevitably influence health statistics, it is necessary to consider the urban/rural influence when comparing RMWB with the entire province. This will be dealt by also considering the adjacent Peace Country Health Region, which has one major population centre (Grande Prairie) somewhat like Fort McMurray, making it a reasonable comparison among the choices available. The Peace Health Region has forestry, pulp and paper, some agricultural, conventional oil and gas industry, in situ oil sands development only, and it has not boomed nearly as much RMWB, particularly in terms of the influx of construction workers.

Statistics in this section were mostly obtained from data available in the Interactive Health Data Application (IHDA), an online tool designed by the Alberta Ministry of Health and Wellness, in which specific health indicators are available for various years (AHW 2010b). Also, a 2007 report called *Health Trends in Alberta – A Working Document* summarizes statistical information about the health of Albertans during 2003–2006, and was useful to comprehend most recent trends (AHW 2007b). An Alberta Cancer Board report and Statistics Canada online data were also used as sources (ACB 2007; Statistics Canada 2010).

The statistical information, presented below, is divided in seven subsections: demographics, mortality, income and employment, behavioural risk factors, mental health, incidences of chronic and infectious diseases, and healthcare system characteristics.

10.2.1 Demographics

Changes in population often indicate the growth or stability of a community, as well as the need for increased or for different resources and services. There are three main data sources for population counts in Alberta: the Alberta Health Care Insurance Plan (AHCIP) Registry[12] (available in the IHDA), the Census of Statistics Canada, and Alberta Municipal Affairs.[13]

According to Alberta Health and Wellness, the Northern Lights population estimates went from 53,133 in 1989 to 89,023 in 2009, corresponding to an increase of 70.3% in a twenty-year period, while a 45.2% increase was recorded for the same time period for Alberta overall (AHW 2010b).

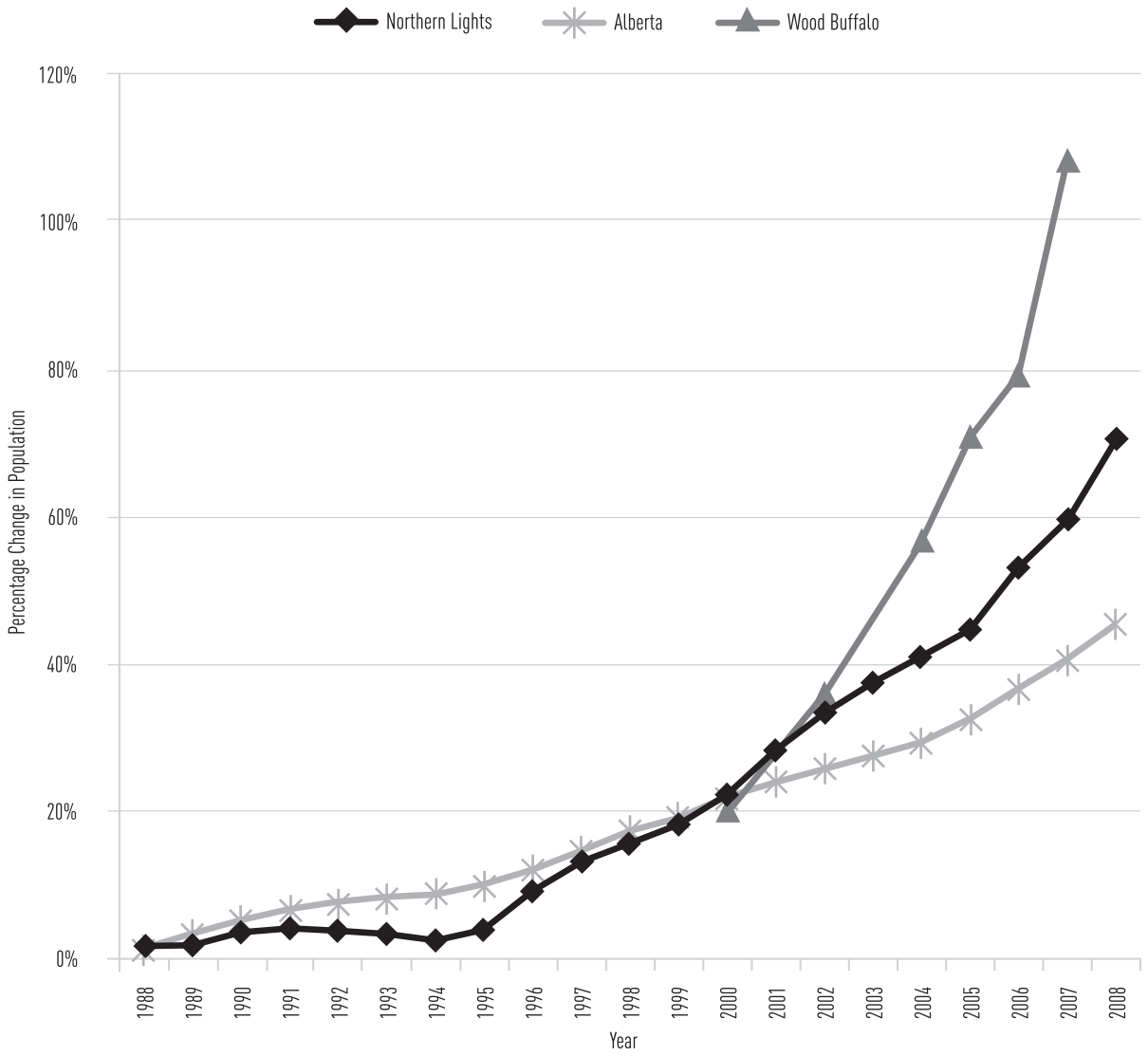
Alberta Municipal Affairs reports a population for Fort McMurray of 78,792 in 2006. For the Regional Municipality of Wood Buffalo (RMWB), Statistics Canada reports a population of 51,496 in 2006 (Statistics Canada 2007). RMWB Census report indicates a population of 76,735 in 2006 (RMWB 2007).

The data (Figure 10.3) indicate that the population boom is so rapid and transient in nature that it is likely difficult to accurately monitor population growth. The Government of Alberta has acknowledged the inconsistency in data which may be due in part to AHCIP coverage which requires a 90 day presence in Alberta to apply for coverage and a physical presence in Alberta for at least 183 days in a

[12] Because Alberta (as is mostly the case across Canada) has a single payer healthcare insurance scheme for the general population, the AHCIP data base covers all healthcare transactions covered for AHCIP-insured residents.
[13] Alberta Municipal Affairs 2010. http://www.municipalaffairs.alberta.ca/mc_official_populations.cfm.

12-month period to be covered.[14] This may lead temporary workers to be treated for medical problems in their province of origin and to be counted as being residents of their province, thus underestimating actual rates for chronic diseases in Alberta.The population of transient, non-residents of Alberta who have come to the oil sands region would certainly be under-represented in available data sources.

Figure 10.3 Percentage change in population between 1989 and 2009, in the Northern Lights Health Region (NLHR), Alberta and in the Regional Municipality of Wood Buffalo (RMWB)



Sources: RMWB 2007; AHW 2010b

[14] *Comparison of Alberta Population Counts Between the AHCIP Registry and the 2006 Census:* "Fort McMurray is considered the gateway city to the northern Alberta oil sands developments. Generally speaking, it is likely that the oil industry attracts a disproportionate number of young male workers. Hence, on the 2006 Census Day, a large number of this group might not yet have been eligible for AHCIP registration due to interprovincial migration, others might not have had AHCIP coverage despite being eligible, while others might not have updated their address with AHCIP administration. Individuals who commute between their residence and work place located in different geographic areas for longer periods of time contribute to the variations as well."

To establish a well-founded public health profile, reliable numbers are needed. In fact, population size is vital information for calculating other health indicators. For example, the incident rate of diseases,[15] an indicator of new cases within a specified time period, is a function of population size.

10.2.1.1 Aboriginal Ancestry

Indian and Northern Affairs Canada defines Aboriginal Peoples as "*a collective name for the original peoples of North America and their descendants.*" RMWB includes the reserves and traditional lands of five First Nations which are comprised of native Cree and Chipewyan individuals.[16]

According to the Statistics Canada 2006 Community profile, 10.4% of the population in RMWB is identifying with at least one Aboriginal group compared to 12% in 2001 and 13% in 1996.[17] In contrast with the overall trend in Alberta, the Aboriginal population in RMWB has been decreasing as a proportion of the total RMWB population since 1996. The overall trend in Alberta is caused by a higher birthrate among the Aboriginal population than in the non-Aboriginal population, but the rapid population growth in RMWB caused by in-migration has overwhelmed the province-wide trend.

Table 10.1 Percentage of respondents who identified with at least one Aboriginal group in RMWB compared to Alberta for 1996 and 2006

Years	**RMWB**	**Alberta**
1996	13%	4.6%
2001	12 %	5.3%
2006	10.4%	6%

Source: Statistics Canada population census (Statistics Canada 1996, 2001, 2007)

10.2.1.2 Mobility Status

In 2006, 21% of residents in Fort McMurray lived in a different province or territory five years ago compared to 7% for the residents of Alberta.

According to Statistics Canada, in 2009, 9.5% of the population was immigrant (referring to persons who are, or have ever been, landed immigrants in Canada) compared to 16.2% for the rest of Alberta (Statistics Canada 2009). These data suggest that the migration coming to WBRM is predominantly coming from non-immigrant Canadians.

[15] Incident rate of a disease = number of incident (new) cases of the disease / total population of the region under study.
[16] The Mikisew Cree First Nation is the largest with about 2,550 registered members in nine reserve areas located in and around Fort Chipewyan. The Athabasca Chipewyan First Nation has a registered population of 888 and eight reserve areas. The Fort McKay First Nation has five reserve areas with about 648 registered members. Fort McMurray No. 468 First Nation has four reserve areas and 608 registered members. Chipewyan Prairie Dene First Nation has about 704 registered members and three reserve areas located in and around the community of Janvier/Chard.
[17] Included in the Aboriginal identity population are those persons who reported identifying with at least one Aboriginal group. The 2001 and 2006 census experienced some under-reporting among some First Nations but we have no basis to judge the impact of that phenomenon on the data for First Nations in the oil sands region.

10.2.2 Chronic Diseases and Some Related Mortality

Age-adjusted mortality rate by cause of death is a measure of the frequency at which deaths occur in a given population due to a certain cause. Rates presented are age-adjusted to reduce the potential confounding effect of different age structures (i.e., across geographic boundaries or years).

Mortality rates from chronic diseases in Northern Lights are lower than the provincial average for the years 2003 to 2005 (AHW 2007b). This trend has been observed for various chronic diseases such as liver, kidney, and heart diseases as well as chronic obstructive pulmonary disorders (COPD) and diabetes (AHW 2007b). For cancer, the same trend seems to be true for lung, prostate, cervical and breast cancer (AHW 2007b).

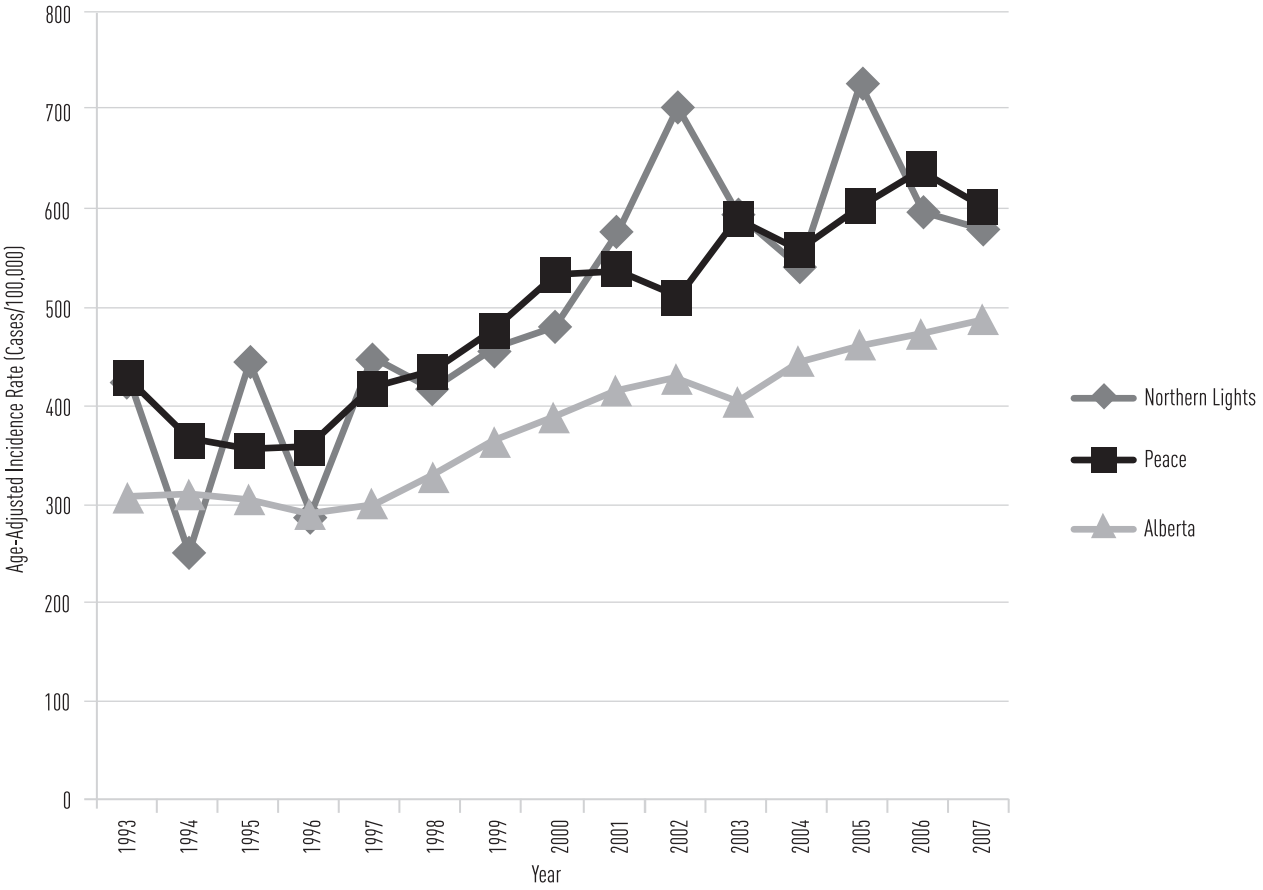
10.2.2.1 Incidence Rates for Cancer

Age-standardized incidence rates for all cancers, lung cancer, colorectal cancer, female breast cancer, and prostate cancer are presented for each of Alberta's nine health regions in a yearly report by the Alberta Cancer board. However, it is important to note these rates are three-year averages. The 2007 report show rates of incidence for all cancer lower than or equal to provincial average except for prostate cancer which was higher in Northern Lights (ACB 2007).

10.2.2.2 Incidence and Prevalence Rates for Diabetes

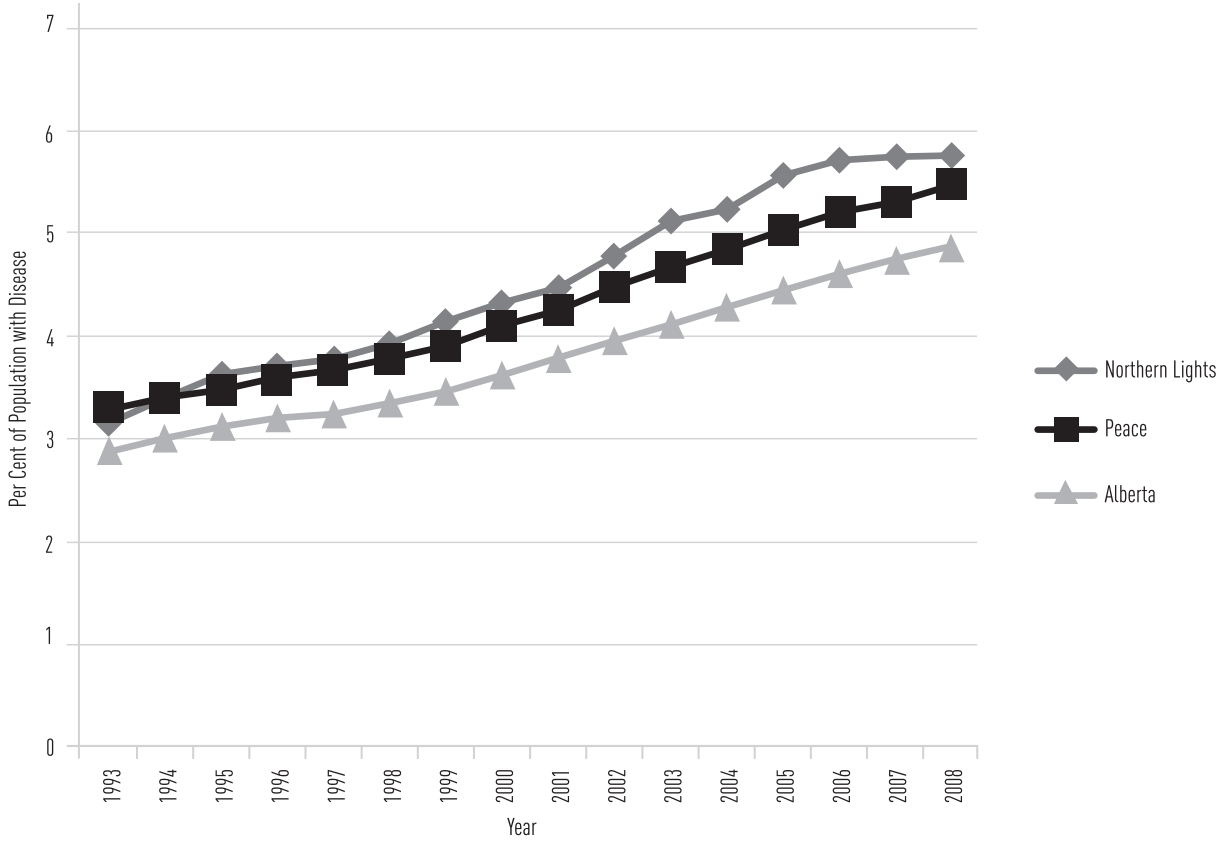
In Figures 10.4 and 10.5, the highest prevalence and incidence rates for diabetes is consistently in the Northern Lights followed closely by Peace Country. The Alberta Diabetes Surveillance System report in 2010 concludes: "*Diabetes is much more common among the Status Aboriginal population, as incidence and prevalence rates are twice as high in both males and females compared to the general population*" (ADSS 2010). Even if prevalence and incidence rates for diabetes in Northern Lights are higher than the provincial average, mortality rates remain lower (see Section 10.1.2). Because the Status Aboriginal population currently represents about 10% of Northern Lights' total and has steadily decreased in proportion over the last 15 years, this cannot explain the 50% raise in diabetes prevalence over the last 10 years.

Figure 10.4 Age-adjusted incidence rate of diabetes (from 1993 to 2007)



Source: AHW 2010b

Figure 10.5 Age-adjusted prevalence rate of diabetes (from 1993 to 2008), % of population with disease



Source: AHW 2010b

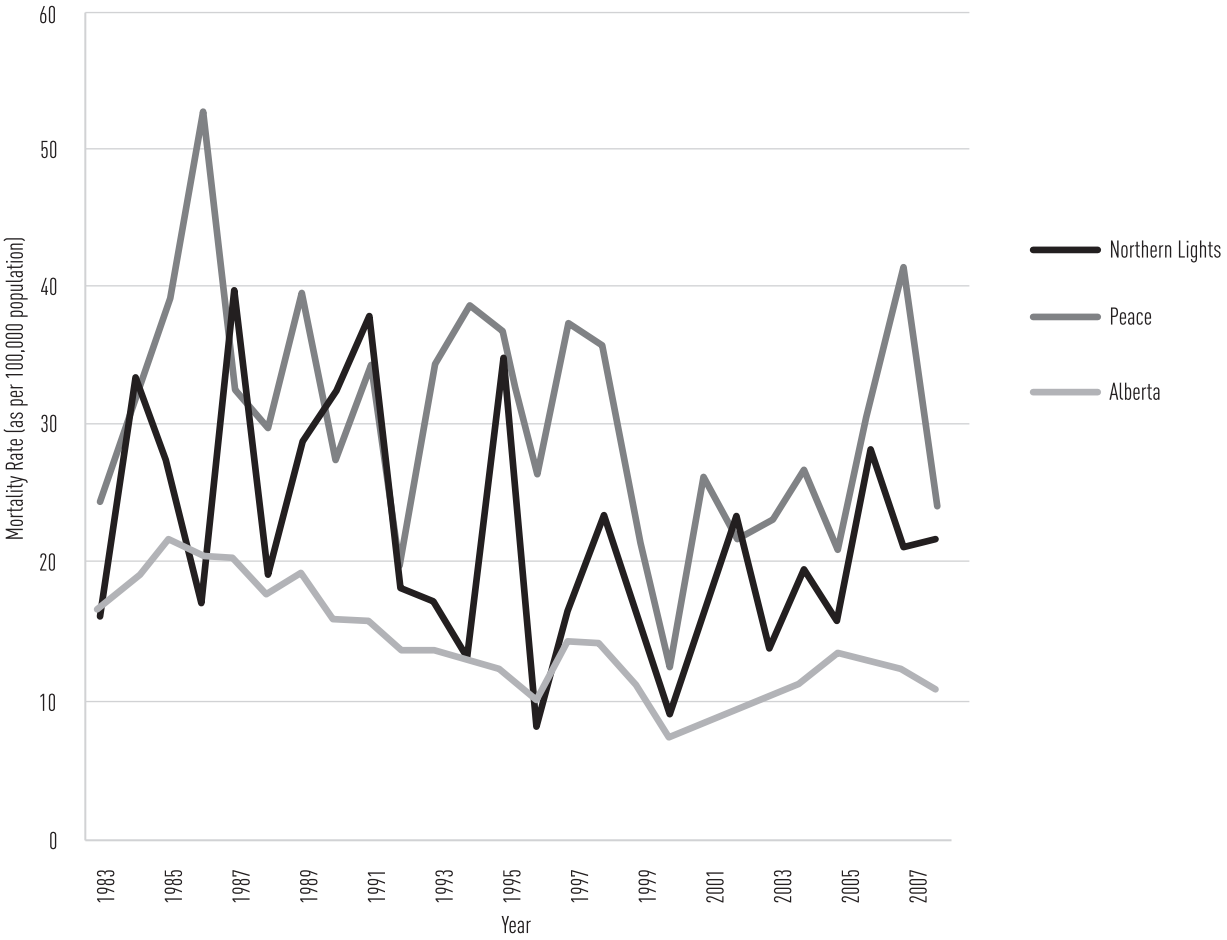
10.2.3 Mortality Rates for Motor Vehicle Accidents

In Alberta, it is reported that most motor vehicle collision deaths involve teenagers and young adults, and that higher mortality rates are seen in rural regions. Alcohol is a well-documented risk factor for motor vehicle collisions (AHW 2010a). In Figure 10.6, the mortality rates for motor vehicle accidents are shown to be higher in Northern Lights and Peace Country (AHW 2010a).

Police reported that 7% of all fatalities on Alberta highways in 2007 occurred on Highway 63 between Redwater and Fort McMurray, illustrating the dramatic impact of the traffic overloading on the only highway access to Fort McMurray although no comparisons were provided concerning traffic volume or proportion of total miles driven.[18] The Alberta and Federal governments agreed in 2006 to the cost-sharing of a $320 million investment to twin a 146 km portion of Highway 63 to improve road safety.[19] This was an initial commitment towards the ultimate $680 million cost of twinning all 240 km of Highway 63.

[18] http://edmonton.ctv.ca/servlet/an/local/CTVNews/20081025/edm_highway63_feature_081025/20081027/?hub=EdmontonHome
[19] http://www.infc.gc.ca/media/news-nouvelles/csif-fcis/2006/20060829fortmcmurray-eng.html

Figure 10.6 Age-standardized mortality rates by motor vehicle accident from 1983 to 2008



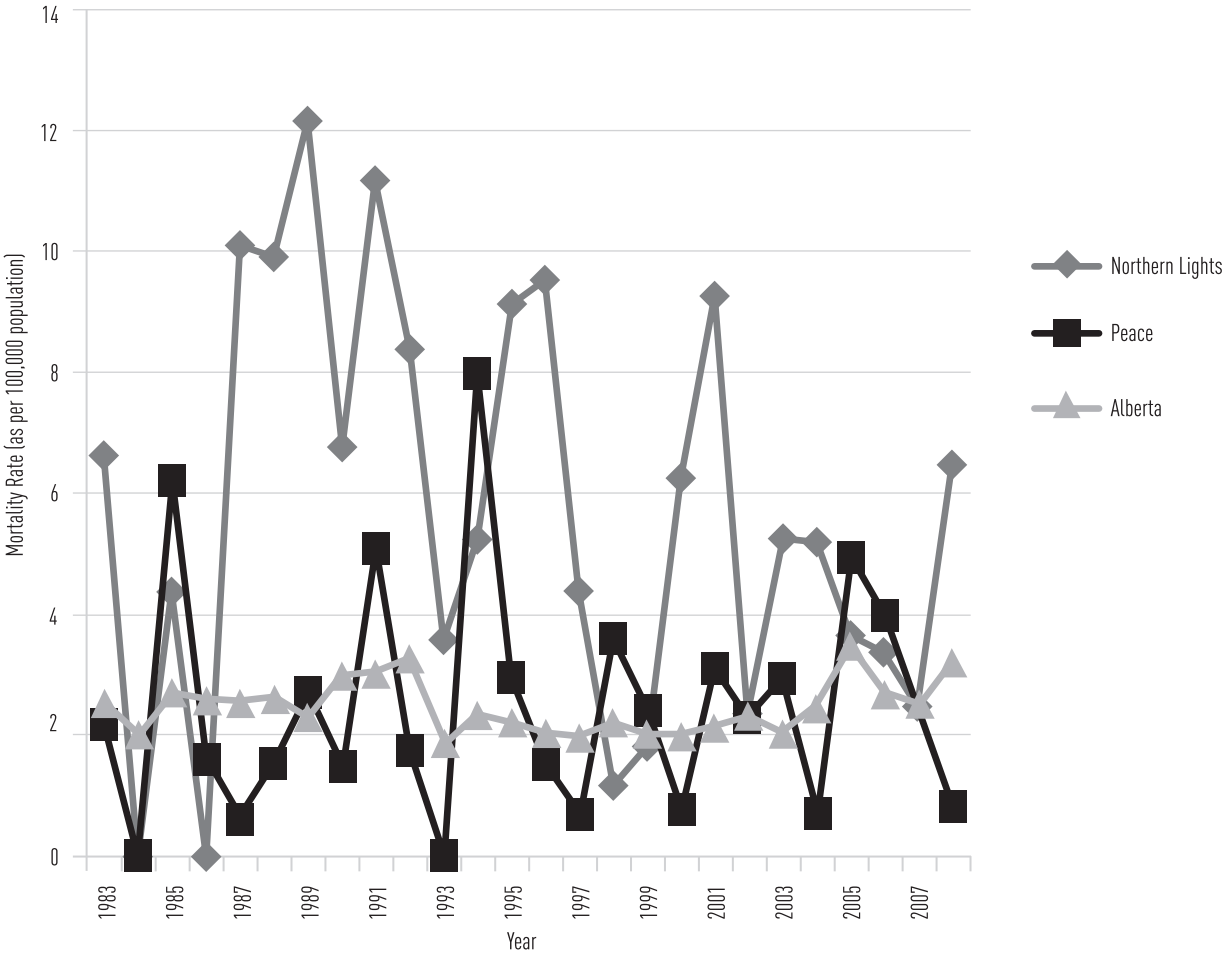
Source: AHW 2010b

10.2.4 Mortality Rates for Homicide (Assault)

In 2005, the age-standardized mortality rate for homicide in Canada was 1.9 (Statistics Canada 2010). For Northern Lights, in 2005, the rate was 3.65, almost equal to Alberta's rate of 3.48 (AHW 2010a).

According to Figure 10.7, covering the period 1998-2007, the rate is clearly higher for Northern Lights, despite the obvious fluctuations from rates calculated with small numbers.

Figure 10.7 Age-standardized mortality rates by homicide (assault) from 1983 to 2008



Source: AHW 2010b

10.2.5 Behavioural Risk Factors

Behavioural risk factors are behaviours and conditions that are linked with the leading causes of death such as heart disease, cancer, diabetes, and injury. Examples of these behaviours and conditions include: not getting enough physical activity, being overweight, and using tobacco or alcohol (CDC 2010).

10.2.5.1 Physical Activity and Self-Reported Health Status

Leisure-time physical activity is a key behaviour affecting the health of individuals. Higher levels of physical activity reduce the risk of heart attack, obesity, other diseases, and stress (HRSDC 2010). In 2009, 53.5% of Albertans were classified as moderately active to active. Northern Lights had a substantially lower level of physical activity at 38.7% than the provincial average, using the definition of the Canadian census (Statistics Canada 2009).

The self-rated health indicator measures an individual's perception of his or her overall health. It is considered a predictor of real health status, as it takes into account factors such as the existence of

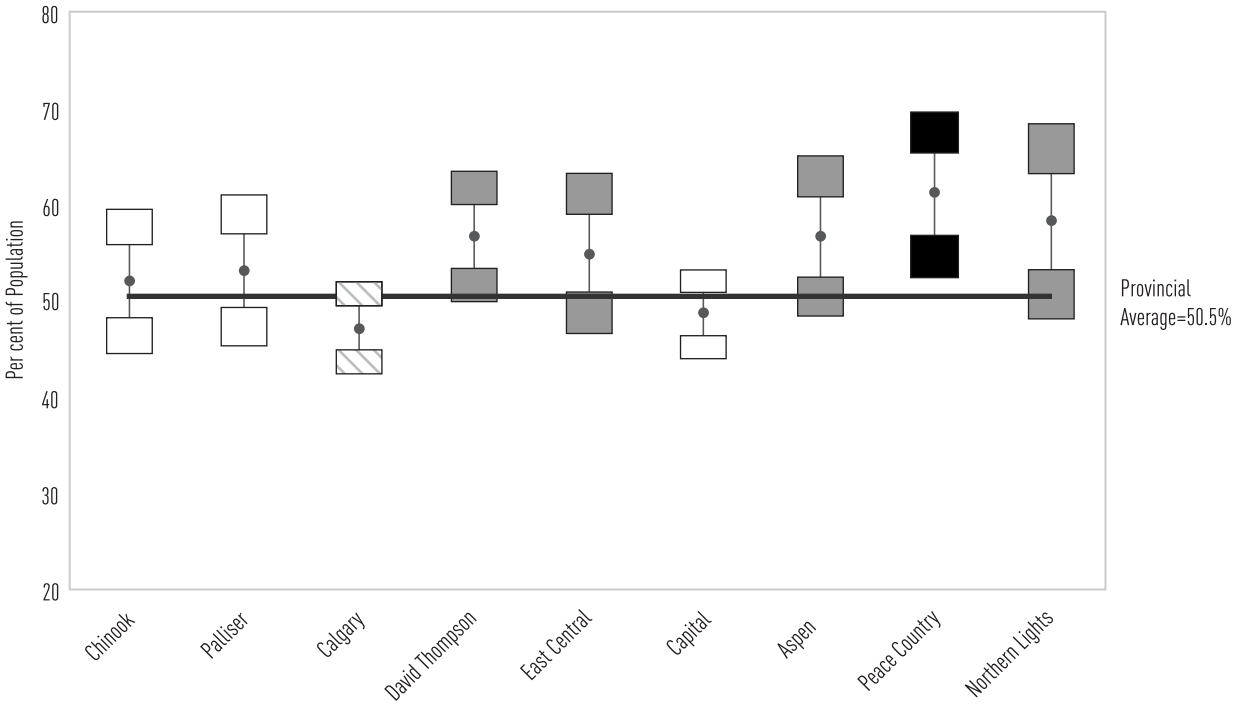
disease and its severity (HRSDC 2010). “Very Good” to “Excellent” self-rated health status was reported for a majority of residents (63.4%) in Northern Lights, in 2009, equal to the provincial average (63%) (Statistics Canada 2009).

10.2.5.2 Obesity

Obesity is a risk factor for many chronic illnesses, particularly heart diseases and diabetes (HRSDC 2010). In Figure 10.8, for 2005, the highest Alberta proportion of overweight and obese adults occurred in the Peace Country, Northern Lights, and Aspen regions with percentages above the provincial average.

Statistics Canada reports 28.9% of the population in Northern Lights as being obese compared to 18.3% for the rest of Alberta. The obesity criteria are based on Health Canada guidelines for body weight classification using a body mass index, or BMI, of 30 and over (Statistics Canada 2009).

Figure 10.8 Regional differences in overweight and obesity, 2005



Legend: In the figure, the black dot represents the value of the rate for each region. The colour of the bars above and below the dot represents the score of the region (based on standard error) which measures proximity to provincial average.
■ = higher, ■ = probably higher, □ = average, ▨ = probably lower, ▨ = lower.

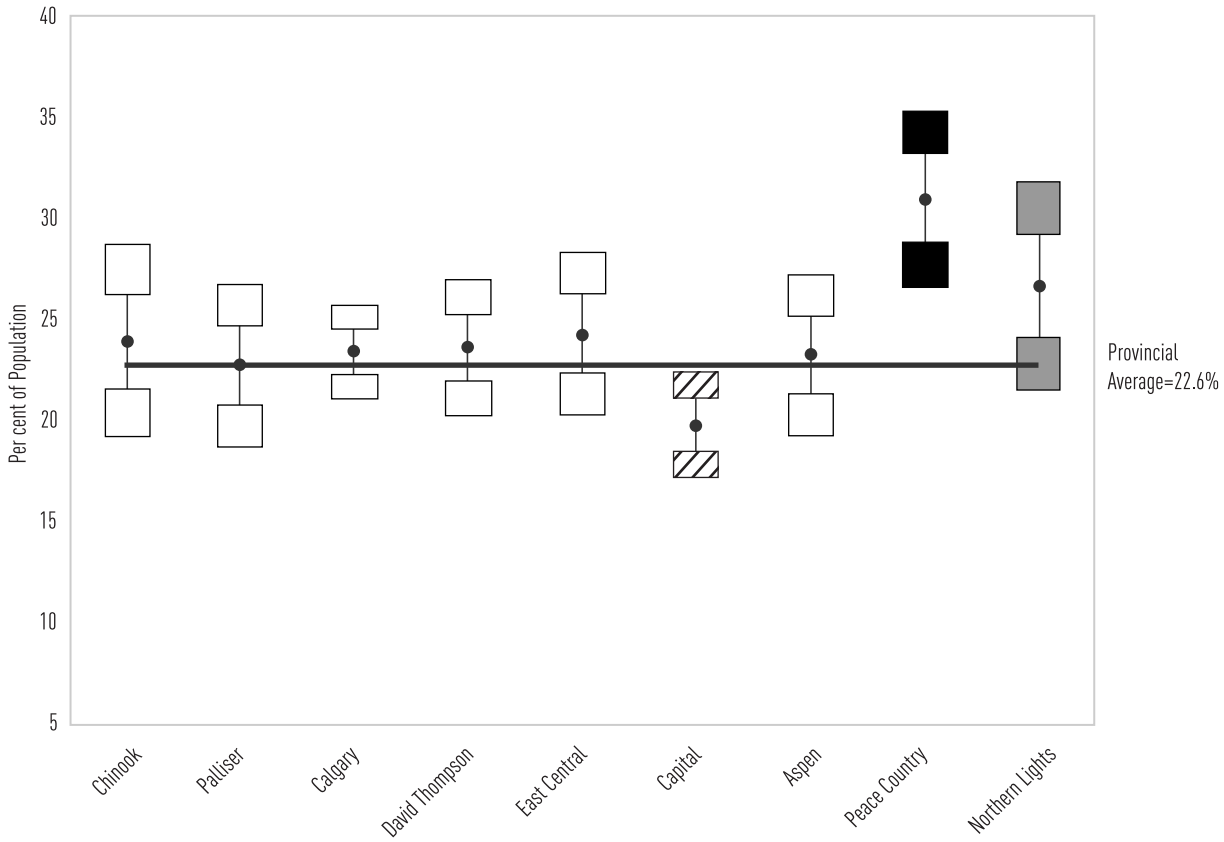
Source: AHW 2007b

10.2.5.3 Heavy Drinking and Smoking

Heavy drinking refers to having consumed five or more drinks per occasion, at least 12 times a year. Alcohol consumption can have serious health and social consequences, especially when combined with

other behaviours such as driving while intoxicated.The highest percentage of heavy drinkers in Alberta is in the 20–24 year age range. The percentage of heavy drinkers decreases with increasing age for both sexes. In Figure 10.9, Peace Country had the highest percentage of heavy drinkers followed by Northern Lights compared to the Alberta average in 2005 (AHW 2007b).

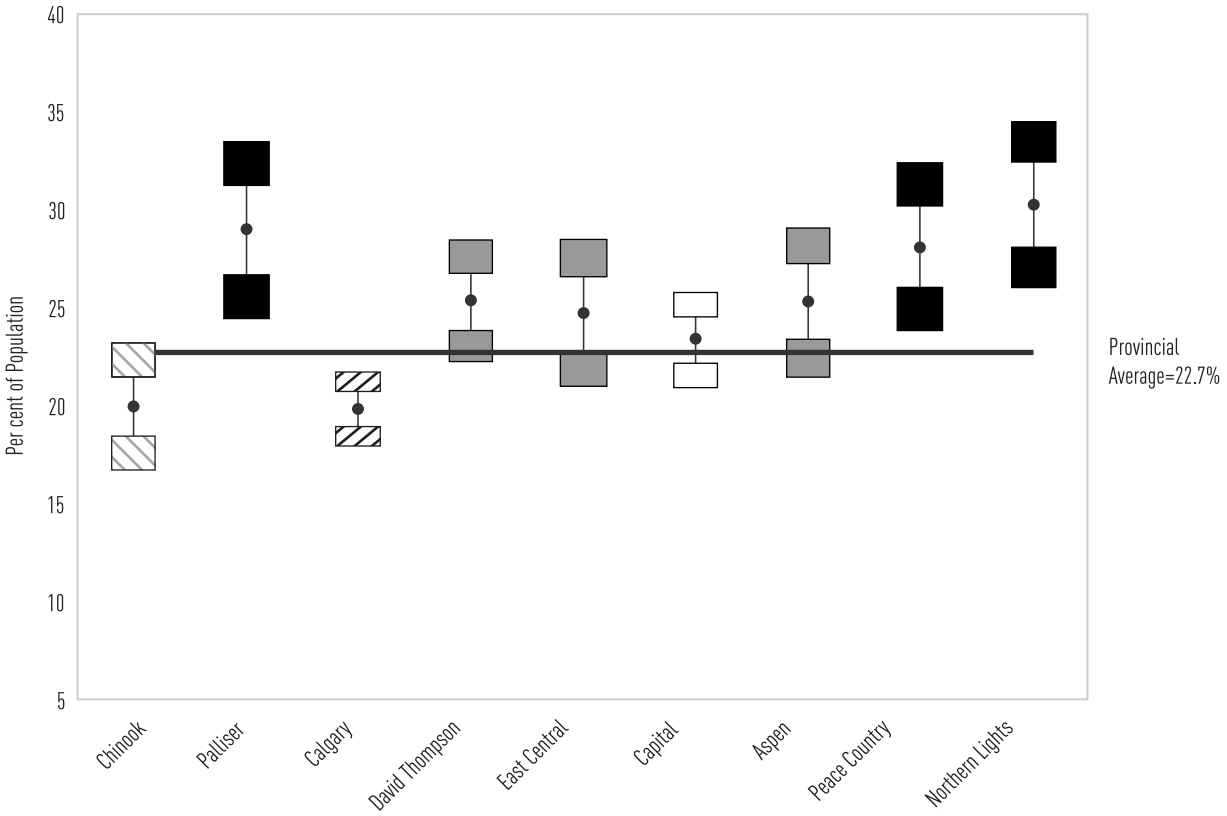
Figure 10.9 Regional differences for heavy drinkers, 2005



Source: AHW 2007b; for legend, see Figure 10.8

Smoking is recognized as a major risk factor for lung cancer, respiratory diseases, and other health problems (HRSDC 2010). As shown in Figure 10.10, the Palliser (southeastern Alberta, agricultural, rural), Peace Country (northwestern Alberta, forestry, oil and gas, some agricultural), and Northern Lights regions had a smoking rate higher than the provincial average (AHW 2007b).

Figure 10.10 Regional differences in smoking, 2005



Source: AHW 2007b; for legend, see Figure 10.8

10.2.6 Mental Health

Both physical health and mental health determine a person's overall health. Good mental health is now regarded as not only the absence of mental illness such as mental disorders, emotional problems, or distress, but also the presence of factors such as the ability to enjoy life, balance, and flexibility (HRSDC 2010).

10.2.6.1 Perceived Mental Health

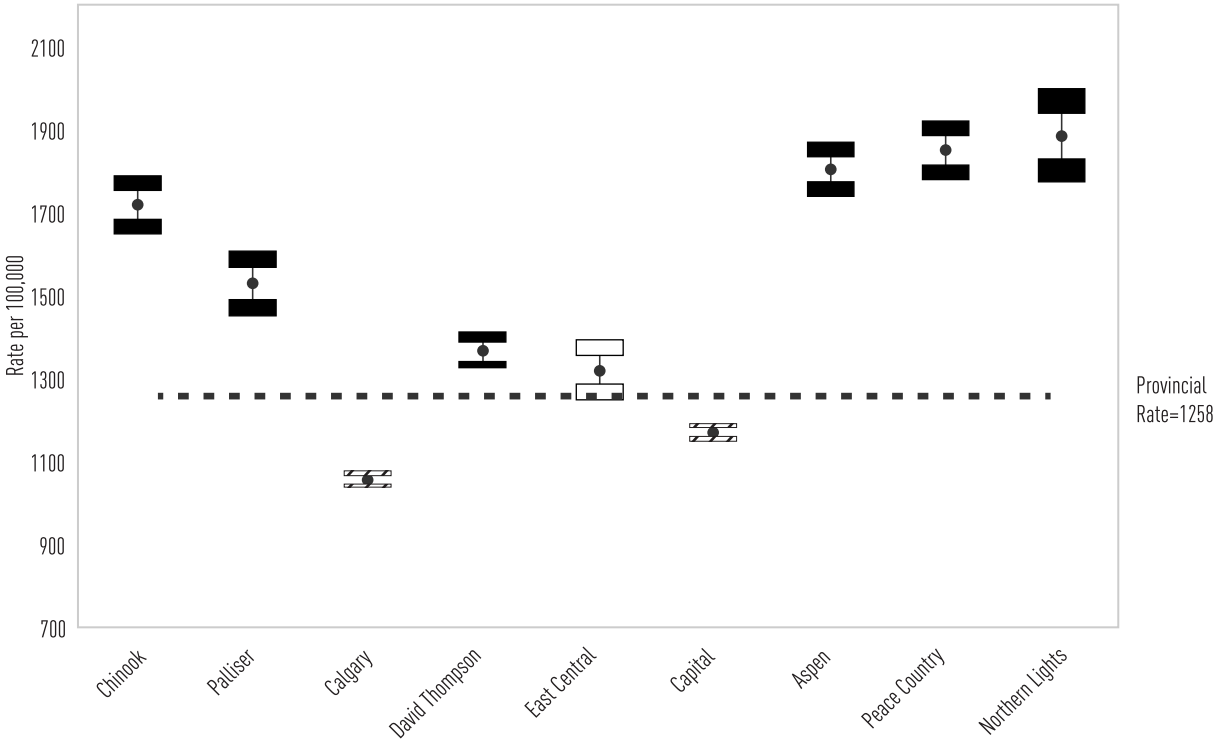
Perceived mental health provides a general indication of the population suffering from some form of mental disorder, mental or emotional problems, or distress, not necessarily reflected in perceived health. The population aged 12 and over who reported perceiving their own mental health status as being excellent or very good was 72.7% in Northern Lights essentially equivalent to 73.7% in Alberta (Statistics Canada 2009).

10.2.6.2 Substance-Related Disorder

This disorder is characterized as the inappropriate use of psychoactive substances that can lead to dependence. All health regions had a higher rate than the provincial average for physician claims for substance-related disorders except Capital Health Authority (Edmonton region) and Calgary Health Region. This showed a remarkable pattern of higher rates outside the major urban areas (Figure 10.11).

It is pointed out in the Alberta Health report that regional variation is likely due to the different services available in different regions (AHW 2007b). All things being equal, the low availability of medical personnel in Northern Lights would logically suggest lower reporting from overburdened staff. This circumstance is not likely to explain that rate being so much higher (rather than lower) than the provincial average (see Section 10.2.9 for more details).

Figure 10.11 Regional differences for substance-related disorders, 2004–06



Source: AHW 2007b; for legend, see Figure 10.8

10.2.6.3 Sense of Community Belonging

Research shows a high correlation of sense of community-belonging with physical and mental health (Statistics Canada 2009). The population aged 12 and over who reported their sense of belonging to their local community as being very strong or somewhat strong was 51.6% in Northern Lights while it was 60.5% in Alberta (Statistics Canada 2009).[20]

10.2.7 Income Levels, Housing, and Employment

10.2.7.1 Income Levels

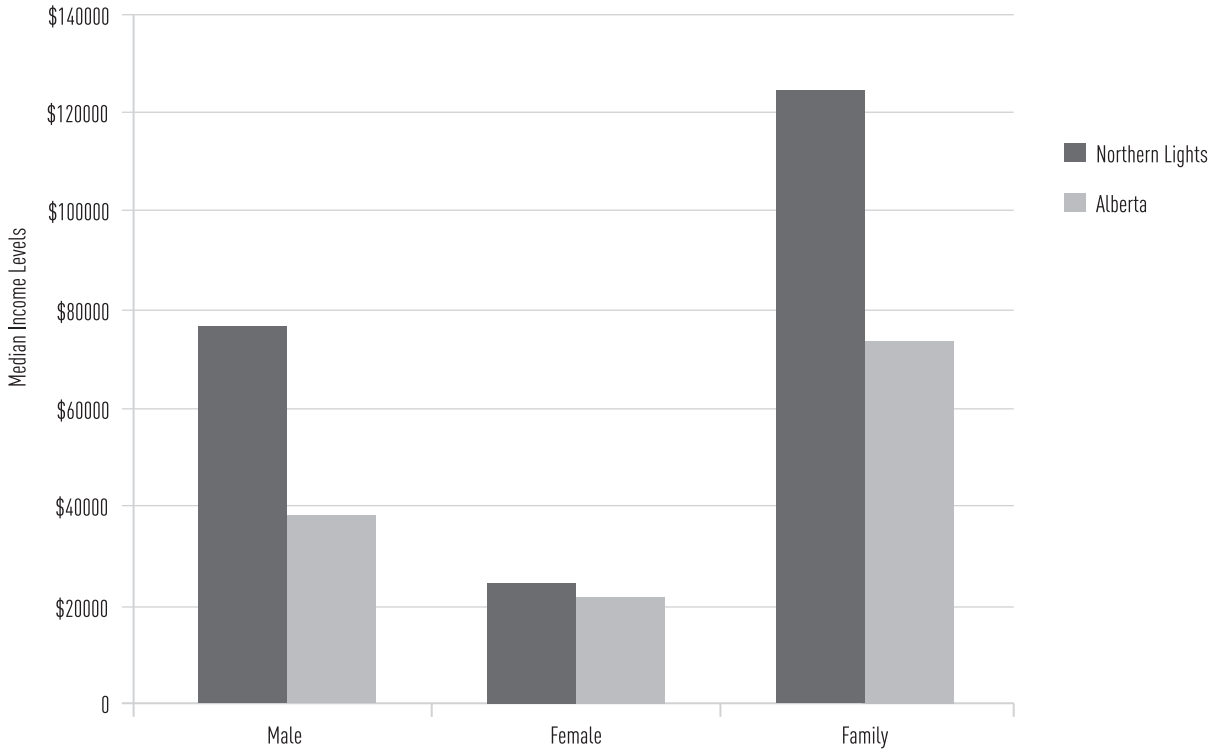
Higher income is often associated with better health but a plateau in the benefit of higher income is reached without further health improvement evident at higher incomes: "*...the relationship between*

[20] Statistics Canada uses coefficients of variation to classify the reliability of its data for all its surveys. Coefficients of variation (CV) are categorized as follows: CV ≤ 15%: sufficiently precise estimates; CV between 15% and 25%: acceptable precision, estimates to be carefully interpreted; CV > 25%: low precision, estimates to be interpreted with circumspection. For this case, the CV is in the first category, sufficiently precise estimates.

income and life expectancy is steeply linear up to a level of about $5,000 Gross National Product per capita (GNPpc; 1996 data). Beyond this point (that is to say, among developed countries), further increments to GNP make little difference to life expectancy, and the curve appears to plateau" (Wilkinson 1996). In 2006, the median income for couple families in the RMWB was estimated at $124,592, compared to the Alberta median family income of $73,823 (Figure 10.12). Male median income in RMWB was estimated at $76,645, twice the Alberta median income for men at $38,220. The female median income was much lower than the male in RMWB at $24,452, which is much closer to the Alberta median income for women at $21,753 (Statistics Canada 2007). This discrepancy suggests that it is predominantly males who are beneficiaries of higher paying employment in oil sands development.

According to Alberta Finance and Enterprise: "*Average weekly earnings (including overtime) in Alberta's oil and gas industry rose 24% between 2000 and 2007 to $1,700, a level that is nearly double the Alberta average. For the oil sands industry, difficulty attracting labour to the region was exacerbated by the relatively remote location and the need for specialized trades, which were already in short supply*" (AFE 2009).

Figure 10.12 Median income levels (before tax) in 2005



Source: Statistics Canada 2007

10.2.7.2 Housing

Housing or lack of adequate housing (overcrowding, substandard dwellings, homes requiring significant repairs, homelessness, etc.) contributes to increased stress, morbidity, mortality, social exclusion, and physical and mental illness (SSPH 2009). Housing cost, the largest and perhaps least

flexible component of a household budget, is also an important factor in the financial security of households (HRSDC 2010).

In 2005, Fort McMurray had the highest house prices in Alberta. Information from the Oil Sands Developers Group indicates that in 2008, the average rental price of a two-bedroom apartment was around $2,300 per month, and the average cost of a single-family home was more than $682,000. In comparison, the average rental price of a two-bedroom apartment in Calgary was $1,148, and a typical single-family home cost an average of $405,000 (OSDG 2009).

10.2.7.3 Employment

Employment and working conditions have a significant effect on a person's physical and mental health. Earned income provides not only money, but also a sense of identity and purpose, social contacts, and opportunities for personal growth. Unemployment, sporadic employment, or low-wage employment can lead to poorer health (SSPH 2009).

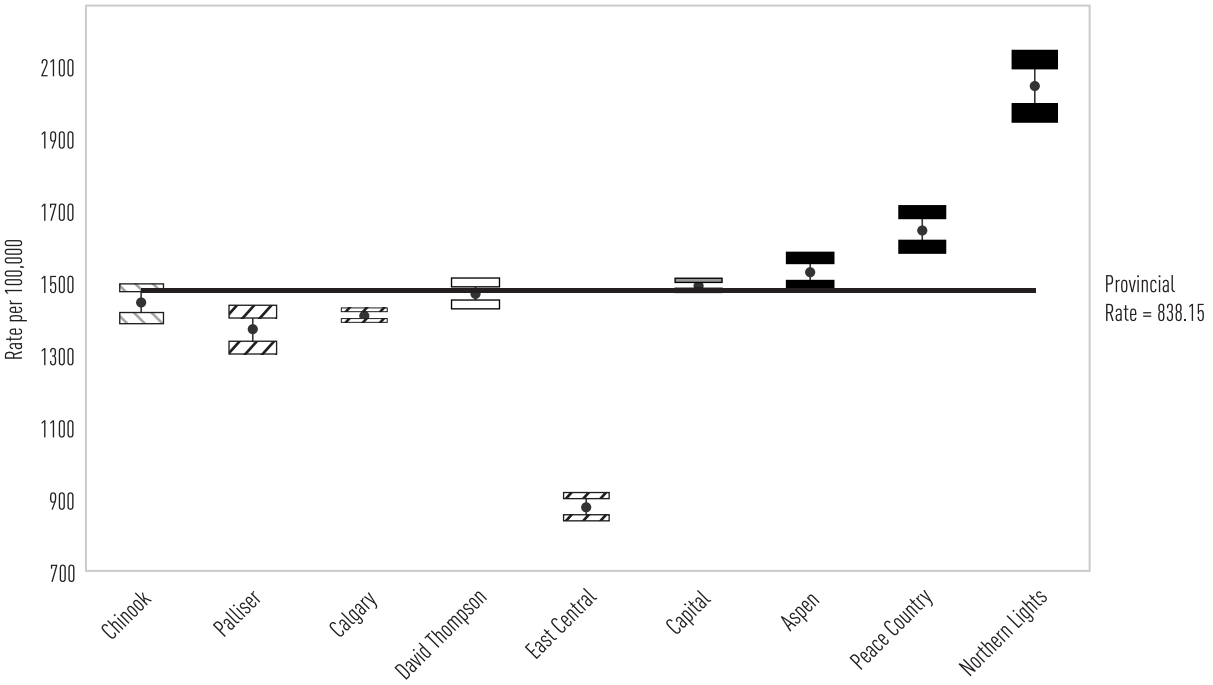
In 2006, the employment rate which refers to the number of persons employed in the week, expressed as a percentage of the total population (15 years and over), was 79% for RMWB versus 70.9% for Alberta. The unemployment rate at that time was 4.3% in Alberta and 4% in RMWB in 2006 (Statistics Canada 2007).

10.2.8 Incidence Rates for Infectious Diseases

10.2.8.1 Sexually Transmitted Infections (STIs)

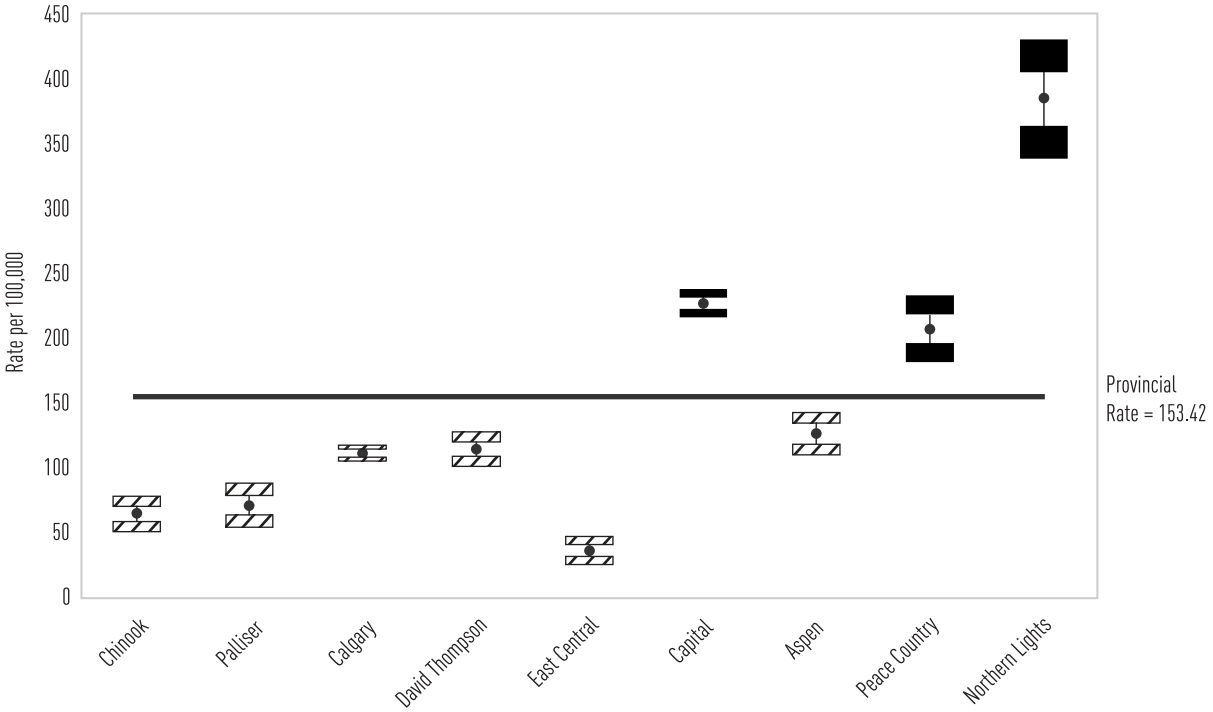
The rates of chlamydia and gonorrhoea are higher in the northern half of the province, particularly in the Northern Lights region, as shown in Figures 10.13 and 10.14.

Figure 10.13 Regional differences in incidence of chlamydia, 2004–06



Source: AHW 2007b; for legend, see Figure 10.8

Figure 10.14 Regional differences in incidence of gonorrhea, 2004–06

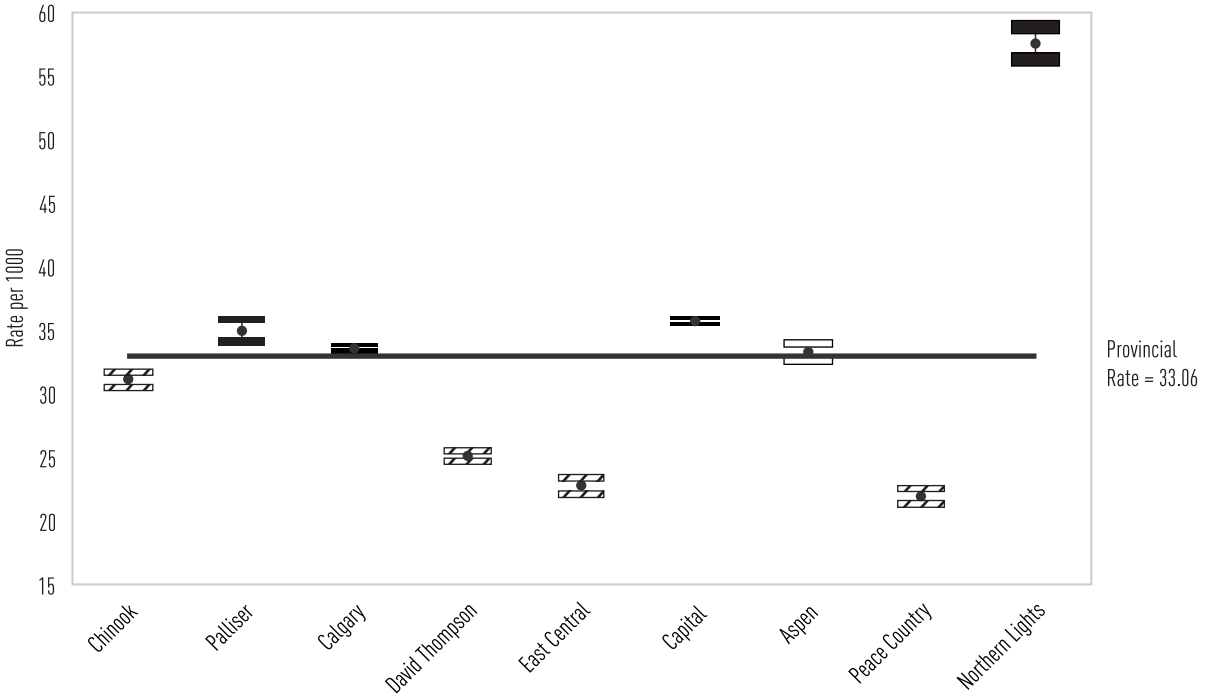


Source: AHW 2007b; for legend, see Figure 10.8

10.2.8.2 Other Infectious Diseases

Influenza. From 2004 to 2006, the Northern Lights Health Region had an influenza incidence rate much higher than the provincial average, as shown in Figure 10.15. The incidence of influenza in Northern Lights is almost double the provincial rate and is uniquely high among health regions in Alberta. The reasons for this difference are not obvious, and this clearly deserves attention.

Figure 10.15 Regional differences in incidence of influenza, 2004–06



Source: AHW 2007b; for legend, see Figure 10.8

10.2.9 Health Care System Characteristics

The ratio of physicians to population reflects the number of doctors in a region. The extent to which this affects individual regions is likely to vary. This ratio is just one measure of population need and physician supply. No authority has yet defined the ideal physician to population ratio but it is generally assumed that areas with a low ratio could benefit from additional physicians.

The health care system is one contributor to population health, but it is estimated to account for only 25% of health outcomes regardless of the level of funding it receives (SSPH 2009).

The availability of doctors is much lower outside Calgary and Edmonton, but the Northern Lights region has the lowest of comparably-sized centers and the lowest in the north. Fort McMurray has 71 general practitioners per 100,000 of population, compared with Peace Country at 78 and East Central at 85 (Table 10.2). Alberta overall has more general practitioners per unit population than the Canadian average.

Table 10.2 Family and specialist physicians in 2007 (Rate per 100,000, 95% CI)

	Canada	**Alberta**	**Northern Lights**	**Peace Country**	**East Central**
General family physicians	99 (CI:98–100)	108 (CI:105–112)	71 (CI:52–90)	78 (64–93)	85 (68–101)
Specialist physicians	94 (CI:93–95)	90 (CI:87–93)	15 (CI:7–24)	27 (18–35)	11 (5–17)

Source: Canadian Institute for Health Information 2009

There is some probability of under-notification for several diseases in NLHR caused by the limited medical workforce.

10.2.10 Conclusions on Public Health Profile

The comparison of the health status of residents of Northern Lights with residents of Alberta provides some interesting perspectives on health conditions across the region. Since the provincial average is dominated by Calgary and Edmonton which comprise about 60% of the provincial population, comparisons were also provided with some other less urban health regions such as Peace Country.

Data tend to show that health status in Northern Lights is worse than the provincial average for several indicators such as substance-related disorders, heavy drinking and smoking, sexually transmitted infections, obesity, prevalence of diabetes, and mortality rates due to homicide as well as mortality rates due to motor vehicle collisions. Furthermore, Northern Lights Region has the lowest availability of doctors. These indicators are typical of a boom town.

Several of the health determinants are worse outside of Calgary and Edmonton, but in many cases Northern Lights is the worst or among the worst of the other health regions. There are some incongruities in the data such as the fact that Northern Lights Region has the highest incidence and prevalence rates for diabetes but at the same time it has lower than average mortality rates for diabetes. As well, Northern Lights Region has smoking and heavy drinking rates higher than the provincial average and yet it has lower incidence and mortality rates than provincial averages for lung cancer, respiratory diseases, and other chronic illnesses (such as liver cancer).

The problems associated with the different numbers for the total population depending on the source have already been mentioned. Another major confounder mentioned earlier is the eligibility for Alberta Health Services average (residency duration of three months) which may lead temporary workers to be treated for medical problems in their province of origin and to be counted as being residents of their province, thus underestimating actual rates for chronic diseases in Alberta.

Even if there are clearly trends that are worse in Northern Lights, some economic aspects are better in this region-to-region comparison, such as employment and income, but some are worse, such as housing costs.

10.3 Alberta Government Role in Public Health and Environment

In Alberta, public health is the responsibility of the Ministry of Health and Wellness (AHW). The Public Health Division coordinates health surveillance, disease control and prevention, and population health strategy development. Until 2008, in the oil sands regions, health services were coordinated and delivered through the Northern Lights Regional Health Authority in the Fort McMurray area, the Peace Country Health Region in the Peace River area, and the Aspen Health Region in the Cold Lake area.

Public health surveillance activities including monitoring the health status of the population and providing information for planning, implementing, and evaluating health strategies are the responsibility of the Division of Public Health of Alberta Health and Wellness which conducts regular monitoring of chronic and acute diseases to identify potential outbreaks or problem areas.

In May 2008, all Regional Health Authorities (RHAs) were replaced by the provincial governance board. Alberta Health Services (AHS) is now responsible for health services delivery for the entire province and reports to a governing Board accountable to the Minister of Health and Wellness (AHW 2008). Prior to this reform, the public health functions of RHAs were: promoting and protecting the health of the population in the health region, disease and injury prevention, and ongoing assessment of the health needs of the population. RHAs were also required to meet provincial public health targets established for various health indicators.

RHAs used to deliver environmental health programs that monitored, inspected and enforced safe food practices, water and air quality, and safe sewage management. Since 2008, environmental health in the oil sands regions has the responsibility of the North Zone of AHS and the Fort McMurray Environmental Health office provides the environmental health program services to the Regional Municipality of Wood Buffalo. The Public Health Division of Alberta Health and Wellness has performed community exposure assessments to provide measures of potential exposure to environmental contaminants.

10.4 Possible Major Health Impacts of Oil Sands Development

In this section, the intention is to give a brief overview of possible major health impacts that were created by oil sands projects to date. The number of available studies and data relating health and oil sands development was very limited at the time of the literature search (see Appendix A9). Since studies concerning beneficial impacts were not found, this section focuses on adverse health impacts with a brief section on beneficial impacts at the end. The aim is to discuss how oil sands projects may induce unintended changes in health determinants that may result in changes in health outcomes.

In order to identify clearly the major health concerns raised by the project, they were separated in two categories: (1) Effects caused by environmental changes and exposure conditions and (2) Effects on community health (including boom-town effects and effects on health care services).

10.4.1 Effects Caused by Environmental Changes and Exposure Conditions

This section focuses on the release of contaminants by waste and residue management practices and the human exposure pathways (water, air, food) by which the local population comes into contact with the contaminants and may experience health effects. Expected changes in human exposures and the effects of projects on total human exposures are examined as well.

The population distribution in RMWB is relevant to assessment of human exposure (Figure 10.2, Table 10.3). The only year-round community within the surface mining region of the oil sands is Fort McKay. Fort Chipweyan is 150 km downstream from Fort McKay (with respect to the flow of the Athabasca River) on the northwest corner of Lake Athabasca opposite the Athabasca River Delta on the south shore (Figures 3.3, 10.2). Fort McMurray is 50 km south (upstream on the Athabasca River) from the original Suncor oil sands operation at Tar Island. Anzac is about 20 km south of Fort McMurray.

Table 10.3 2009 Population in RMWB, total population 89,950

	Permanent	**Shadow (resident for more than 30 days / year)**	**Official Population**
Urban service area Fort McMurray	62,589	1,087	63,676
Rural service area, including Fort McKay and Fort Chipweyan	4,159	22,115 (industry work camps)	26,274

Source: Alberta Municipal Affairs 2010

The distribution of First Nation populations is summarized in Table 10.4. The First Nations communities closest to the surface mining and bitumen extraction plants are the Fort McKay First Nation which is surrounded north and south by oil sands mines, and bitumen extraction and upgrading facilities and the Athabasca Chipewyan First Nation which has some reserve lands far enough south of Fort Chipewyan to be approaching new oil sands developments north of Fort McKay.

The population distribution shows that very dramatic health effects would have to occur in the much smaller rural service area population to show up as overall changes in the rates for the entire population of RMWB. The high proportion of work camp residents, most of whom are transient, will not be coded to Northern Lights in available databases which makes it even more difficult to determine local health impacts.

Table 10.4 2010 Population of First Nations of the Athabasca Tribal Council

		Population		
First Nation	**Location**	**On Own FN Reserve**	**Off Any FN Reserve**	**Total Registered with INAC**
Athabasca Chipewyan FN	Fort Chipewyan south of Lake Athabasca	10	677	905
Chipewyan Prairie FN	Chard 100 km south Fort McMurray	343	370	718
Ft McKay FN	Fort McKay 70 km north Fort McMurray	333	323	668
Ft McMurray FN	immediately south of Fort McMurray	256	357	621
Mikisew Cree FN	Fort Chipewyan north of Lake Athabasca	147	1818	2592

Source: INAC 2010

10.4.1.1 Water Exposure

The extraction of bitumen from the oil sands generates large volumes of process-affected waters containing elevated levels of NA, salinity, and PAH (Dixon et al. 2010). However, the critical issue for human health is what exposure routes are active for contaminants to reach human populations.

A recent study by researchers at the University of Alberta focused on polycyclic aromatic compounds (PACs) (Kelly et al. 2009). The research team monitored concentrations of PACs in water and snow packs at numerous sites along the Athabasca and its tributaries in the winter and summer of 2008. PACs are compounds which contain more than one aromatic ring (i.e., benzene consists of a single aromatic ring) which can be joined into structures containing multiple rings. PAHs are a subset of PACs that consist only of carbon and hydrogen, whereas PACs also contain other elements and/or heterocyclic structures (carbon rings containing sulphur, nitrogen, or oxygen). The PACs Kelly et al. found were dominated by homologues of three-ringed alkyl phenanthrenes, alkyl dibenzothiophenes, and alkyl fluorenes.

The U.S. EPA has provided toxicology assessments on 14 PAHs with three or more rings and seven of these have been classified B2, "*probable human carcinogens*" (Table 10.5) all of those are four- or five-ring PAH compounds. The B2 classification means that the U.S. EPA determined that there was no or inadequate evidence for the compound causing cancer in humans, but there was adequate evidence for the compound causing cancer in experimental animals. Approximately 75% of the PACs collected by Kelly et al. (2009) at locations with medium to large scale industrial activity by water sampling with polyethylene membrane devices (PMDs) which collect only water-soluble PACs were

"*three-ring PAC dominated by alky-substituted dibenzothiophenes, phenanthrenes/anthracenes and fluorenes*" (Kelly et al. 2009). None of these classes of PACs are classified as carcinogens. The proportion of the remaining 25% of total PACs that were carcinogens, or alkyl-derivatives of carcinogens, was not specified and no data was presented by Kelly et al. (2009) for those PACs, like benzo-[a]-pyrene, that have been classified as carcinogens.

Table 10.5 Classification of PAHs for carcinogenicity

PAH Compound	**Number of Rings**	**Carcinogenic Classification**	**Quantitative Cancer Risk Slope Factor**
Acenaphthylene	3	D – not classifiable	NA
Anthracene	3	D – not classifiable	NA
Benz[a]anthracene	4	B2 – probable human carcinogen	No
Benzo[a]pyrene (BaP)	5	B2 – probable human carcinogen	7.3 $[mg/kg\text{-}d]^{-1}$
Benzo[b]fluoranthene	5	B2 – probable human carcinogen	No
Benzo[g,h,i]perylene	6	D – not classifiable	NA
Benzo[k]fluoranthene	5	B2 – probable human carcinogen	No
Chrysene	4	B2 – probable human carcinogen	No
Dibenz[a,h]anthracene	5	B2 – probable human carcinogen	No
Fluoranthene	4	D – not classifiable	NA
Fluorene	3	D – not classifiable	NA
Indeno[1,2,3-cd]pyrene	6	B2 – probable human carcinogen	No
Phenanthrene	3	D – not classifiable	NA
Pyrene	4	D – not classifiable	NA

NA = not applicable because this PAH is not classifiable as being carcinogenic

Source: USEPA 2010; IRIS Database

Kelly et al. (2009) reported that the highest concentrations of total PACs encountered near industrial activities (0.682 µg/L) were similar to concentrations (as low as 0.4 µg/L) reported to be toxic to fish embryos (Carls et al. 1999), based on studies of PAHs from weathered crude oil.

The highest levels were found within 50 km of two major oil sands upgraders. This study rejects a claim attributed to industry and government that pollution is caused by naturally occurring seepage from the oil sands deposits. Potential human health exposure pathways would occur from water consumption and from eating the compounds in fish. Kelly et al. (2009) found that dissolved PACs did not persist as far as the Athabasca River Delta and Fort Chipewyan. The direct water consumption exposure routes being limited, health effects are not expected from that route of exposure in Fort Chipewyan, but residents of Fort McKay are within the region of slightly elevated contamination. Downstream water quality issues are discussed in Section 8.4.

10.4.1.2 Air Exposure

It is important to state as an introduction to this section, that air quality in Alberta is considered generally good, including air quality in Northern Alberta (Kindzierski and Ranganathan 2006; Guidotti 2009; Kindzierski et al. 2010). A 2010 report by the School of Public Health of the University of Alberta concerning behaviours and trends in outdoor air quality, between 1998 and 2007, in Northern Alberta, concluded that there has been little or no pattern of changes in concentrations of major air pollutants across the oil sands region over the past 10 years (Kindzierski et al. 2010).

Data collected over several years seem to confirm that conclusion too. For example, levels of fine particulate matter ($PM_{2.5}$), a contaminant of concern which may cause broad effects to the respiratory and cardiovascular systems, show that the five year average in Fort McMurray is relatively low. The level is below the Canada-wide Standard for $PM_{2.5}$ levels, which is established at 30 $\mu g/m^3$ averaged over 24 hours, as per the AENV ambient air quality objective (Environment Canada 2004; AENV 2009). Levels measured were also below the WHO guideline for $PM_{2.5}$ set at 25 $\mu g/m^3$ 24-hour mean (WHO 2006). For a five-year period, from 1998 to 2003, Fort McMurray experienced only two days in exceedance of the Canada-wide Standard for $PM_{2.5}$.

Table 10.6 shows different North American cities that are compared by looking at the differences in their annual averages over a five-year period, from 1998 to 2003, and their most recent annual averages in 2003 for $PM_{2.5}$. Fort McMurray's five-year average was 5.4 $\mu g/m^3$ while the average in 2003 was 3.4 $\mu g/m^3$. Note that each city did not necessarily have the same number of stations, which may affect the average for a given city. Fort McMurray has only two monitoring stations compared with four in Calgary and five in Edmonton.

Table 10.6 Annual average fine particulate concentrations in North American cities ($\mu g/m^3$)

City/County	**5 Year Average (1998–2003)**	**2003**
St. John's	5.1	4.9
Montreal	8.3	8.2
Quebec	8.6	8.0
Ottawa	6.9	7.2
Toronto	8.9	8.1
Hamilton	12.0	10.6
Winnipeg	5.9	5.6
Edmonton	8.4	7.7
Calgary	7.0	7.8
Fort McMurray	5.4	3.4
L.A. County	25.0	22.1
New York	14.9	15.2
Dallas	13.2	12.9
Seattle	10.4	7.9

Source: Clean Air Strategic Alliance (CASA) 2010

Nonetheless, the oil sands industry remains the dominant source of virtually all emissions in the northern regions of Alberta, due to its size and the near absence of other types of industrial activities in the area. Over 1,400 unique pollutants were inventoried as being emitted in this area by the oil sands industry (TMAC 2003). The majority of the total mass emissions (98%) are made up of only fifteen compounds. The list comprises well known criteria air contaminants like sulphur dioxide (SO_2), nitrogen dioxide (NO_2), and fine particulate matter ($PM_{2.5}$) (see Section 7). Ozone (O_3), a criteria pollutant, which is not an emission, rather it is a consequence of atmospheric reactions involving other contaminants that are emitted, is also included. As seen earlier, most of these contaminants rarely exceed set criteria and over the last ten years, very little change in concentrations has been observed for these criteria contaminants (Kindzierski et al. 2010).

However, the remaining two percent of total emissions comprises a long list of trace air contaminants, and for many of these substances there is little or no readily available information about exposure concentrations and routes such as many metals (e.g., cadmium), PAHs, and VOCs. Some of these compounds are considered human carcinogens (e.g., arsenic, benzene, benzo[a]pyrene).

In 2005, a review was released by the Trace Metals and Air Contaminants Working Group (TMAC) of CEMA of the Regional Municipality of Wood Buffalo on current approaches and data used to assess health risks associated with air emissions in the oil sands region. Two human exposure studies and 13 environmental impact assessments (EIAs), including health risk assessments, were reviewed and discussed in this report (TMAC 2005). The two human exposure studies reviewed demonstrate only low personal exposure to trace air contaminants attributable to oil sands activities. Eleven EIAs reported that trace air contaminants associated with a project's activities indicated potential health risks. Only two EIAs suggested no health risks. However, all EIAs still concluded that projects activities would not result in significant adverse health effects. The review suggests that the use of professional judgment in the final assessment of risk is deemed "*subjective and lacks a clear mechanism to demonstrate the absence of health risk*"(TMAC 2005). Of course, there is no scientific method which can demonstrate the absence of health risks; this does not preclude making informed judgements based on rational inferences and scientifically justified interpretations of evidence to develop estimates about how low health risks may be.

The objectives of the Human Exposure Monitoring Program (HEMP) of the Wood Buffalo Environmental Association (WBEA) studies are to test whether proximity of different communities to oil sand operations has an observable effect on levels of personal exposure to selected air contaminants. In their last study, in 2006, there were 35 participants from Fort McKay and 24 from Anzac who wore personal air monitors for 24 hours/day for 7 consecutive days. Participants also had air monitoring stations set up inside and outside their homes and answered questions about their health, diet and other lifestyle factors. Contaminants sampled included $PM_{2.5}$, NO_2, O_3, and SO_2. The results show that personal exposures were observed to be below current Alberta air quality objectives (HEMP 2007, 2008). In their 2005 study, two communities were sampled: 29 participants in Fort McMurray and 30 from Fort Chipewyan. The same methodology was used and similar results were obtained (HEMP 2007). Although personal sampling methods are not available for all potential air contaminants arising from oil sands emissions, studying a set of contaminants which are known to be emitted in

large quantity by oil sands industries to provide evidence of relative exposures indoors and outdoors as well as to compare with other communities in Alberta does provide a basis to judge the likelihood that oil sands air contaminant emissions pose a serious risk to residents of the oil sands region.

Timoney and Lee (2009) reviewed and analyzed evidence collected from several cited sources to conclude that the exploitation of oil sands has major impacts on air quality. The authors base their assessment on data analysis of atmospheric emissions. The authors argue that "*present levels of some contaminants pose an ecosystem or human health risks.*" However, in this article, no assessment of human exposure was attempted to justify such a conclusion.

Guidotti (2009) suggests that the history of air quality study in the province is mixed. He argues that Alberta has never developed a high-standard infrastructure of research and air quality studies found in other jurisdictions and argues that given the economic dependence of Alberta on its oil and gas resources, it would follow that the province would have been more aggressive in tackling air issues. According to the author, acute exposure has been handled much more effectively than chronic exposure. Although he qualifies the human exposure monitoring program as generally good, he argues that the studies do not attempt to correlate levels of exposure with health outcomes: "*Their design is based on the principle that if exposure levels are not excessive, health effects are unlikely. These studies have therefore been opened to criticism because they are not completely responsive to community concerns and because they do not address the central question of health outcomes associated with actual exposures*" (Guidotti 2009). While he implies that meaningful health outcome studies are possible he does not explain how such health studies could be done effectively with clear results in the small local populations where the lack of exposure to contaminants at levels expected to cause health effects suggests any health effects measured would be subtle at best.

10.4.1.3 Local Food Exposure

At the request of Alberta Health and Wellness, the lifetime cancer risks to Aboriginal people living in the Wood Buffalo region from exposure to inorganic arsenic were examined (AHW 2007a). The analysis by Cantox Environmental Inc. (CEI) was prompted, in part, by the earlier findings of a human health risk assessment (HHRA) completed by Golder Associates (2006) for a proposed oil sands development (the Suncor Voyageur project), which suggested local Aboriginal people may be exposed to an incremental lifetime cancer risk (ILCR) attributable to arsenic exposure of approximately 450 extra cases of cancer for an exposed population of 100,000 people. Notably, this original upper bound cancer risk estimate was not adequately clear about what proportion of the cancer risk was attributed to a baseline (background) exposure case rather than that of any contribution of the oilsands project under study. However, the CEI HHRA concluded that almost the entire cancer risk estimate was based on baseline (background) exposure. The original exposure analysis also used older monitoring data which included a number of results that were non-detectable by the analytical method used and the values used in the HHRA were assumed to be 50% of the detection limit to be cautious, a common practice for such data. The problem with these older data is that the detection limits were relatively high, so the assumed values used in exposure calculations were also high compared with more recent exposure data collected by Alberta Health and Wellness using much better detection limits (0.001 µg/g vs. 0.5 µg/g).

CEI used the more recent data for game meat concentration as well as a number of better justified assumptions to generate their ICLR estimates.

According to the CEI analysis, indigenous people living in the Wood Buffalo region had exposures to inorganic arsenic, notably by the consumption of drinking water and the consumption of sport fish, which contributed up to 27% and up to 31% of the total combined predicted exposure, respectively. For perspective, the drinking water exposure estimate was derived using an upper 95% confidence limit estimate for arsenic levels in the Athabasca and Ells Rivers (based on 57 samples combined) of 1.2 µg/L. That upper bound level which is intentionally cautious is eight-fold below the maximum acceptable concentration (MAC) for lifetime consumption of arsenic according to the Guidelines for Canadian Drinking Water Quality (Health Canada 2010) and it is within the range of cancer risk estimates considered to be negligible by Health Canada. Lesser, but still significant, contributions were revealed for the consumption of roots and other below-ground plants and the consumption of game meat (using measured values with a realistic detection limit). The CEI HHRA provided some perspective on the levels of arsenic in moose meat and in cattail vegetation by comparing them with data for the Edmonton region and for the Yukon which for regions unaffected by oil sands development showed similar values to samples collected from the oil sands region. The estimated arsenic contribution to Indigenous populations from the remaining exposure pathways was negligible.

Based on the CEI reassessment of arsenic cancer risk, the most cautious estimate was a combined future cancer risk of 35 cases per 100,000 exposed, of which all future oil sands developments contributed less than 2 cases per 100,000 exposed (occurring over an 80-year lifetime). When these estimates were applied to the population of slightly over 8,000, the maximum number of cancer cases over an 80-year lifetime exposure period that might be caused by arsenic was fewer than 3 for combined exposure (baseline plus future oil sands developments) and fewer than 0.2 additional cases for the future oil sands development estimates. The meaning of these estimates, which are always confusing at best, is that arsenic exposure cannot be expected to contribute to any observable change in cancer occurrence among the local population. Consequently, arsenic, despite being acknowledged as a human carcinogen, is very unlikely to contribute to cancer risk in Fort Chipewyan.

Mercury contamination in fish is another risk, because when the wetlands which originally covered the oil sands are drained, high concentrations of mercury can be released into the surrounding water bodies. According to Timoney and Lee (2009), elevated levels of mercury and arsenic in the local fishes are a concern. However, the authors do not provide any comparison of mercury levels in fish with other regions of Alberta or elsewhere. Nor did Timoney and Lee conduct any risk assessment for either arsenic or mercury to reach any conclusions about health risks attributable to the consumption of fish.

There are data on mercury in fish from the oil sands region from the RAMP data base and these are compared with mercury data for other regions of Alberta in Table 10.7 and with literature data for elsewhere in Table 10.8. The comparative data show no evidence that mercury levels in fish of the oil sands region are unusual or elevated compared with many other locations unaffected by oil sands or other industrial discharges.

Table 10.7 Total mercury concentrations in fish muscles reported in Alberta waters

Location and Species		**Year**	**Mean (µg/g wet weight)**	**Maximum or (90th % ile)**	**Number of samples**
Oil Sands Region					
Athabasca River	Walleye	1998	0.28	0.37	23
		2001	0.41	0.46	10
		2002	0.36	**0.84**	25
		2003	0.39	**0.72**	25
		2005	0.47	**0.71**	29
	Lake Whitefish	1998	0.09	0.09	7
		2001	0.11	0.11	10
		2002	0.13	0.45	25
		2003	0.10	0.18	18
		2005	0.09	0.17	26
Clearwater River	Walleye	2004	0.30		2
	Northern Pike	2004	0.23	**0.82**	16
		2006	0.18	0.40	26
		2007	0.15	**0.62**	31
Muskeg River	Northern Pike	2001	0.13	0.14	10
		2002	0.11	0.21	6
		2004	0.22	0.25	5
Christina Lake	Walleye	2003	0.42	**0.77**	20
	Lake Whitefish	2003	0.09	0.16	23
	Northern Pike	2003	0.42	**0.66**	13
Central Alberta					
Lac la Nonne	Walleye	2008	**0.63**	**1.17**	19
	Northern Pike	2008	**0.56**	**0.73**	7
Lac Ste Anne	Walleye	2008	0.13	0.17	20
	Northern Pike	2008	0.14		2
Southern Alberta					
Oldman River	Northern Pike	2006	0.18	(0.27)	15
Red Deer River	Walleye	2006	**0.79**	**(1.07)**	7
	Mountain Whitefish	2006	**0.12**	**(0.17)**	8
	Northern Pike	2006	0.27	(0.43)	7
S. Saskatchewan River	Walleye	2006	**0.62**	**(1.07)**	14
	Lake Whitefish	2006	0.13	(0.17)	10
	Northern Pike	2006	0.35	**(0.57)**	12
Pine Lake	Walleye	2006	0.41	**(0.73)**	11
	Northern Pike	2006	0.27	(0.34)	11

Numbers in **bold** are above the 0.5 µg/g criterion for mercury in commercial fish

Source: extracted from AHW 2009a, b, c

Table 10.8 Mean total mercury concentrations in fish muscle reported in the literature

Species	**Mean (µg/g, ww)**	**Location**	**Reference**
Walleye	0.05 – 0.99	18 Lakes, Northern Glaciated Plains, U.S.	Selch et al. 2007
	0.19 – 0.30	Reservoirs, Manitoba, Canada	Bodaly et al. 2007
	0.42 – 2.98	Wabigoon River system*, Ontario, Canada	Kinghorn et al. 2007
	0.98 – 1.00	19 undisturbed lakes, Haute Mauricie, Quebec, Canada	Garcia and Carignan 2005
	1.29 – 3.73	18 disturbed lakes, Haute Mauricie, Quebec, Canada	Garcia and Carignan 2005
	0.759	lakes, rivers and reservoirs in northeastern of U.S. and Canada (N=19,178)	Kamman et al. 2005
	0.58	Great Lakes, U.S.	Gerstenberger and Dellinger 2002
	0.47	Lakes in Northern Canada	Lockhart et al. 2005
	0.05 – 1.34	Canadian Arctic, Canada	Braune et al. 1999
	0.32 – 1.26	29 Lakes in the La Grande complex watershed, Quebec, Canada	Verdon et al. 1991
	0.19 – 1.43	Mackenzie River Basin Lakes	Evans et al. 2005 a
Northern Pike	0.26 – 0.32	Reservoirs, Manitoba, Canada	Bodaly et al. 2007
	0.44 – 2.10	Wabigoon River, Ontario, Canada	Kinghorn et al. 2007
	1.00 – 2.55	19 undisturbed lakes, Haute Mauricie, Quebec, Canada	Garcia and Carignan 2005
	1.90 – 6.44	18 disturbed lakes, Haute Mauricie, Quebec, Canada	Garcia and Carignan 2005
	0.645	lakes, rivers and reservoirs in northeastern of U.S. and Canada (N=19,178)	Kamman et al. 2005
	0.16 – 1.1	Mackenzie River Basin, Canada	Evans et al. 2005a
	0.12 – 0.74	Mackenzie River Basin, Canada	Evans et al. 2005b
	0.378	Lakes in Northern Canada	Lockhart et al. 2005
	0.623 – 1.51	Yukon River, Kuskokwim River, US	Jewett et al. 2003
	0.11 – 0.63	Canadian Arctic, Canada	Braune et al. 1999
	0.25 – 0. 90	29 Lakes in the La Grande complex watershed, Quebec, Canada	Verdon et al. 1991
Lake Whitefish	0.06 – 0.07	Reservoirs, Manitoba, Canada	Bodaly et al. 2007
	0.08 – 0.21	Wabigoon River, Ontario, Canada	Kinghorn et al. 2007
	0.54 – 1.18	19 undisturbed lakes, Haute Mauricie, Quebec, Canada	Garcia and Carignan 2005
	0.51 – 1.18	18 disturbed lakes, Haute Mauricie, Quebec, Canada	Garcia and Carignan 2005
	0.209	lakes, rivers and reservoirs in northeastern of U.S. and Canada (N=19,178)	Kamman et al. 2005
	0.01	Great Lakes, U.S.	Gerstenberger and Dellinger 2002
	0.04 – 0.35	Mackenzie River Basin, Canada	Evans et al. 2005b
	0.11 – 0.13	Lakes in Northern Canada	Lockhart et al. 2005
	0.02 – 0.82	Canadian Arctic, Canada	Braune et al. 1999
	0.07 – 0.30	29 Lakes in the La Grande complex watershed, Quebec, Canada	Verdon et al. 1991

* The highest reported levels reflect current recovery levels in the highly contaminated Clay Lake system that received over 10 tonnes of mercury discharge from a chlor-alkalai plant from 1962 to 1970.

Source: (from AHW 2009a)

10.4.1.4 Odours

As noted in the discussions of air quality (Section 7.3), there have been increasing incidents in the immediate vicinity of the original Suncor and Syncrude developments of levels of H_2S and TRS that exceed air quality guidelines based on odour detection. The air monitoring station in the nearby community of Fort McKay has not detected these occurrences of guidelines being exceeded, but odour is certainly recognized as a problem for this community. Although odour has often been considered a nuisance rather than a health effect, chronic odour problems become a burden on community well-being which ultimately leads to stress with the possibility of associated health effects. Resolution of the odour problems being caused by oil sands developments is clearly necessary.

10.4.1.5 Concerns Over Health Risk for Environmental Contaminants

Timoney (2007) reviewed environmental monitoring data and relevant publications to provide a report on public health risks for Fort Chipewyan. The main concerns identified related to mercury, arsenic and PAHs. These observations need to be considered against the concerns which had been raised earlier and resulting controversy about the occurrence of excess cancer in Fort Chipewyan (CPSA 2009).

Arsenic. Potential cancer risk from exposure to arsenic in the oil sands region was raised in Section 10.2.1.3 (Local Food Exposure) which noted different cancer risk estimates between an initial risk assessment prepared for Suncor (Golder Associates 2006) and a subsequent re-assessment by Cantox Environmental (AHW 2007a) which used more recent data and avoided using game meat exposures based on assuming non-detect samples contained half of a high detection limit thereby artificially over-estimating this exposure route. Both risk assessments relied heavily on assumptions, a reality for most initial health risk assessments which are typically done without substantial targeted local exposure data. Likewise, both assessments attributed most of the arsenic cancer risk to background arsenic exposure rather than additional exposure arising from oil sands developments. Although the risk predictions indicate that the number of theoretical cancer cases that might conceivably be attributed to arsenic exposure would be too small to detect in a population of 8000 potentially exposed in the region, these predictions are criticized by Timoney (2007) because they rely so heavily on assumptions, some of which Timoney challenges. The basic arsenic exposure evidence required to develop a more robust and defensible cancer risk assessment can be obtained with a focused and purpose-designed exposure study (e.g., measurement of arsenic speciation in commonly consumed fish, wildlife and vegetation along with surveys of consumption patterns). Given the long history of concerns about cancer risk in the region being increased by oil sands development, obtaining the required exposure evidence and performing an updated cancer risk assessment should be a priority. The evidence available to date does not support arsenic exposure being an explanation for any excess cancer in the region.

Polycyclic Aromatic Hydrocarbons (PAHs) or Compounds (PACs). As noted in Section 10.3.1.2, PAC is a broader term which includes all the strictly hydrocarbon PAHs as well as heterocyclic PAHs—i.e., those containing sulphur, polycyclic aromatic sulphur heterocycles (PASH) or polycyclic aromatic nitrogen heterocycles (PANH), nitro-PAHs, and oxygenated PAHs. The pure hydrocarbon PAHs have

received the most attention in toxicology studies over many decades while the other compounds much less attention. The reason for this difference is that PAHs are much more widespread as pollutants, particularly as products of incomplete combustion, whereas the heterocyclic compounds must generally be found in the parent source material, such as petroleum or bitumen. The heterocycles are not products of industrial processing as such although creating opportunities for greater leaching of natural bitumen deposits might lead to higher dissolution of heterocycles into flowing waters.

For the purposes of this discussion, only the PAHs and sulphur heterocycles will be considered in relation to human health risk because the latter are the major group of compounds reported in recent monitoring research directed at PAC emissions from oil sands operations (Kelly et al. 2009). Because some of these compounds are recognized as carcinogens, Timoney (2007) and Timoney and Lee (2009) raise them as plausible contaminants to explain excess cancer rates among residents of Fort Chipewyan. Kelly et al. (2009) found that the PACs they were monitoring were only elevated within 50 km of oil sands operations and dissolved PACs in the Athabasca River were not elevated by the time it reached the delta to Lake Athabasca. Timoney (2007) expressed concerns about PAH levels in sediment sampling at Athabasca delta sites reported by the Regional Aquatics Monitoring Program in 2000 (Golder Associates 2001) as indicating a trend towards increasing values compared with historical data (1976–1999). The most recent (2009) summary of RAMP data going back to 1997 does not show any consistent evidence of increasing PAH levels in Athabasca River Delta sediment samples over the 12 years of that program; Section 8.4 (RAMP 2010).

The cancer risk assessment of PAHs found in the environment is complicated and difficult because each sample is invariably a mixture of many different compounds, only some of which are known to cause cancer in experimental animals. In the case of recent studies making a case for PAH contamination from oil sands operations, Kelly et al. (2009) reported that less than 25% of PACs found in their sampling were four-ring or higher while 28–42% of PACs were dibenzothiophene homologues. Among the PAHs accepted as animal carcinogens, all have four or more rings, while the sulphur heterocycles such as dibenzothiophene and its alkylated homologues are not considered carcinogenic (Warshawsky 1992). Even among those PAHs considered carcinogenic, the potency (how little is required to initiate a tumor) varies over at least a thousand-fold from weakest to strongest making generalizations about the carcinogenicity of mixtures of PAHs misleading without taking relative potency into account (Bowstrom et al. 2002; Collins et al. 1998; Law et al. 2002).

In theory, human exposures to PAH could arise from air inhalation, drinking water ingestion, food ingestion, and dermal contact (ICPS 1998). In practice, unless individuals are smokers, a characteristic which will dominate PAH exposure, food ingestion has been most commonly found to dominate PAH exposure over the other exposure routes (Chuang et al. 1999; Cirillo et al. 2006; Fiala et al. 2001; Lee and Shim 2007; Scherer et al. 2000; Vyskocil et al. 2000; Waldman et al. 1991; Wilson et al. 2003; Wilson et al. 2000). Fish would likely be the main food source worth investigating as the major potential PAH exposure via food. However, PAHs are generally metabolized rapidly so that while they will certainly bioconcentrate from water because of their lipophilicity, they do not bioaccumulate in a food web to the degree of more persistent pollutants (Baussant et al. 2001; Jonsson et al. 2004; van der Oost et al. 2003).

Although the evidence available for water and sediment levels of PAHs downstream of oil sands operations does not support an expectation that PAHs pose a substantial cancer risk to downstream consumers, the local concerns over cancer risk and the frequent references to PAHs as carcinogens suggest that a rigorous risk assessment should be done. To avoid the trap of many human health risk assessments which rely far too heavily on assumptions to establish key exposure information, such an evaluation should be based on a thorough assessment of human exposure to PAHs by data collection on exposure media in the region.

Mercury. This contaminant is inevitably mentioned in discussions of human health risk from the environment because there have been notorious examples of human poisoning by environmental exposure. Because of that history, there has been a lot of attention, worldwide, in setting exposure criteria for mercury in human food. In particular, fish are recognized as a potentially serious source of mercury ingestion (Health Canada 2007). Fortunately, the risk assessment for mercury is much more certain than for most other contaminants because the criteria levels for fish consumption are well established and generally recognized around the world, so monitoring of fish to determine mercury levels against those criteria levels is a viable and meaningful option.

Alberta has maintained a long-term program to monitor fish for mercury and this program has been substantially expanded in the oil sands region by RAMP. Relevant data were summarized in Table 10.7 (Section 10.3.1.3) and show that while some fish in the oil sands region, particularly walleye, exceed the Health Canada consumption guideline of 0.5 µg/g and many exceed the subsistence consumer guideline of 0.2 µg/g, these occurrences are not unique to the oil sands region. In fact, mercury levels appear to be higher in central and southern Alberta, well out of the range of influence of oil sands emissions. The most recent data (RAMP 2010) for 2009 show that mean mercury levels for lake whitefish are consistently below the subsistence consumer guideline, at sites in the oil sands region, mercury levels for northern pike and walleye were either below the general consumer or the subsistence consumer guideline. The one exception was walleye in Lake Athabasca in 1977. The occurrence of some northern pike and walleye exceeding mercury consumption guidelines is a concern for this region, but the distribution of mercury contamination of fish in Alberta provides no evidence to suggest that this contamination is caused by the oil sands industry. Likewise, comparison of these data with mercury contamination of fish across northern Canada suggests a generalized source of mercury affecting fish.

10.4.1.6 Effects of Contaminants on Physical Health in Vulnerable Groups

This section focuses on specific chronic effects observed in a vulnerable group due to their specific exposure and sensitivity. The most sensitive group identified is the Aboriginal population living in the oil sands area.

An often cited example is the small northern Alberta Aboriginal community of Fort Chipewyan. In this community of 1,200 people, living downstream from the oil sands projects, six cases of rare cancers of the bile duct, also called cholangiocarcinoma, had been diagnosed by a local physician in 2006 (Tenenbaum 2009). The physician's claims were controversial and led to an investigation by the College of Physicians and Surgeons of Alberta which found that this physician "*made a number of*

inaccurate and untruthful claims" (CPSA 2009).[21] The CPSA determined it was not in the public interest to penalize the physician beyond censuring his actions. The physician's claims also became the subject of numerous media accounts and even an Academy Award-nominated documentary, *Downstream*, (Leslie Iwerks 2010) with the synopsis: "*At the heart of the multi-billion dollar oil sands industry in Alberta, Canada, a doctor's career is jeopardized as he fights for the lives of the aboriginal people living and dying of rare cancers downstream from one of the most polluting oil operations in the world*."

After an initial review of cancer rates which showed no reason for concern, the Alberta Cancer Board conducted a cancer cluster study following guidance from the U.S. Centers for Disease Control (Chen 2009). Of the six suspected cases reported by the community physician at the time, only two were confirmed cases of the relatively rare cancer cholangiocarcinoma; three of the reported cases were found to be other cancers while the other one was not cancer. Specifically, this study, concluded at a 5% significance level, that:

• *The two cholangiocarcinomas in Fort Chipewyan were within the expected range.*

• *The cancer rate overall (51 cancers in 47 individuals) was higher than expected (39).*

• *Higher than expected numbers of cancers of the blood and lymphatic system, biliary tract cancers as a group, and soft tissue cancers were found.*

• *These findings were based on a small number of cases and could be due to chance, increased detection or increased risk in the community*.

This study was reviewed by independent international experts who pointed out that the increase in cancer incidence is not evidence that an environmental exposure is a cause but it remains a possible explanation through past occupational exposure including that for residents who worked at the uranium mines in Saskatchewan (Armstrong et al. 2009).

A 2006 analysis of the health status of Fort Chipewyan residents showed that residents have elevated prevalence rates of type 2 diabetes, hypertension, renal failure, and lupus (AHW 2006). Timoney and Lee (2009) have argued that, although no study has been able to prove the cause-effect relationship between exposure and specific health effects in the case of Fort Chipewyan, the exposure to environmental contaminants such as arsenic and mercury, in particular in local food, is a plausible

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[21] "*A summary of the findings of the College of Physicians & Surgeons of Alberta is that:*

o Dr. O'Connor failed to inform public health officials and the Alberta Cancer Board of the identities of and clinical circumstances of patients whom he'd diagnosed with various types of cancer in a timely manner.
o Dr. O'Connor did not respond to multiple requests for information after he had made public his concerns about the incidence of cancer in the community of Fort Chipewyan.
o Dr. O'Connor made a number of inaccurate or untruthful claims with respect to the number of patients with confirmed cancers and the ages of patients dying from cancer.

The College of Physicians & Surgeons of Alberta wishes to emphasize that Dr. O'Connor's advocacy for the people of Fort Chipewyan, in bringing forward his concerns about a possible increase in the incidence of cancer and other health conditions, has never been and is not a matter of concern for either the complainants or the College of Physicians and Surgeons (CPSA), and is not and has never been an element of the complaint. To the contrary, any physician's advocacy in raising potential public health concerns is to be lauded." (emphasis added)

factor. They point to the important levels of these contaminants detected in local fish, consumed in particular by the Aboriginal population of Fort Chipewyan. It is important to note that this region has also had other important mining activities (uranium) apart from oil sands industries. Residents from the community have raised concerns that their health has been adversely affected by contaminants that have possibly originated from the upstream oil sands or uranium mining.

The concerns by community members about their health are understandable particularly with the number of claims being made about toxic pollution from oil sands emissions. Evidence to document environmental contaminant exposures sufficient to pose measureable health effects in these communities has yet to be reported. However, community members may understandably believe that not enough effort has been devoted to trying to find potential contaminant exposures, so the recent media reports that the Alberta Minister of Health and Wellness plans to undertake a major health study with local Aboriginal groups is certainly welcome. Hopefully, this study will not raise unachievable expectations for what such studies are capable of showing in a small population because very clear black and white answers are unlikely to be found.

10.4.2 Impacts on Community Health

10.4.2.1 Boom-Town Effect

In this section, challenges to meet increasing service demands caused by high population growth in Fort McMurray, and the health impacts that result, are examined.

Fort McMurray has experienced a booming economy which can have positive side effects such as jobs, business opportunities, and increased wealth for many in the community. A commonly used benchmark in the social scientific community for defining boom town conditions is at least 6% in population growth for each of three or more consecutive years. The population of Fort McMurray has been increasing at an average rate of 8.7% per year from 2001 to 2006 (Archibald 2006).

Earley (2003) explains that "*Along with this dramatic increase in population have come many of the effects associated with boom-town style development including inflation, extreme housing shortages, labour shortages in all sectors, family stress, drug and alcohol abuse, increased crime.*"

Sustainable community indicators such as housing costs, job turnover, alcohol and drugs, and health were found to be raising concerns among the majority of interviewed residents of Fort McMurray (Archibald 2006).

Earley (2003) points out that municipal debt is an important socio-economic impact felt in Fort McMurray: "*While the municipality goes into debt to build infrastructure for the future, it may be forced to cut social programs unless alternative sources of funding are made available by the province or industry*." According to Alberta Finance and Enterprise, "*inadequate infrastructure and public services in the Fort McMurray area could reduce the quality of life for residents and hurt the region's ability to attract and retain workers*" (AFE 2009).

According to Alberta Economic Development, as cited by Earley (2003), a deficit of $410 million in infrastructure spending for the Fort McMurray region was predicted between 2003 and 2007. A more

detailed analysis of infrastructure needs was performed in the so-called Radke report (Gov AB 2006), released at the end of 2006, which clearly recognized the scope of the problems that had developed. Among many wide-ranging, cross-government recommendations, it called for:

> *A significant infusion of resources, both operating and capital, is required to avoid further deterioration and possible collapse of the system as growth continues in the area. A number of steps should be taken now to improve health care delivery in the short term, pending completion of a longer term vision and plan:*
>
> - *Development and funding (capital and operating) of a continuing care and supportive living facility located outside the hospital which will free up space in the existing hospital for active care treatment.*
> - *Creation and funding of adequate isolation rooms to deal with possible pandemics.*
> - *Priority attention needs to be directed to the attraction and retention of health care workers in the Northern Lights Health Region. The provincial government should design and fund temporary salary and wage market modifiers for a three- to five-year trial period that would provide additional compensation to physicians, nurses and other specialized health care workers who are willing to locate in Fort McMurray.*
> - *Immediate funding outside the current funding formula should be established to bring the standard of health care service in Northern Lights Health Region to acceptable levels. The requirement for a recovery (deficit elimination) plan to address the current deficit should be suspended until acceptable service levels are reached.*
> - *Alberta Health and Wellness and Northern Lights Health Region need to engage in a process to reconcile health care registration numbers with municipal census data on an annual basis and adjust base funding for the region accordingly.*
> - *Area structure plans should reserve land for future medical sites in accordance with the agreed upon vision.*
> - *Immediate funding should be allocated to build a parkade at the current hospital site. Access for helicopter cases (medivac) would be improved by a heli-pad on top of the parkade.*
> - *Given the high turnover of senior staff and the complex process for obtaining capital approvals, ways should be found to expedite relatively simple capital requests, such as the parkade and the interim ambulatory care re-development program.*

In January 2008, the Government of Alberta announced that it was "*allocating more than $420 million to projects in Fort McMurray to alleviate the pressures of rapid growth and enhance the quality of life of local residents*." Although $300 million of the funds was directed towards construction of two major highway interchanges, the remaining funds to be allocated over three years were earmarked for:

"*expanding long-term, emergency and outpatient care; support for policing; contributions to a new child care centre; school buildings; and other essential community infrastructure.*"

Ironically, facing a tighter budget only 18 months later, the Government of Alberta announced a deferral of four years in construction of an approved elderly long-term care facility. This facility would have eased pressures on the over-stretched acute care facilities in Fort McMurray. The MLA for Wood Buffalo (a former Minister of Environment) who spoke out against this decision was kicked out of the Government caucus in July 2009. This facility has now been funded again with a call for expressions of interest by potential contractors having been made in June 2010.

A Social and Infrastructure Assessment Modeling (SIAM) tool is under development to assist the Government of Alberta in further assessing the need and costs associated with infrastructure and essential services arising from new industry development within the oil sands regions, as well as help with establishing priorities. The Government of Alberta is examining and working with municipalities to identify opportunities to regionalize municipal service delivery and financing to facilitate effective allocation of resources in high-growth areas (Gov AB 2009).

10.4.2.2 Effects on Health Care Services

In this section, the impacts of oil sands development on the capacity of the region to provide adequate health care services to the population are discussed.

In a letter to the Canadian Medical Association Journal, Dr. Michel Sauvé, Fort Medical Association President in Fort McMurray, states that between 30% and 40% of the population still did not have a family doctor (Sauvé 2007). Every year, nearly half of the region's hospital and public health staff left, because they either could not afford housing or could not stand the chaos. A record of 156 patients were seen during a 12-hour shift by an emergency doctor. Sauvé reports that after eight years of oil sands development, Northern Lights Health Region had fewer hospital beds than a third of its provincial counterparts (Sauvé 2007).

In 2006, the Oil Sands Ministerial Strategy Committee released a report addressing social, environmental, and economic impacts of oil sands developments. To assess health care needs, the group reviewed 17 indicators which revealed that services delivered in Fort McMurray were lower than average on most indicators (emergency room wait time is one exception). Satisfaction level in Northern Lights is lower than the provincial average and there were many gaps in health care services: there were no community health facility and continuing care facility in the community, the number of acute care beds was lower than the provincial average, and they had significantly fewer specialists (Gov AB 2006).

The report indicates that "*in northern Alberta, most communities have faced difficulties in attracting and retaining physicians and specialists. The region had a 42 percent vacancy rate for physicians in 2006. Sixteen percent of non-physician health care positions were vacant. There were nearly 175 vacancies in the region out of a total staff complement of 996 full time equivalents; 138 of those vacancies were in Fort McMurray*"(Gov AB 2006).

Two recent EIAs, available at the time of writing this section, were reviewed (Imperial Oil Resources Ventures Limited 2005b, Deer Creek Energy Limited 2007). Both studies acknowledged the existence of community health impacts in their chapters on socio-economic effects. For example, the Kearl Mine Development EIA lists key socio-economic impacts as follows:

> *(1) increased pressures on the traditional land and culture of Aboriginal peoples*
>
> *(2) increased traffic, both within the region and between the region and Edmonton*
>
> *(3) high and escalating housing costs, which is the primary cause of the high cost of living in Fort McMurray*
>
> *(4) Rapidly growing northern resource town economy characterized by the following community stresses:*
>
> - *weak sense of community*
> - *geographic isolation*
> - *prosperity gap*
> - *prevalence of dual income couples and other employees working long hours, often on a shift basis*
> - *increased levels of alcohol and drug abuse, gambling, and crime*
> - *infrastructure deficit*
> - *service deficit*

However, it is also important to note that these studies did not evaluate the economic consequences of such negative impacts; they only stated briefly that the benefits far outweighed the costs, without presenting any evidence to support such wide-ranging conclusions. Some measures for mitigation of impacts were proposed (maintenance of industry medical services on site, future donations to community foundations, etc.), but these were apparently offered from a proponent perspective that the government is responsible for providing the services that would be impacted.

10.4.3 Technological Catastrophes (Leading to Environmental Disasters)

In two recent oil sands EIAs reviewed, the analysis on the risks of technological or environmental catastrophe is mixed. (Imperial Oil Resources Ventures Limited 2005a; Deer Creek Energy Limited 2007). Although one EIA (Deer Creek Energy Limited 2010) provided an extensive analysis of a large number of potential “accidents” (dyke failures, flooding, spills, etc.) in response to a request for more information on this topic, it was not clear that a holistic analysis of *what could go wrong* informed by past experience (process fires), predicted futures (i.e., climate change impacts such as extreme winds, forest fires, etc.) was performed, or scientific knowledge on the actual efficacy of the proposed design was available. There have been large gaps in information submitted in EIAs that have not been

required by the government nor provided by the companies, specifically dealing with consequences of technological disasters. Because there have been serious fires at both Suncor and Syncrude over their operating lives, there is certainly experience which could be drawn upon to judge the ability of current and future operations to deal with major disasters. In particular the series of equipment failures and a major fire at the Suncor upgrading plant in the winter of 1981–82, required a complete shutdown for months and led to major oil releases to the Athabasca River (see Section 3.2.2).

Another major concern for technological disaster has been the vulnerability of any of the tailings dykes failing with resultant release of tailings to the environment. A particular focus for this concern has been the original Suncor tailings pond 1 at Tar Island which is located immediately adjacent to the Athabasca River (Figure 8.2) Fortunately, this tailings pond is the first one to be subject to reclamation by removal of remaining MFT and backfilling with sand, which makes increasingly unlikely the prospects of technological disaster associated with major tailings release to the Athabasca River. A tailings dyke failure at any other tailings pond remains a concern that must continue to be addressed. Considerations on tailings dyke stability and consequences of dyke failure have been provided in the most recent EIA (Deer Creek Energy Limited 2010).

Predictions on future climate conditions are present in the last EIA of Imperial Oil, but it concentrates only on the future averages, and fails to examine all the extremes and their probability of occurrence in the future, which remains a large gap (Imperial Oil Resources Ventures Limited 2005a). Indeed, no information is provided evaluating the consequences of extreme and prolonged drought (including consequences such as important forest fires), torrential rains, or storms with violent winds. However, extreme weather is one of the most dramatic consequences of climate change and should be considered as part of EIAs, with a clear focus on cumulative effects for the region.

10.4.4 Consultation Process

In the oil sands area where many industrial developments are planned or are already underway, the community may become concerned about the possible health effects. The perception of health status and well-being in relation to environmental quality and industrial developments is rarely addressed in conventional risk assessment, since this type of issue is hard to quantify in simple terms. To address these issues, consultations were held in 2006 by the Oil Sands Consultation Advisory Group with multi-stakeholders across Alberta (OSC 2007).

In their final report, the authors point out that air and water quality concerns were heard extensively throughout the consultation process and the protection of air and water was considered important by all members. A First Nations panel member and community leader highlighted these concerns:

> *Communities in the oil sands regions are very concerned that their health and wellness are being negatively affected by oil sands activity. Current project Terms of Reference only require a company to report a company-specific health risk assessment—to date there is no comprehensive means of measuring the cumulative health effects that development has had on communities. Some suggest that communities are being negatively impacted*

> *and that cancer rates are increasing. It is important that we have long term health studies to monitor exposure to pollutants and changes in health conditions, and that the scope of work be identified in cooperation with the potentially affected communities* (OSC 2007, p. 42).

The representatives for the environmental NGOs agreed and went further by saying that long-term studies of chronic exposure to pollutants were necessary. With that statement, the Government of Alberta replied that it will respond to the health concerns raised by stakeholders by engaging in various actions such as:

> *Conduct or provide assessments necessary, including peer-reviewed processes as appropriate, to establish a baseline health status profile of Albertans living in the oil sands regions. In addition, the government plans to monitor the cumulative impact of factors that influence health on an ongoing basis, including environmental effects as reflected by exposure to contaminants influencing health, and socio-economic effects on health arising from rapid growth in the region* (OSC 2007, p. 42).

Concerning health care services, the members agreed on the importance of providing a necessary level of health and other wellness services in areas where oil sands development was resulting in shortages of service capability. Aboriginal communities voiced their concerns about the pressures on the health care system due to the growth in population in the oil sands regions. These pressures can be exacerbated due to the relative remoteness of many predominantly Aboriginal communities. According to them, the transition from traditional to modern lifestyles has contributed to the health status of northern Aboriginal people being lower than other Albertans living in comparable circumstances (OSC 2007).

A 2007 report addressed Crown consultation with Aboriginal people in oil sands development (Passelac-Ross and Potes 2007). One of its main conclusions is that Alberta is failing in its duty to consult Aboriginal people in oil sands development, noting that: "*the Alberta government and the First Nations differ at a fundamental level on the purpose of consultation: for the former it is a tool in decision-making, for the latter it is a tool for rights protection.*" Furthermore, these authors concluded that the "*current consultation processes do not meet the high standard of conduct required by the Supreme Court.*" Alberta signed a consultation accord with Alberta's Treaty-Holders in May 2008, so the foregoing critique may not apply to the current agreement in place (Gov AB 2008).

One objective of the Government of Alberta in their Annual Progress Report (*Responsible Actions: a plan for Alberta's oil sands*) in 2009 was to strengthen their approach and reconcile interest in the Aboriginal consultation process (Gov AB 2009). A number of actions were taken such as meetings with various First Nations groups to identify community concerns. Also, the Government of Alberta facilitated a meeting in Fort Chipewyan to discuss the Alberta Cancer Board's report. In addition, senior medical officials committed to continuing discussion about community health needs. Government of Alberta ministers met with a number of stakeholders in Fort Chipewyan to learn more about Aboriginal traditional knowledge and discuss a community-based monitoring program to

increase confidence, capacity, and participation in the monitoring of local water and air quality (Gov AB 2009).

The implementation plan for Responsible Actions (Gov AB 2010) lists the following recent developments: pilots for Aboriginal consultation are complete and the consultation policy is being implemented, initiative funding has been provided to all interested First Nations for the completion of comprehensive Traditional Use Studies, and substantial revisions to the *First Nations Consultation Policy on Land Management and Resource Development* are complete.

Finally, recent projects have maintained substantial consultations with affected First Nations and conducted extensive traditional use studies (Deer Creek Energy Limited 2010). An extract from an EIA update is provided in Appendix 9. An evaluation of the merit of these studies was beyond our review capacity but those with an interest and expertise in these matters should consider what has been done and identify the improvements where needed.

10.4.5 Beneficial Impacts

Oil sands projects can have beneficial impacts on individual and community health and well-being. The increase in incomes can improve the quality of life and living standards.

Oil sands projects provide jobs and stimulate the creation of new businesses which leads to improved incomes and better access to goods and services (ICMM 2010). Being employed can enhance mental health and well-being and reduce stress. This is particularly important for chronically under-employed groups, such as First Nations. Employment of First Nations members in the Oil Sands is a major factor in how First Nations communities and individuals view the benefits and risks of oil sands.

According to the RMWB Census 2006, 12 % of the respondents within the RMWB identify themselves as Aboriginal. In the Fort McMurray urban service centre, 31% of Aboriginal respondents reported that they were employed by an oil sands or gas company, 20% were taking part in other activities such as being a student, 18% were employed by the service or retail sector, while 15% were employed by a contractor providing services to the oil or gas sectors (RMWB 2006).

The Aboriginal unemployment rate across the province is higher than the overall provincial unemployment rate. The Aboriginal unemployment rate in January 2010 was 15.3%, up from 10.3% one year ago (Gov AB 2010) compared with Alberta’s overall unemployment rate of 6.6% in 2009.

The stimulus that an oil sands project can bring to a local economy can help to strengthen and deepen social ties by increasing the prosperity of the community and providing resources for people to take on a wider range of social and community activities (ICMM 2010). However, the new people who come into the area may adversely affect the cohesion of local communities.

Oil sands projects can have a positive impact on health care services by identifying existing community health problems and needs, putting additional funding into local services and infrastructure, and working jointly with local health authorities to address local needs (ICMM 2010). However, projects may also place additional pressures on local health care services (including

emergency services) because of the increase in population that they can bring, particularly if they also cause disruption and lead to new or exacerbate existing health and social problems. Most oil sands projects have their own medical facilities and services available to the project workforce. The Oil Sands Developers Group (OSDG) is an oil sands industry association that shares information and development issues. They maintain that "*health centers located at member company work sites offer emergency and diagnostic services and employ doctors, nurses and other health care professionals to serve the needs of employees and lessen the burden on the local hospital. Some companies have signed mutual aid agreements to complement and enhance existing emergency services*" (OSDG 2009).

10.4.6 Conclusions on Community Health Impacts

Even taking rural and isolated reality into account, Northern Lights Health Region performed worse than other rural Health Regions for several health indicators, so there may be additional impacts that may be attributable to oil sands development in some way. There are obvious health indicator disparities that are not acceptable in a region that is generating so much wealth for the province and the country and these disparities need to be addressed regardless of their cause. These disparities have occurred at production levels of below and around 240,000 m^3/d, while current projections to 2020 expect this production level to increase by a factor of two (Section 2.2).

Health impacts, particularly under such an increased production scenario, should be examined very thoroughly, taking into account other global and simultaneous challenges such as climate change impacts on precipitation, temperature and weather variability. This assessment should include an economic evaluation of the positive and negative impacts, including infrastructure spending; extensive catastrophic risk analysis should also be included. Given the rapid pace of development, similar urgency is needed to deal with this assessment which should be completed in the short term (i.e., within two years).

Following this review of impacts at current levels of industrial activity (for bitumen producton of ~240,000 m^3/d), we can conclude that:

- Current levels of environmental exposure to contaminants through different media are not likely to cause major health impacts for the general population;
- Because we could not find published reviews of occupational exposures or industrial hygiene assessments in the workplace, health impacts through occupational exposure remain a question mark;
- Significant contaminant exposures through technological disasters remain a clear, but largely uncharacterized possibility given the scale of the oil sands;
- Potential negative cumulative effects through food exposure for specific populations such as the First Nations have not been adequately characterized by direct field measurement and remain a valid community concern;

- There are major negative effects on community health due to several simultaneous pressures on infrastructure: health and social services, water, waste and transport, lifestyle stress, demographic structures, and immigration;
- There are possible cumulative negative effects through cultural and demographic stress for specific populations such as the First Nations;
- There is a strong and pervasive perception of potential cumulative health risks among downstream community members believing that contaminants are being released to the environment at dangerous levels by oil sands projects;
- There are commonly perceived beneficial impacts related to income and employment; and

The negative impacts of oil sands projects have apparently not been evaluated so far in monetary terms, although they are widely recognized and acknowledged by both industry and government. This deficiency is considered in greater detail in Section 11.4.1.1.

11. EXTERNALITIES, PUBLIC LIABILITIES, AND IMPACT ASSESSMENT

11.1 Environmental and Health Impacts as Negative Externalities – Who Pays

From an economics perspective, the environmental and health-related impacts of oil sands activities can be considered "*negative externalities.*"[22] For the purposes of this report, two important characteristics of externalities should be kept in mind. First, environmental and health-related impacts are negative externalities in the sense that these are costs associated with oil sands development and production activities in addition to the expenditures needed to initiate and sustain production. Second, by their very nature, these additional costs will not be fully borne by oil sands developers (and their customers). As a result, these costs will not be fully taken into consideration in their decision-making processes in the absence of external (i.e., governmental) intervention aimed at ensuring that buyers and sellers of oil sands products take the associated environmental and health-related impacts more fully into account when making investment, production, and purchase decisions.

Governments can rely on different policy approaches and instruments to bring about a greater "*internalization*" of externalities in producer and consumer decision-making. In the case of the oil sands, for example, the requirement for surface mine operators to manage their effluents and not to release them directly into the Athabasca River is an example of a "*command-and-control*" approach to reducing the environmental and health-related impacts of their activities. The possibility of oil sands operators contributing a financial levy for each tonne of GHG emitted in excess of a set amount can be thought of as using an "*economic instrument*" to make these operators bear a greater proportion of the environmental costs associated with the GHG emissions.

Whatever approach is used and whatever policy instruments are implemented, efforts by governments and regulators to internalize environmental and health-related externalities will result in additional expenditures to produce and/or consume the goods whose production and consumption give rise to these external effects. This is true in general and, for the purposes of this report, in the case of oil sands related activities in particular. Therefore, to the extent that developers make expenditures aimed at mitigating the environmental and health-related impacts of oil sands development and production activities, higher total outlays will be necessary to bring projects on stream and to operate them. However, as is the case with any type of expenditures undertaken by developers, the *incidence* of spending to reduce environmental and health-related impacts, in the sense of who ultimately bears these expenditures, is affected by characteristics of the royalty and tax system applicable to Alberta's oil sands. This arises because provisions of this system are such that eligible expenditures reduce some royalty and tax payments below what these would have been in the absence of such expenditures by developers. As a result, some of the expenditures undertaken by oil sands developers are effectively borne by the Alberta and federal treasuries since both governments collect revenues from oil sands activities. The key instruments through which this effect is manifested are the corporate income tax, bonus payments, and royalties.

The Government of Canada levies a corporate income tax (CIT) on all for-profit companies operating in Canada, including oil sands developers. The Government of Alberta also levies a CIT on for-profit

[22] For a summary description of externalities from an economics perspective, see Appendix A8.

companies operating in the province and, as agent of the resource owners, relies on additional instruments to ensure that the people of Alberta, as owners, share in the revenues generated by oil sands activities. Such instruments are bonus payments and royalties.[23]

As with all other eligible expenditures, those aimed at addressing environmental and health-related impacts of oil sands development would be deductible in the calculation of federal and provincial CIT payments. Consequently, all Canadians bear a portion of these expenditures through lower CIT collections from oil sands operations. The royalty regime in Alberta has similar consequences since the base against which some oil sands royalties are assessed is a measure of revenues net of eligible expenditures. Here, owners of the resource bear a portion of expenditures undertaken by oil sands developers to address the environmental and health-related impacts of their activities through lower royalty payments than would have been received in the absence of such spending.

Bonus payments[24] by developers would also reflect their estimation of future mitigation-related expenditures. All else held equal, bonus payments would be lower in the presence of anticipated spending on actions to address environmental and health-related impacts of future oil sands development and production activities. These lower bonus payments again imply that a portion of such expenditures made by developers would effectively be borne by the resource owners the people of Alberta.

Efforts by oil sands developers to address the environmental and health-related impacts of their activities will clearly act to increase the total expenditures required for development and production. Whatever level of spending is undertaken by developers, they will not ultimately pay for all of it: the oil sands royalty and tax system ensures that all Canadians and especially Albertans – as resource owners – pay a portion of such mitigation-related spending through induced lower CIT collections, royalties, and bonus payments.

11.2 Unpriced Inputs: The Case of Water

A characteristic of oil sands production processes is that one of their key inputs – water – is made available to producers at a zero price. This is not indicative, however, of preferential treatment extended by the Government of Alberta to this industrial sector. [25] Rather, use of both surface water and groundwater in Alberta occurs within a system of licences and allocations, which are granted based on the principle of "*first in time, first in right*" (AENV 2010). The associated volumes of fresh water are then made freely available to the sectors to which they have been allocated. In addition,

[23] Descriptions of the royalty and tax system applicable to Alberta's oil sands and analyses of its properties can be found in Plourde (2009, 2010).

[24] These one-time payments by developers result from auctions used to allocate exploration rights, which can be converted into production rights if discoveries are made (Plourde 2009).

[25] The economically inefficient practice of providing water at a price of essentially zero is also found elsewhere in Canada. According to Renzetti (2007), six of 13 provinces and territories do not levy any fees for raw water withdrawal while, in contrast, British Columbia earned nearly $400 million from water withdrawal fees in 2004. More recently, the Government of Quebec has proposed new legislation, potentially for 2011, to collect fees for industrial water usage. The fees would apply to all industries extracting more than 75 m^3/day of water directly from the raw water source or from a municipal distribution system. The proposed fee is $0.07/$m^3$ and it would be applied to a list of specified industrial usages, including oil and gas extraction.

withdrawals of saline (or brackish) water from underground reservoirs are not subject to licencing provisions and, as is the case with fresh water, are freely available to users. As noted in Sections 5 and 8, additional provisions also regulate water use (and recycling) by the oil sands industry. Nonetheless, the fact remains that a key input is provided to this industry (and to other water licence holders in the province) at a price of zero. All else held equal, this would suggest that both incentives for water conservation in the oil sands industry in the short term and pressures for technological developments favouring reduced water usage in the longer term will be less effective under current arrangements than if water were priced at levels closer to its opportunity cost.

Water is essential to bitumen extraction processes currently in use. Indeed, the National Energy Board puts it this way: "*[p]rocess water is the lifeblood of an oil sands operation…*" (NEB 2004, p. 65)This situation is unlikely to change for quite some time. According to the Alberta Chamber of Resources, water-based bitumen extraction processes are expected to continue to dominate until at least 2030 (ACR 2004, p. 19). The demand for water by this industry and water allocations are discussed in Sections 4 and 8.

Total net fresh water usage per unit of bitumen and SCO production has been falling over time, in part because proportionately more water recycling and re-use has occurred and because it has proven possible to use saline/brackish water for in situ processes. ACR (2004, pp. 30–34) nonetheless considers water use to be one of the key challenges that both surface mine and in situ operators will have to address in the future as bitumen and SCO production levels grow.

11.3 Reclamation: Incentives and Liabilities

As outlined in Section 9, oil sands extraction gives rise to land disturbance issues. As far as in situ techniques are concerned, the key dimensions centre on the impacts on the boreal forest. The extent and severity of reclamation issues are perhaps most obvious with surface mining operations, where forest clearing, site dewatering (including removal of wetlands), reclamation material salvage, and overburden removal precede open-pit extraction and associated tailings accumulations. The Government of Alberta (Gov AB 2009b) indicates that 602 km^2 of land has thus far been disturbed as a result of oil sands surface mining operations (Section 9.3.1).

Reclamation of disturbed lands is thus an important component of addressing the environmental footprint of oil sands development. Alberta legislation and regulations clearly establish that the responsibility rests with developers for financing and ensuring that the required reclamation activities are undertaken. However, an inability or a failure of the developer to perform these tasks, would raise the possibility that reclamation liabilities will be borne by the public. The following discussion provides an overview of Alberta legislation, regulations, and practices to highlight the potential for public liabilities to emerge from reclamation requirements on developers.

11.3.1 Regulatory Requirements

Section 9.2.1 describes the current EPEA requirements for reclamation in Alberta. EPEA makes it clear that the duty to reclaim rests with operators (section 137). However, there are no generic guidelines to establish what level of reclamation would meet the "*equivalent land capability*" standard.

Instead, regulatory approvals for individual oil sands projects typically include more explicit conditions on the extent of reclamation activities expected. In the case of Imperial Oil's Kearl surface mine project, for example, reclamation requirements are identified in Part 6 of the approval document, run through 95 numbered paragraphs (AENV 2007, pp. 45–66) and include, among other things, the submission of an annual report on reclamation progress (paragraphs 93 to 95).

Operators are encouraged to undertake reclamation activities as extraction proceeds. However, the nature of oil sands production activities and, in particular, the long productive life of individual projects together mean that reclamation is unavoidably a long-term process and one that is especially focused on activities that occur only once production has stopped. It is within this kind of framework that the industry approaches reclamation activities, as noted by the Alberta Chamber of Resources: "*[t]he long-term objective is to return lands to as close to their natural habitat as possible in the 10 to 50 year timeframe*" (ACR 2004, p. 35). The Government of Alberta (Gov AB 2009b) suggests that operators of oil sands surface mines have reclaimed some 67 km^2 for which certificate s of reclamation have yet to be issued. As noted in Section 9, the first reclamation certificate in the industry's 43 year history was issued in March 2008 and covered an area of 104 ha (approximately 1 km^2).

Once activities associated with a given project, or part of a project, are terminated and AENV deems that the reclamation objective has been met (in other words, that the conditions related to reclamation activities outlined in the regulatory approval for the project in question have been satisfied), a reclamation certificate is issued by the province.[26] Once this certificate is issued, responsibility for any future reclamation-related problems for *mined areas* is transferred from the operator to the province (AR 115/93, section 15). Because the full extent of the related environmental degradation will most likely become evident only once responsibility has been transferred back to the province, this creates the possibility that some reclamation costs will inevitably ultimately be borne by the public. Responsibility for future reclamation problems on *plant sites* remain with operators for 25 years after the issuance of a certificate. Responsibility for any *contamination* on mine sites or plants remains with operators for life. However, since only one reclamation certificate has been issued for oil sands operations to date, much about the process, its longer-term implications, and plans to monitor and manage any continued environmental degradation over time horizons of decades and longer remains unclear.

11.3.2 Potential Problems

Given the long time horizons and the concentration of reclamation activities near or after the end of the productive life of projects, reclamation activities in the oil sands industry would appear to raise moral hazard issues. Characteristics of some economic information and incentive systems linked to the ability to hide important information about the nature of some economic agents are described below.

[26] The regulations also require operators to remediate any releases of harmful chemicals to the environment. While remediation activities are considered distinct from reclamation activities, remediation is required before a reclamation certificate is issued by the provincial government. Note as well that the inspection process that precedes the issuance of a reclamation certificate is led by officials from the province's Department of Sustainable Resource Development (SRD). Ultimately, Alberta Environment is responsible for issuing reclamation certificates for activities on *private* lands, while SRD is the issuing authority for *public* lands. Since most oil sands deposits are located on public lands, SRD is likely to be the government department responsible for issuing reclamation certificates for most oil sands developments.

Moral Hazard

> *…uncertainty that is not shared by all participants can lead to significant inefficiencies. Situations in which some people know things that others do not are said to involve asymmetric information, and these situations give rise to two problems, adverse selection and moral hazard…Moral hazard occurs whenever the consequences of a contract are affected by hidden actions or hidden information…* (Leach 2004, pp. 293–294, emphasis in original)

> *Moral hazard may be defined as actions of economic agents in maximizing their own utility to the detriment of others, in situations where they do not bear the full consequences, or equivalently, do not enjoy the full benefits or their actions due to uncertainty and incomplete information or restricted contracts which prevent the assignment of full damages (benefits) to the agent responsible.* (Kotowitz 2008, emphasis in original)

As noted earlier, given the nature of oil sands operations, reclamation activities will tend to be undertaken near or after the termination of extraction. Since operators bear most of the costs of reclamation but only capture a fraction of the benefits of these activities, there is an incentive to shirk. As time goes on, and the end of the extraction period approaches, operators could conceivably decide that it is in their best interest to declare bankruptcy instead of undertaking the required reclamation activities. This decision would only be revealed to others (including regulators and the public in general) at the time of the declaration of bankruptcy, hence the asymmetric information problem. Responsibility for undertaking the necessary reclamation work would revert to the public.[27]

In addition to the kinds of strategic issues outlined above, operator bankruptcy could also result from rational responses to unexpected exogenous events. From the shareholders' perspective, the best response to a specific event (or events)—a collapse in the market for bitumen (or SCO) or a major leak from a tailings pond, for example—would be to have the affected operator(s) declare bankruptcy. While there would be no strategic or asymmetric information aspects in such cases, the outcome would still be that operators facing this kind of situation would not be in position to undertake and finance the necessary reclamation work, which would revert to the public.

11.3.3 Financial Security for Assuring Reclamation

Are there characteristics of the industry or of the regulatory system in place in Alberta that act to dampen the incentives for operators to shirk on reclamation activities or, more generally, to fail to undertake such activities? Arguably aspects of both the industry and the regulatory system indeed act to reduce these incentives. First, to the extent that operators hold interests in other oil sands properties or intend to undertake more activities in this sector in the future, they will no doubt realize that the kind of strategic bankruptcy declaration described above could very well entail additional costs. In particular, departments and regulatory agencies of the Government of Alberta should be reluctant to approve any future activity plans by an entity engaging in this type of behaviour. Operators need to consider a decision to declare bankruptcy to avoid reclamation liabilities as part of a series of

[27] If the industry were to attract operators who, from the outset, would intend to shirk on reclamation activities, then the relevant asymmetric information problem would be one of adverse selection.

interactions with provincial government departments and regulatory agencies, rather than a one-time economic decision.

Furthermore, the Government of Alberta has acted to address the consequences of operators potentially failing to undertake the required reclamation activities through legislative and regulatory measures. In particular, operators are required to post with AENV or the ERCB some form of financial security deposits to cover at least part of the cost associated with meeting the reclamation conditions identified in the approval for each site. The intention is to ensure that sufficient funds are available for the provincial government to undertake the necessary reclamation activities in the event that it proved impossible for operators to do so (as a result of a bankruptcy, for example). Acceptable forms of financial security include, among others, cash, cheques, government bonds, and irrevocable letters of credit or of guarantee (AR 115/93, section 21).

The ERCB operates three programs aimed at identifying the security deposits that must be provided by Alberta's upstream oil and gas industry, here defined to include in situ oil sands activities (but to exclude surface mines). The *Licensee Liability Rating Program* (LLR) applies to wells, pipelines, and most facilities. Larger facilities, including in situ central processing facilities with design capacities in excess of 5000 cubic metres per day, are covered by the *Large Facility Liability Management Program* (LFP). Finally, oilfield waste management facilities are covered by the OWL (*Oilfield Waste Liability*) program.[28] All three programs are integrated as far as the determination of required security deposits is concerned.

Broadly speaking, the key calculations can be described as follows. For each firm, the deemed assets and deemed liabilities associated with each program are first calculated separately. To avoid double (and triple) counting, deemed assets in each program are based on an estimate of the cash flow generated by three years' worth of production of relevance to the program in question (bitumen production in the case of the LLR and third-party SCO production for the LFP, for example), valued at five-year industry-wide average netbacks (firm-specific netbacks are allowed under certain circumstances). Deemed liabilities in each program are defined as the undiscounted estimated costs of dealing with the firm's suspension, abandonment, remediation, and reclamation liabilities in a way that would meet regulatory requirements (and thus allow AENV or SRD as appropriate to issue a reclamation certificate). These calculations can be based on cost estimates derived in consultation with industry (as in the case of the LLR program, for example) or on facility-specific estimates (for the LFP).[29]

Deemed assets are then summed across all three programs and expressed as a fraction of total deemed liabilities to form a ratio called "liability management rating" (LMR). To the extent that a firm's LMR falls below a specified threshold value (currently set equal to 1.0), then a security deposit (now considered a deemed asset of the firm in question) of a size sufficient to bring the calculated LMR up to the threshold value must be deposited with the ERCB. Firms are allowed to provide additional security, at their discretion; in some cases (ERCB-designated problem sites, for example), the Board

[28] For details on these three programs, see ERCB (2009a, b, c).
[29] The approach to be used in calculating site-specific deemed liabilities is detailed in ERCB (2005).

can request additional security. Information on the forms of financial security acceptable by the ERCB and a template for an irrevocable letter of credit that meets all Board requirements are provided in ERCB (2008).

These calculations are updated every month and can lead to adjustments in the size of security deposits, as warranted. A summary report on the ERCB's liability management programs is available on the Board's website, which includes, for each firm, the LMR value and an indication of whether a security deposit is held by the ERCB on its behalf (all other firm-specific information—deemed assets and liabilities and the size of any security deposit, among other things—is treated as confidential information by the ERCB). For May 2010, this report[30] indicates that total deemed liabilities for the LLR and LFP programs[31] amounted to some $16.4 billion. The total amount of security deposits held by the ERCB is listed as $40.9 million, or approximately 0.4% of total deemed liabilities.

In the event that a licenced operator fails to complete the required suspension, abandonment, remediation, and reclamation activities (in the case of a bankruptcy, for example), the ERCB can use the firm's security deposit to fund the necessary work. To the extent that the deposit is insufficient to cover all of the relevant costs, then an additional mechanism of application to the entire Alberta upstream oil and gas industry—the "Orphan Fund"—is invoked. In cooperation with two key industry organizations (the Canadian Association of Petroleum Producers and the Small Explorers and Producers Association of Canada), the ERCB has established the Alberta Oil and Gas Orphan Abandonment and Reclamation Association (known as the Orphan Well Association [OWA]), a non-profit organization that operates under the delegated authority of the Board. Every year, the OWA prepares a budget that identifies proposed abandonment and reclamation activities relating to sites for which there is no legally responsible or financially able party—"orphan" sites. Once this budget is approved by OWA members, the ERCB collects an activity-adjusted orphan levy on all relevant oil and gas industry participants and makes the funds available to the OWA which then ensures that the necessary abandonment and reclamation activities are undertaken. According to the Alberta Oil and Gas Orphan Abandonment and Reclamation Association (2009, "Statement of Operations"), the Association's expenditures for fiscal year 2008–09 were $13.1 million, of which about 90% ($11.2 million) was spent on properly abandoning and reclaiming orphan oil and gas sites in Alberta.

Security deposits are also collected for oil sands surface mines, under a program administered by AENV.[32] Every year, individual operators provide AENV with an estimate of the expenditures necessary to reclaim the land surface disturbed by oil sands mining activities to the end of the next calendar year (i.e., estimate in 2010 what the 2011 costs would be), which in turn determines the amount of financial security that must be deposited with AENV. From year to year, the amount of financial security required is adjusted to reflect changes in expected reclamation costs (due to expanded production, for example) less the reduction in reclamation liability due to work completed since the last estimate. However, future reclamation costs involving EPLs (Section 8.2.2.2) specifically are difficult to estimate, given the high level of uncertainty over the costs and viability of EPLs as

[30] Available online at: http://www.ercb.ca/docs/data/facilities/LLR_Report_May2010.pdf (last accessed on May 25, 2010).
[31] The ERCB is in the process of completing the integration of the OWL program with the LLR and the LFP.
[32] Note that this program applies more broadly than only to the oil sands industry; it also covers coal mining activities, among others.

remediation and reclamation tools. Presenting a more detailed description of AENV's financial security program is difficult because details about its operations are not as readily available to the public as they are for the comparable ERCB program.

Nonetheless, it is clear that, in contrast to the ERCB-administered program for in situ operations, security deposits in the case of oil sands surface mines reflect only reclamation liabilities. However, financial security must be provided for all estimated liabilities, and are not adjusted for related deemed assets. Note as well that only surface mining activities are covered by this program; no financial security is required for bitumen extraction plants and upgraders, for example—another difference with the treatment extended to in situ operators. Finally, surface mine operators do not pay into the province's Orphan Fund, and so access to this Fund would not be possible if security deposits to prove insufficient to cover the costs of required reclamation work made necessary by the unwillingness or inability of any operator to perform.

According to AENV (2009), the total amount of financial security on deposit with the Ministry as of March 31, 2009 was slightly more than $1.1 billion. These funds held by AENV are distinct from those mentioned earlier that are held by the ERCB. Oil sands activities accounted for $820.5 million, or approximately 73% of the total, and the entire amount deposited by operators in this industry took the form of irrevocable letters of credit or other bank guarantees. This report also identifies the security deposit amounts posted by each operator (or their partners) for each major oil sands surface mining project, as shown in Table 10.1.

Over the years, questions have been raised about the adequacy of the dual financial security process outlined above. For example, Grant et al. (2008, section 4.4) worry that the approaches used by both ERCB and AENV involves only government/regulator–industry consultations and thus exclude public participation. As far as AENV is concerned, this state of affairs is, at least in part, linked to the provisions of EPEA, which state that, under certain circumstances, information relating to an individual operator's security deposit that is provided to the Ministry can be kept confidential at the request of the operator (section 35(4) of the *Act*). AENV has ruled that all such information will be held in confidence, with the exception of that provided in AENV (2009), which clearly limits the extent of public participation possible.

Grant et al. (2008, section 4.4) also provide some evidence suggesting that the amounts required to be deposited could well be too small, thus leaving a potential financial liability for the public. Such shortfalls in the size of security deposits would be consistent with the U.S. experience in coal and hard-rock mining, as documented by, among others, Webber and Webber (1985) and Barlow (2006), respectively. In a recent review of the situation in Québec, the Auditor General of that province (Vérificateur général du Québec 2009, item 2-75, p. 2–22) came to a similar conclusion: the financial security deposits linked to the specific mining sites considered were deemed to reach only some 69% of reclamation-related liabilities.

More generally, it is clear that Canada has a long tradition of insufficient financial security for environmental liabilities (including reclamation) associated with contaminated sites, including mines. In 2002, for example, the Commissioner of the Environment and Sustainable Development (Office of

the Auditor General of Canada 2002a, b) considered the issue of federal contaminated sites and concluded that public investments will be required to address the issue: "*[w]e estimate that the total cost to Canadians to deal with these sites represents billions of dollars*" (Office of the Auditor General of Canada 2002b, p.1). The Commissioner (Office of the Auditor General of Canada 2002a) also concluded that, at least until 1993 when the relevant federal legislation was changed, the Government of Canada did not collect sufficient security from mine operators in Canada's North to cover all of the costs related to the reclamation and closure of mines, so that a public liability was created in situations where mine operators were unable or unwilling to carry out reclamation work (such as in situations of operator bankruptcy and mine abandonment). The existence of a public liability linked to the reclamation of abandoned and orphaned mines in Canada is confirmed by work undertaken on behalf of the National Orphaned/Abandoned Mines Initiative (NOAMI), a joint federal–provincial undertaking, which recognizes the existence of some 10,000 abandoned mine sites in Canada and a reclamation-related public liability "*approaching several billion dollars*" (Cowan and Mackasey 2006, p. 2).

The Auditor General of Alberta has also repeatedly expressed concerns about the financial security process managed by AENV. Specifically, the issues of whether the process was consistently applied and whether the amounts of financial security required were sufficiently large were raised in the 1998–99 report (AGA 1999, pp. 158–159). The same report also noted that AENV had taken the lead to develop, in consultation with other government agencies and interested stakeholders, a "*Financial Security Risk Assessment Model*" that would be used to determine financial security amounts in a prudent and consistent manner. This kind of systematic approach would, at least on the surface, appear to be consistent with a recommendation of a committee of the U.S. National Research Council (NRC 1999, Recommendation 1, pp.93–95) on the determination of financial assurance for reclamation activities linked to hardrock mining on US federal lands.

A few years later, the Auditor General of Alberta (AGA 2001, p.90) noted that: "*…the Model had been rejected by Department executives,*" which led to a restatement of concerns about the financial security process. This time, a more specific statement was also made (*ibid.*): "*[i]n general, the Department [AENV] requires companies to post security equal to the full cost of recovering the public land that they will disturb. However, there are a few large land-disturbing industries (oil sands and coal mines) that are not charged full cost.*" It was again recommended that the financial security process be revised to meet the concerns first raised in the 1998–99 annual report.

These issues have been raised regularly in the Auditor General's reports for the last decade, without ever having been addressed to that agency's satisfaction. In the most recent report (AGA 2009, p. 208), the situation is described in the following terms:

> In our *2004–2005 Annual Report*…we recommended that the Department [AENV] implement a system for obtaining sufficient financial security to ensure that parties complete the reclamation activity that the Department regulates. We noted that there were still many inconsistencies in how financial security was posted for oil sands and coal mines. Some sites posted security under prior legislation and that security has been continued under existing legislation. The result is that some sites had security based on

> production and not on the full cost of reclamation, as currently required by *EPEA* [*Environmental Protection and Enhancement Act*]. Some sites used outdated information to determine their estimated full cost of reclamation. Some estimates did not include all required costs. As a result of these inconsistencies, the sufficiency of security for the completion of reclamation was not ensured.

Reference to previous legislation in the determination of security deposits for some long-standing oil sands mining operations is explicitly made in section 18(3) of the *Conservation and Reclamation Regulation* (AR 115/93). In such cases, the relevant provisions are those of AR 172/77 (as amended by AR 471/78), whereby the total security deposit required of an oil sands mine is set at a flat amount of $100,000 or $250,000 (depending on daily production volumes), plus $0.03 / bbl ($0.19 / m^3) of SCO produced annually. As noted by the Auditor General, production here determines the size of the financial security required, which is thus not linked to the firm's estimated reclamation liabilities.

In apparent recognition that at least some of the Auditor General's concerns about the financial security program still need to be addressed, the Government of Alberta (Gov AB 2010, p. 166) in its 2010 Budget Summary addressing the Auditor General's Recommendations indicates that it accepts the Auditor General's oft-repeated recommendation and stated that "*The Department* [Environment] *is actively engaged with industry to develop a system that will see better reclamation security cover. The new policy is expected to be in place in 2010*." The need to "enhance existing mining liability management programs to further protect Albertans from financial liabilities related to reclamation" has also been explicitly identified as an objective by the Government of Alberta (Gov AB 2009b, item 1.2.4, p. 18). However, similar statements have been made by the provincial government on numerous occasions since the Auditor General first raised these issues in 1999 and that, as of the time of writing, the development and implementation of a new policy in this area had yet to occur.

Key issues relating to oil sands reclamation activities can be characterized as follows. Some oil sands operators may be unwilling or unable to undertake the required reclamation activities. In such cases, responsibility for undertaking the necessary reclamation work would rest with the provincial government who would then be expected to access the financial security previously deposited with the ERCB or AENV to cover the expenses associated with that work. To the extent that the expected costs of reclamation had been understated during the productive years, the financial security deposit will be inferior to that needed to cover all of the expenditures required to meet the objective. Consequently, a net burden would be imposed on the Orphan Fund (in the case of in situ operations) and more generally on the public purse (i.e., the Government of Alberta). This type of potential outcome arguably lies at the heart of concerns expressed by Auditor General of Alberta (AGA 1999) and Grant et al. (2008). Past experience suggests that operator abandonment of non-reclaimed (or "orphan") properties has been a significant expense for Alberta's conventional oil and gas industry.[33] The Alberta Oil and Gas Orphan Abandonment and Reclamation Association (2009, Table 6, p. 13), for example,

[33] Note as well that as part of an incentive program for the province's energy sector announced in March 2009, the Government of Alberta provided a sum of $30 million to help finance the activities of the Orphan Fund (Alberta Energy 2009).

reports the existence of some 549 oil and gas wells that have been abandoned by their operators and for which a reclamation certificate had yet to be issued.

The experience of Alberta's coal mining industry might be of greater relevance to the case of oil sands surface mining activities. During the last decade, on only one occasion has AENV had to access a security deposit due to a financial exigency experienced by a coal mining firm. In 2000, Smoky River Coal Ltd. declared bankruptcy and AENV cashed the letter of credit previously deposited by the company, as noted in AENV (2001, p. 63). Over the next few years, environmental monitoring, reclamation planning, and work related to public safety assurance were undertaken and paid for by AENV.[34] Eventually, a portion of the site was acquired by a different company and returned to operation in mid-2004, as pointed out in Jen (2005, p. 5.4). As a result, reclamation activities for that portion of the site became part of the operating plans of the new owner.

The *nature* of the financial securities typically accepted by both the ERCB and AENV also addresses the moral hazard problem described earlier. Recall that in the case of oil sands operations, *all* of the financial security deposited by operators takes the form of irrevocable letters of credit or other bank guarantees. This creates a relationship between the issuer of the letter of credit and the ERCB or AENV ("the beneficiary"). In the advent of bankruptcy by one of the operators, any letter of credit deposited with either of these agencies is payable by the issuing financial institution at the request of the beneficiary; neither the ERCB nor AENV would be left holding claims against the assets of a bankrupt entity: letters of credit are claims against the assets of the financial institutions that issue them. As far as reclamation expenditures are concerned, the operator's bankruptcy risk has thus been assumed by the issuing financial institution, limited only by the amount of the letter of credit. As a result, in addition to the possibility that the available security is not sufficient to cover all relevant reclamation costs, the key remaining financial risk for the beneficiary of the letter of credit is that associated with the issuing financial institution itself. Note, however, that the ERCB (2008, p. 2) currently accepts letters of credit issued by the Alberta Treasury Branch as financial security for in situ operations. Since the Government of Alberta owns the Alberta Treasury Branch, accepting letters of credit issued by this financial institution effectively entails the Government of Alberta taking on ultimate responsibility for the financial risk associated with these financial instruments. Finally, since the letters of credit issued on behalf of firms involved in surface mining projects tend to be for considerable amounts (as indicated in Table 10.1), only large and well capitalized institutions can be relied upon to deliver on such commitments. From this viewpoint, it might well be advisable for AENV to consider carefully whether the ERCB practice of accepting letters of credit issued by "*Alberta-based credit unions*" (ERCB 2008, p. 2) as financial security for in situ operations would be appropriate, from a risk management perspective, for surface mining operations.

[34] On this, see Ministry of Environment (AENV 2001, p.49; 2002, p. 22).

Table 11.1 Security deposits posted with AENV – oil sands mining projects
As of 31 March 2009; millions of current Canadian dollars

	Project	Company	Amount
Syncrude	*Mildred Lake*	Canadian Oil Sands	67.4
		ConocoPhillips Canada	16.6
		Imperial Oil	45.8
		Mocal Energy	9.2
		Murphy Oil	9.2
		Nexen Oil Sands	13.3
		Petro-Canada	22.0
	Total – Syncrude		183.5
Albian Sands	*Jackpine*	Chevron Canada	10.8
		Marathon Oil Canada	10.8
		Shell Canada	32.5
	Muskeg River	Chevron Canada	17.1
		Marathon Oil Canada	17.1
		Shell Canada	51.4
	Total – Albian Sands		139.7
Fort Hills		Petro-Canada	41.2
		Teck Cominco	13.7
		UTS Energy	13.7
	Total – Fort Hills		68.6
Kearl	*Kearl*	Exxon Mobil Canada	28.6
		Imperial Oil Resources	69.8
	Total – Kearl		98.4
Horizon	*Horizon*	Canadian Natural Resources	45.1
Suncor	*Steepbank/Millenium*	Suncor Energy	285.0
		Total	**820.3**

Source: AENV (2009, Supplement to the Annual Report)

11.4 Impact Assessment and Environmental Management

11.4.1 Environmental Impact Assessment

As discussed in Section 5, oil sands operations must undergo a formal approval process (Figure 5.1), of which an environmental impact assessment (EIA) is an integral part. EIAs typically consider activities in the area around the project, the project itself, a combination of economic, environmental and social issues, and resource sustainability. Project proponents must provide an assessment of all of the factors linked to the proposed activities.

The practice that has emerged in the oil sands industry typically involves development by AENV of terms of reference (ToR) for each project's EIA report (finalized following public consultation). More details on the process, which may also involve the CEAA are provided in Section 5. The public consultations can lead to more submissions by proponents before the EIA report is considered final. The final submission and the panel's EIA review are treated as input into the ERCB's decision as to whether, and under what conditions, a specific project is allowed to proceed.

11.4.1.1 Socio-Economic Factors

In addressing socio-economic factors in oil sands EIAs, we considered EIA-related materials associated with three recent oil sands development applications considered by the ERCB in joint panels with the CEAA: Imperial Oil Resources' Kearl surface mine project (ToR April 22, 2004), Albian Sands Energy's proposed expansion of the Muskeg River surface mine (ToR February 28, 2005), and Deer Creek Energy's Joslyn surface mine project (ToR September 29, 2005). Information on these projects can be accessed through the CEAA website.[35]

Our assessment of the treatment of socio-economic factors in these EIA reports will address three sets of issues:

- The content and analytical quality of the materials submitted by proponents, given the ToR provided by AENV.
- The ToR themselves, in light of existing guidelines and practices.
- The contribution of the EIA reports to the regulator's information needs for making decisions in the public interest.

To facilitate the exposition of this subject, an extract dealing with socio-economic factors from the ToR for Albian Sands Energy' proposed expansion follows. Corresponding statements in the ToR for the Deer Creek Energy proposal use "Project" instead of "Expansion," and in the earlier Kearl project ToR the last item was not included.

The ToR (AENV 2005, pp. 26–27) requires Albian Sands Energy to provide information on the socio-economic effects of the expansion by discussing the following:

[35] For example, for the Shell/Albian Muskeg River Mine: http://www.ceaa-acee.gc.ca/050/document-eng.cfm?document=16923)

- Selection of study areas, information sources, and assessment methods.
- Number and distribution of people who may be affected by the proposal.
- Social impacts of the expansion on the study areas and on Alberta, including local employment and training; local procurement; population changes; demands on local services and infrastructure; regional and provincial economic benefits; trapping, hunting, and fishing; and effects on First Nations and Métis (i.e., traditional land use and culture).
- Economic impacts of the expansion on the study areas and on Alberta, regarding capital, labour and other operating costs and revenue from services; discussion of Albian's policies and programs regarding use of local, Alberta, and Canadian goods and services; an estimated breakdown of Alberta, other Canadian, and non-Canadian industrial benefits from project management and engineering, equipment and materials, construction labour, and total overall project.
- Employment and business development opportunities the expansion may create for First Nations, Métis, local communities and the region; employment type and number of employees regarding construction and operational workforces; source of labour for the proposed expansion.
- Strategies to mitigate socio-economic concerns raised by the Regional Municipality of Wood Buffalo and other stakeholders in the region; a discussion on potential impacts to housing availability and social ramifications of that impact; documentation of work with other industry partners and the Regional Municipality to continue use and development of the urban population prediction model developed for baseline socio-economic purposes.
- Impacts of the proposed project on potential shortages of affordable housing and quality of health care services; identification and discussion of mitigation plans to address these issues; a summary of any discussions that have taken place with the Municipality and the Regional Health Authority concerning potential housing shortages and health care services respectively.

Each EIA report consulted in our review included a concordance that identified where each specific issue (typically at the item or sub-item level) included in the ToRs was addressed in the documentation submitted. For the reader, this is an extremely useful feature since EIA reports tend to be voluminous. In the Kearl proposal, for example, the initial submission consisted of slightly more than 8,000 pages in nine volumes. Supplementary information provided by the proponent was about 1,400 pages in two volumes. The concordance is thus a very useful guide to treatment of individual issues provided by EIA reports.

While information on socio-economic factors included in each EIA report consulted was easily accessible, differences in the treatment of these factors were noted across the three reports. For example, detailed discussions of socio-economic factors were included in the main text of the Kearl and Muskeg River EIA reports, while the Joslyn report provided a more cursory discussion of these factors in the main body of the text and relegated the detailed consideration to an attached document prepared by a consulting firm.

In all cases considered, however, the underlying approach to consideration of socio-economic factors was quite similar: the current setting (including all approved developments) was described, then the

project was introduced and its anticipated impacts (focusing on aspects included in the ToRs) were identified. Anticipated impacts of the project were also typically provided for a case in which all planned oil sands developments were included. To the extent that the project was expected to create pressures on the local or regional economy, mitigation measures were identified to address these situations. The quantitative information provided typically revolved around income (payment) flows, employment, and population effects of the project, for both construction and operations phases. More detailed information on transportation related impacts (e.g., traffic flows) were provided in the materials provided in support of the Joslyn project. In general, however, most of the anticipated impacts were described in words and no quantitative "value" was associated with these.

The same can be said about the mitigation measures proposed to address the socio-economic pressures anticipated to be associated with the projects: descriptions of the measures and their expected effects rarely (if ever) included values for the costs and benefits of enactment.

Overall, the EIA reports provide some information on each of the socio-economic dimensions addressed in the ToR, as the concordance tables make clear. Nonetheless, areas of concern were noted in the course of our assessment; some examples of these are provided below. For instance, some of the quantitative information provided is difficult to assess: in the case of the Joslyn EIA report, it is not clear whether dollar values are expressed in nominal or real (i.e., adjusted for inflation) terms. Assumptions used in some of the present value calculations are not always clearly identified: assumptions about general price inflation and future oil prices are not clearly labeled in either the Kearl or the Muskeg river reports, which makes it difficult to interpret the present values of royalty and tax payments provided, for example.

There are statements in the Muskeg River and Joslyn reports for which adequate support is lacking in the documentation provided. Given the paucity of quantitative information provided on impacts, it is difficult to see how the following statement reflects the information provided: "*The SEIA [socio-economic impact assessment] estimates the net social benefit associated with the expansion project.*" (Shell Canada Limited 2005, p. 17-1). The same can be said about this conclusion drawn in the Joslyn report: "*From a socio-economic point of view, the benefits from the Joslyn North Mine Project – Phase 1 and 2 accruing to the local area and region will outweigh any adverse effects*" (Deer Creek Energy Limited 2006, p. D.9–11).[36]

More generally, given the focus on income (payment) streams associated with capital and operating expenditures, the reports are open to the criticism that *higher* expenditures associated with a project of a *given* size in output terms would be a "good thing" since these would generate higher payment flows. In other words, it can be argued that not enough attention is paid in the reports to the "cost" side of the ledger, with the result that the reader is left with the impression that higher expenditures for a given facility could well be "good" simply because these generate greater payments to labour, etc.

As noted earlier, each of these projects was considered by a joint CEAA/ERCB panel. In each case, the following statement can be found in the agreement that established the joint panel: "*the assessment will*

[36] This statement is repeated integrally in the consultant reported embedded in the documentation submitted by the project proponent; see IPS Consulting Inc. (2006, p.48).

include a consideration of the factors listed in subsection…of the Canadian Environmental Assessment Act, namely: a. the environmental effects of the Project, <u>including the environmental effects of malfunctions or accidents</u> that may occur with the Project…b. the significance of the effects referred to in paragraph a);…d. measures that are technically and economically feasible and that would mitigate any significant adverse environmental effects of the Project…" (CEAA and AEUB 2006, Appendix; emphasis added). The assessment of these potential effects included in the EIA reports, however, does not extend to their impacts on socio-economic factors. This, in turn, is part of a more general characteristic of the reports, namely that these generally include little in the way of sensitivity analysis, which is typically part of any standard economic analysis of projects.

As far as the overall structure and contents of the ToR themselves, there is no shortage of "guidelines," "principles," and similar constructs available for "environmental impact assessments," "socio-economic impact assessments," "social impact assessments," and the like. In the course of our own work, we consulted documents prepared by the International Association for Impact Assessment (IAIA 1999, 2003), the International Association of Oil & Gas Producers (OGP 1997), the International Petroleum Industry Environmental Conservation Association (IPIECA 2004), the IPIECA and OGP (2002), and the World Bank (1999). There is also an OECD-sponsored document (Pearce et al. 2006) that helps set a number of assessment process and tools (including EIAs) in the context of benefit-cost analysis.

Most of these documents are written at a very high level of generality and so are arguably not particularly helpful when trying to focus on specific items and provisions. However, most of these explicitly (or implicitly) recognize that the identification of impacts is just that: identification, with no "value" components provided. These documents are thus effectively concerned with methodologies to assist in compiling lists of possible impacts; some also extend to include the identification of mitigation measures. This approach is consistent with the descriptive statement on EIAs included in Pearce et al. (2006, pp. 270–271).

The key exception here is the World Bank (2009, especially chapters 1 and 4), which provides much more detailed guidance for environmental assessment and is clearly designed to get the project proponents to put values on impacts whenever possible and to list those impacts for which a value cannot reasonably be assigned. The focus is then moved from "benefits" without reference to costs, on to "net benefits" with full consideration given to the opportunity costs of activities, actions, and their consequences. That being said, the basic environmental assessment structure recommended in this World Bank document is very similar to that provided in the ToR for the three oil sands project considered. Basically, the World Bank document recommends a deeper analysis, but identifies for essentially the same sets of factors. One key exception has to do with sensitivity analysis, which is explicitly included in the World Bank methodology—and especially so in the case of projects involving "*industrial facilities,*" defined to include "*a wide variety of mining transportation, energy generation…with inherent hazards which require careful management*" (World Bank 2009, chapter 10, p. 1) and thus of relevance to oil sands activities. Overall, this suggests that as far as the consideration of socio-economic factors is concerned, the World Bank environmental assessment process is much

more rigorous for projects under active consideration for Bank lending than is the EIA process that applies to oil sands projects being considered for approval.

As far as decisions in the public interest are concerned, Pearce et al. (2006) are quite clear: EIAs might well be necessary for such decisions, but—at least as far as socio-economic dimensions are concerned—these do not provide a sufficient base of information adequate to support public-interest decision-making. The World Bank (1999) basically starts from this premise as well. It is also consistent with what the IAIA (2003, p. 6) calls an international principle "*in common usage rewritten to apply more directly to social issues,*" namely:

> *Internalization of Costs.* The full social and ecological costs of a planned intervention should be internalized through the use of economic and other instruments, that is, these costs should be considered as part of the costs of the intervention, and no intervention should be approved or regarded as cost-effective if it achieves this by the creation of hidden costs to current or future generations or the environment (IAIA 2003, p. 7; emphasis in original).

The key issue is thus the need for analytical rigour and completeness, especially in getting proponents to assess (whenever possible) the costs associated with the environmental (and human health) aspects that would result from the project going ahead. It is understood that not all costs can be quantified, but—to put it simply—"*do the best you can, and list all the other impacts*" is the approach recommended. Then, integrate mitigation measures into the analysis and include their anticipated costs and benefits (the latter in the form of expected reductions in environmental and human health costs), and compare the anticipated benefits of the project with the "full" anticipated costs. In that framework, sensitivity analysis is an integral part of what needs to be done: the robustness of the project's benefits *relative* to its full costs must be assessed.

In the end, the key "public interest" question can be stated as follows: on balance, is the project expected to provide a net positive contribution to the welfare of society as a whole? As far as socio-economic information and analysis are concerned, the recent oil sands EIA final reports we reviewed fall short of providing what Pearce et al. (2006) deem necessary to allow for an adequately informed determination of whether a given project is in the public interest.

It is interesting to note, however, that some twenty years ago the ERCB (jointly with Alberta Environment) issued guidelines on the expected contents of applications for bitumen production and upgrading projects that include provisions aligned with the World Bank practices outlined above and the recommendations in Pearce et al. (2006). Specifically, ERCB (1991) outlines the regulators' expectation that such applications will include "*an evaluation of the commercial viability of the project*" (p.24) as well as "*a summary of any additional quantifiable public benefits and costs incurred during the construction and operation of the project*…[and] *a summary of any non-quantifiable public benefits and costs incurred each year during the construction and operation of the project*" (p.26). While these guidelines continue to be in effect, applications for bitumen production and upgrading projects filed over the last decade at least have not included this kind of information, but have focused instead on meeting the informational requirements identified in the ToR for the project's EIA, as

drafted by Alberta Environment and, when appropriate, incorporated into the agreement establishing a joint CEAA/ERCB panel. Overall, this means that the assessment of socio-economic factors associated with proposed oil sands projects has been less complete and rigorous than that proposed in ERCB (1991). The issues raised above as to how current assessment practices in Alberta fall short of those applied by the World Bank and also fall short of providing what Pearce et al. (2006) consider to be the information necessary to determine whether a project is in the public interest would not arise if the provisions of ERCB (1991) were applied.

11.4.1.2 Biophysical Environmental Factors

Current practice to address water quality and quantity issues during an environmental impact assessment, can be summarized by the following steps:

- Establish a baseline for water quality and quantity, both for surface water and groundwater. Establishing the baseline involve conducting hydrological and hydrogeological characterizations, which consists of collecting available data, performing supplemental field investigations, and summarizing the hydrological and hydrogeological contexts for the area concerned by a project.
- Predict the impact of future operations in water quality and quantity using mathematical models, most commonly numerical models.
- Propose mitigation measures for cases where a regulatory requirement is not met.
- Propose voluntary mitigation measures to diminish the impact of operations, but not in the context of a specific regulation. One example would be to propose to recycle water to reduce groundwater extraction, only, however, where recycling is not necessarily required.
- Propose a monitoring program to follow the evolution of water quality and quantity. For groundwater, a monitoring program would consist of installing observation wells near SAGD wells, taking regular water level measurements and sampling groundwater for chemical analyses.

Most EIAs conducted for oil sands projects have detailed information on the soil, hydrologic, faunal, and floral components of the ecosystems to be disturbed. In fact there is much repetition in this area, with numerous EIAs repeating assessments that have already been well documented. This documentation focuses on what is in the area and what may be impacted by oil sands development. However, few studies rigorously address what has actually occurred in previous developments and what can be reasonably expected to be developed in large scale reclamation efforts.

Although individual components of an ecosystem to be developed for oil sands operations have been documented and quantified, few EIAs have provided any focus on the ecological capacity in the region to identify limits that need to apply to individual project approvals. For example, some studies have identified critical faunal movement patterns but have failed to address them in the overall regional context.

There are some encouraging signs of seeking evidence from previous EIAs such as the proposed 2010 review of EIA predictions regarding aquatic issues being done under the RAMP technical review (RAMP 2009). Environment Canada has also funded studies that have sought to extract information from past EIAs to assess evidence for controlling fugitive emissions from mine faces and tailings ponds (Worley Parsons 2009), and a series of studies addressing options for controlling benzene emssions and particulate matter (Dillon 2008, 2009) and metals and PAH (Jacques Whitford 2009). Unfortunately, the monitoring evidence which oil sands operators are obliged to collect under the EPEA approvals are not accessible for validating EIA predictions and performance of emissions control technology. This limitation on data access severely compromises the ability to judge current reality against past EIA predictions.

The following groups are involved in monitoring the environmental performance on oil sands developer commitments:

- The Wood Buffalo Environmental Association (WBEA) is a collaboration of industry, government, environmental groups, and Aboriginal stakeholders that have been monitoring air quality in the region since 1997. According to the information available on its website, the WBEA have 15 monitoring stations and 27 passive monitoring stations (see Section 7).

- The Regional Aquatics Monitoring Program (RAMP) is a multi-party environmental monitoring program that determines, evaluates, and communicates the state of the aquatic environment and any changes that may result from cumulative resource development within the Regional Municipality of Wood Buffalo (see Section 8).

- The Cumulative Environmental Management Association (CEMA) studies the cumulative environmental effects of industrial development in the region (see Section 11.4.4).

Member listings of these various organizations are available in Appendix A7.

11.4.1.3 Public Health Factors

The Alberta Environment Ministry has established an Air Quality Management System in conjunction with the multi-stakeholder Clean Air Strategic Alliance (CASA) to protect and enhance air quality and the Alberta Water for Life Strategy working with watershed councils to protect the quality and supply of safe drinking water.

The health component of EIAs takes the form of a quantitative health risk assessment, focusing on health issues that may arise from chemical exposure. In EPEA the integral relationship between human health and the environment is recognized and co-operation is expected among ministerial portfolios in promoting human health through environmental protection.

EIAs are required by EPEA for major projects as outlined in Section 5. Health is one component of EIAs where it takes the form of quantitative health risk assessment, focusing on health issues that may arise from chemical exposure. EPEA, section 11, states that "*The Minister shall, in recognition of the integral relationship between human health and the environment, co-operate with and assist the*

Minister of Health and Wellness in promoting human health through environmental protection." Section 49 of the EPEA outlines the information to be contained in the EIA report, sub-section (g), states that "*An environmental impact assessment report must be prepared in accordance with the final terms of reference issued by the Director under section 48(3) and shall include the following information unless the Director provides otherwise: an identification of issues related to human health that should be considered*" (Gov AB 2009a).

Within the Alberta framework for EIAs, health is not the subject of a separate evaluation. The EIA is an integrated study of the possible effects on the environment in the broad sense, including the study of impacts on different environmental media, biodiversity, and human health. Consequently, all considerations for health effects of any oil sands project fall under the EIA process.

Health issues considered in oil sands projects EIAs have mainly been covered under a heading of environmental health which relies on the use of predictive health risk assessments estimating the likelihood of adverse health effects that may result from future exposures to contaminants released in the environment by the projects. This type of assessment is best suited when done chemical-by-chemical, media-by-media, or source-by-source. However, this approach conveys a very limited view of health determinants, health status and risk factors, by restricting risk to chemical contaminants exposure. To be fair, these issues have been major concerns expressed by intervenors at public hearings.

AENV has prepared a guide to assist proponents understanding the content and scope of an EIA report (AENV 2009). Concerning health, the guide specifies in section 4.6, Public Health and Safety Assessment (TOR Section 6):

Proponents should contact Alberta Health and Wellness prior to starting work on the Human Health Risk Assessment to determine the appropriate data, methods and models to use. When commenting on the implications for public health and health delivery, Proponents should specifically reference implications for individual aboriginal communities and groups. Follow-up work proposed to assess potential health impacts could include but is not limited to risk management strategies and human health monitoring.

In section 4.7 concerning Socio-Economic Assessment (TOR Section 7), the guide says:

"*Proponents are encouraged to identify training, employment and business benefits specifically accruing to aboriginal communities in the Study Area where possible*" (AENV 2009). This updated guide on content for an EIA report provides no other specifics on socio-economic assessment (see Section 11.4.1.1). Recent EIAs have provided more comprehensive socio-economic considerations including community services and related indicators that will bear on a broader notion of health. However, the assessments which have been done are not sufficiently comprehensive regarding the full range of relevant indicators, nor have the assessments attempted to analyze quantitative data or make projections of how such indicators will be impacted by project implementation.

AHW leads a multidisciplinary team that conducts the required health impact assessment review within the broader EIA review framework. The team reviews EIA Terms of Reference and EIA Reports. They

identify health concerns, formulate questions for project proponents, decide on the adequacy of responses, and comment on the completeness of the EIA Reports. Before they were dissolved, RHAs had the option of becoming involved with AHW in reviewing both the EIA Terms of Reference and the EIA Report. Regional environmental health staff for AHS could presumably participate in this manner, but the role of regional AHS staff in this regard is not clear from public documentation available at this time.

The federal role in health with respect to EIAs would be exerted if CEAA becomes involved in oil sands EIAs and public hearings (Section 5.3.3 and Appendix A3). Health impacts considered are the ones directly related to an environmental issue. The federal EIA follow similar procedures as the provincial process described earlier. Health Canada has a role as an expert agency to contribute to the analysis process, giving advice on health effects mentioned and mitigation measures proposed in EIAs. CEAA requires that projects having environmental impacts that are to be carried out on a First Nations reserve are subject to an EIA.

11.4.2 Best Practices in EIA Specifically for Health Impact Assessment

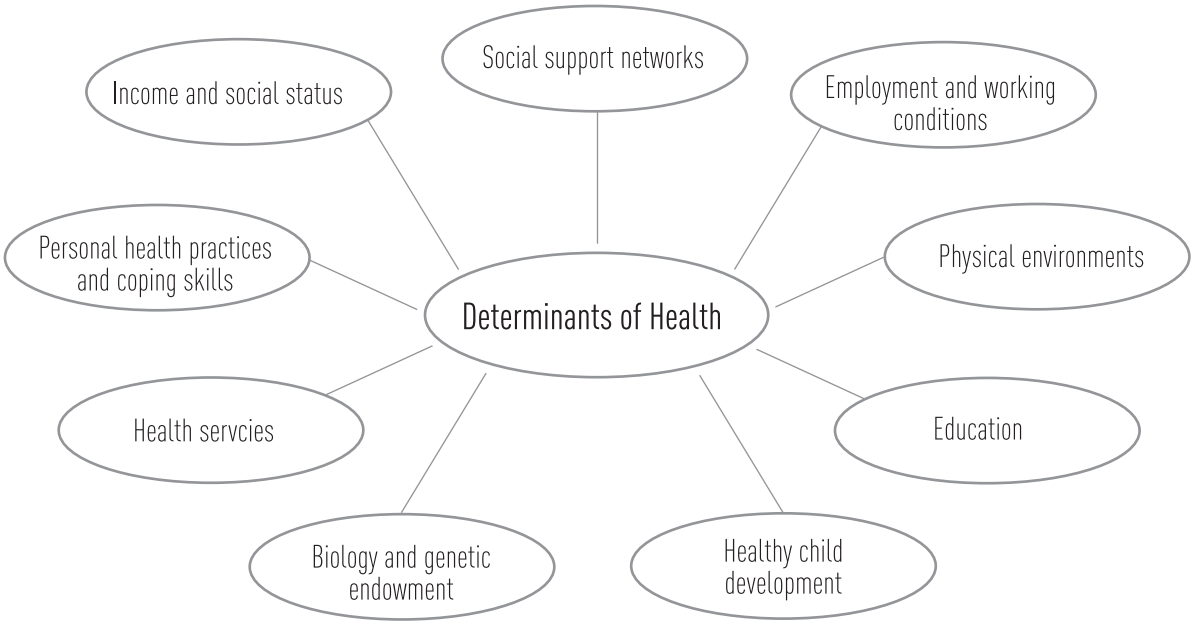
As regulatory and legislative processes very often require long lead times before being updated, several international organizations advocate the use of best practice guidelines to integrate new evidence and technological improvements in every day practice. In this section, the main ideas of a few of these best practices guideline are summarized.

11.4.2.1 Government of Canada and Other Canadian Jurisdictions

The *Canadian Handbook on Health Impact Assessment* was prepared by Health Canada under the general guidance of the Health Impact Assessment Task Force reporting to the Federal/Provincial/ Territorial Committee on Environmental and Occupational Health (CEOH) and a first version was published in 2004 (Health Canada 2004). The CEOH had membership from all provinces and territories, and from the federal government. There was a consensus among all authorities that guidance material on health impact assessment (HIA) within environmental assessment was needed in Canada and that it should include advice on assessing effects on socio-cultural health and occupational health, as well as physical health. Consistent with the WHO's definition of health and the known determinants of health, CEOH adopted a holistic definition of health and clearly indicated that health is more than the absence of sickness and disease; specifically "*health encompasses social, economic, cultural and psychological well-being, and the ability to adapt to the stresses of daily life.*" Figure 11.1 outlines the determinants of health that were identified by the Federal, Provincial and Territorial Advisory Committee on Population Health (1994), including participating members of the province of Alberta. For instance, this approach has been implemented for the last fifteen years in Québec, where EIA guidance from the government includes requirements addressing these various health concerns.[37]

[37] Ministère du Développement Durable et de l'Environnement et des Parcs: http://www.mddep.gouv.qc.ca/evaluations/publicat.htm#msss

Figure 11.1 Determinants of health as identified by the Federal, Provincial and Territorial Advisory Committee on Population Health



The National Collaborating Centre for Healthy Public Policy (NCCHPP)[38] is a national organization in Canada funded by the Public Health Agency of Canada that seeks to increase the expertise of public health actors across Canada in healthy public policy through the development, sharing, and use of knowledge. The NCCHPP held a workshop in 2009 for provinces having an interest in learning more about HIA and to identify potential needs associated with HIA practice. During the first part of the workshop, participants were invited to briefly describe the interest in HIA shown by their respective ministry or government. At the time the workshop was held, Saskatchewan was reported to be making an effort to broaden the scope of health assessments to include the social determinants of health. Also, in Newfoundland and Labrador, there existed extensive collaboration between departments. The *Ministère de la Santé et des Services sociaux du Québec* (MSSS, or Quebec's Ministry of Health and Social Services) adopted section 54 of the *Public Health Act* in 2002. This involved a twofold implementation including the HIA mechanism as well as research on a wide scale. Concern for potential impacts on other sectors is an integral part of every plan and every strategy (NCCHPP 2009).

One section of the guide is concerned with Aboriginal health and traditional knowledge which would clearly be relevant for working in the oil sands.

[38] http://www.ncchpp.ca/2/Home.htm

11.4.2.2 Government of Alberta

The Alberta Health and Wellness website states that: "*The health of a human population depends upon many factors, including personal health attributes or genetic endowment; social and economic conditions; health related behaviour practices; as well as physical, chemical and biological agents in the environment*." In Alberta, public health programs are mandated to address the social, economic, and environmental factors that affect health. Community exposure assessments provide measures of potential exposure to environmental hazards to determine if industrial development is affecting the health of oil sands communities. Also, by identifying differences in disease rates, they are able to detect potential causes for these differences.

However, separate HIAs are not currently conducted in Alberta. Consequently, only contaminant-related assessments have been conducted so far. Limited social and economic conditions are considered in these assessments; thereby the definition of health adopted by Alberta is not fully addressed. Currently, there are no HIA guidelines for assessment of major projects such as oil sands. It appears that a recent provincial health strategy has included as one of its six objectives the reinforcement of public health practices and infrastructure and more specifically through the development of a HIA process for major government initiatives (Gov AB 2008).

If the HIA is performed as part of the environmental impact assessment process, then it should hold to the same standards as a stand-alone HIA.

11.4.2.3 International Association for Impact Assessment (IAIA)

The International Association for Impact Assessment (IAIA) has issued guidance on how to integrate health into impact assessments, mainly in the context of development planning. This concise document (four pages) was published in 2006 by the IAIA, in collaboration with the WHO (Quigley et al. 2006). This guidance defines HIA as: "*a combination of procedures, methods and tools that systematically judges the potential, sometimes unintended, effects of a policy, plan, program or project on the health of a population, and identifies appropriate actions to manage those effects.*" According to the international best practice principles described in this publication, one of the guiding principles for HIA is a comprehensive approach to health, emphasizing that physical, mental, and social well-being is determined by a broad range of factors from all sectors of society known as the wider determinants of health. In adhering to this principle, the HIA method should be guided by the following determinants of health: (1) determinants related to the individuals, (2) social and environmental determinants, (3) institutional determinants (shown in more detail in Table 11.2).

Table 11.2 Determinants of health

Categories of determinants of health	Examples of specific health determinants
Individual factors: genetic, biological, lifestyle/behavioural, and/or circumstantial. Some of these factors can be influenced by proposals and plans, others cannot.	Gender, age, dietary intake, level of physical activity, tobacco use, alcohol intake, personal safety, sense of control over own life, employment status, educational attainment, self esteem, life skills, stress levels, etc.
Social and environmental factors: physical, community, and/or economic/financial conditions.	Access to services and community (health, shopping, support, etc); social support or isolation; quality of air, water, and soil; housing; income; distribution of wealth; access to safe drinking water and adequate sanitation; disease vector breeding places; sexual customs and tolerance; racism; attitudes to disability; trust; land use; urban design; sites of cultural and spiritual significance; local transport options available; etc.
Institutional factors: the capacity, capabilities, and jurisdiction of public sector services	Availability of services, including health, transport and communication networks, educational and employment; environmental and public health legislations; environmental and health monitoring systems; laboratory facilities; etc.

Source: Quigley 2006

In addition, the operating principles for HIA intend to respond to public concern about health, demonstrating health gain as added value and responding to priorities.

11.4.2.4 International Finance Corporation (IFC) of the World Bank Group

The International Finance Corporation (IFC) is a member of the World Bank Group. IFC has 182 member countries (including Canada) and provides investments and advisory services to build the private sector in developing countries. In 2009, IFC has issued a good practice guidance for conducting HIAs, the *Introduction to Health Impact Assessment*.

Although this guide is intended for developing countries, most advice concerning best practices also applies to any large complex industrial projects in developed countries, such as the oil sands in Alberta. According to IFC, HIA is a critical tool for developing evidence-based recommendations for project decision makers and key stakeholders. The main functions of HIA are to identify the most critical environmental and social determinants of health that may be affected by the project, to address health issues that may influence overall sustainability objectives, and most importantly to enhance the project's "*license to operate*" in the eyes of local communities.

This document emphasizes that health impacts may cause project delays, damage to relationships with communities, legal liabilities, and additional costs. However, when properly managed, "*community*

health impact assessments may reduce unnecessary cost (down time, indemnifications), and help create positive perceptions, such as a social license to operate."

11.4.2.5 International Petroleum Industry Environmental Conservation Association (IPIECA)

Another guide on health impact assessment was developed by the International Petroleum Industry Environmental Conservation Association (IPIECA) in 2005. This association was created in 1974 following the establishment of the United Nations Environment Programme (UNEP). IPIECA is the single global association representing both the upstream and downstream oil and gas industry on key global environmental and social issues, and provides one of the industry's principal channels of communication with the United Nations. Company members are numerous and include oil sands developers such as Shell and Total. Organization members include the Canadian Petroleum Products Institute.

IPIECA and the International Association of Oil and Gas Producers (OGP) have combined to address health issues. The OGP-IPIECA health committee (OIHC) aims to identify, prioritize, and develop evidence-based guidance and recommendations on relevant public health issues. In the guide, health impact assessment is characterized as impacts on health status, with the definition of health encompassing the state of complete physical, mental, and social well-being (IPIECA and OGP 2005). It is clearly stated that health is determined by a multiplicity of factors including socioeconomic and environmental factors. For many large and complex oil and gas projects, a project level HIA framework is needed, defining broad health areas of concern (HAOC) that consider both social and biomedical determinants of health. A potential set of critical HAOC is shown in Table 11.3.

The use of the HAOC approach more clearly integrates certain key aspects of the HIA into a framework that is commonly used by both the environmental and social assessment process. This overall integration is important so that the HIA is viewed as an integral and essential part of the overall impact assessment process.

Table 11.3 Health areas of concern (HAOC)

Respiratory infections • Including but not exclusive to: acute respiratory infections (ARIs- bacterial and viral); pneumonias; tuberculosis (TB)
Vector-related disease • Including but not exclusive to: malaria; typhus; dengue
Sexually transmitted infections • Including but not exclusive to: HIV/AIDS; genital ulcer disease; syphilis, gonorrhoea, chlamydia, hepatitis B
Soil and water- borne disease • Including but not exclusive to: soil transmitted helmiths (STH);leptospirosis; schistomiasis; meliodosis; cholera
Food and nutrition-related issues • Including but not exclusive to: stunting; wasting; micro-nutrient deficiencies; changes in agricultural practices; gastroenteritis (bacterial and viral); food safety
Accidents and injuries • Including but not exclusive to: traffic and road related incidents; construction (home and project-related); and drowning
Exposure to potentially hazardous materials • Including but not exclusive to: pesticides; inorganic and organic fertilizers; road dusts; air pollution (indoor and outdoor related to vehicles, cooking, heating, and other form of combustion/incineration ash); any other project-related solvents, paints, oils or cleaning agents, etc.
Psychosocial • Including but not exclusive to: relocation; violence; security concerns; substance abuse (drugs, alcohol, smoking); depression; communal social cohesion
Cultural health practices • Including but not exclusive to the role of traditional medical providers, indigenous medicines, and unique cultural or ethnic health practices
Health systems infrastructure and capacity • Including but not exclusive to: physical infrastructure, staffing levels, and technical capabilities of health care facilities at local, district, and provincial levels • Including but not exclusive to: coordination and alignment of a project with existing national and provincial level health programmes, for example malaria, TB, HIV/AIDS

Source: IPIECA and OGP (2005)

11.4.2.6 International Council on Mining and Metals

The International Council on Mining and Metals (ICMM), of which the Mining Association of Canada is a member, has produced a Good Practice Guidance on Health Impact Assessment. Many companies working in the petroleum industry, such as oil sands developers: Shell Canada, Suncor Energy and

Syncrude Canada, are members of the Mining Association of Canada. The Good Practice Guidance recognizes the importance of integrating health impact assessments with environmental and social impact assessments. The aim of this guide is to provide advice to assist companies in protecting the health and wellbeing of the workforce and local communities (ICMM 2010). This guide represents best practices for companies operating in the mining sector. In the guide, HIAs are considered not only as a way of managing community well-being impacts but also as a way of improving financial performance. The ensuing financial benefits include: speedier achievement of a project's licence to operate, lower risk of future community-led liability and litigation, and lower planning and associated legal and consultancy costs. This guidance also adopts the WHO definition of health as complete physical, social, mental, and spiritual well-being and not only the absence of disease. According to the guide, it is within this wider context that the community health impacts should be considered. The concept of risks and hazards used in EIAs are often not broad enough to encompass all the determinants of health that can be changed by a project. Also, the term *risk* typically focuses on negative influences which do not highlight opportunities for improving community health and well-being (ICMM 2010).

According to ICMM, there are three different but overlapping health assessments that a mining project may need to undertake: health risk assessment (HRA), health impact assessment (HIA) and health needs assessment (HNA).

- Health Risk Assessment: To predict risk of the potential direct physical health impacts from chemicals emitted into air, water and soil.
- Health Impact Assessment: To predict and manage changes in the wider determinants of health and in health outcomes attributable to a project or a plan.
- Health Need Assessment: To understand the existing health needs of a community.

All three assessments can be combined to conduct strategic health planning in relation to the potential health and wellbeing impacts of projects.

11.4.3 Significance of Impacts According to Best Practice Guidelines

In order to assess objectively the importance of each impact, they were individually evaluated against set criteria proposed by industry, taken from the Good Practice Guidance on Health Impact Assessment (ICMM 2010). When analyzing health impacts, it is important to consider the magnitude and the likelihood of the impact occurring. In the end, the goal is to assess the public health significance of the potential impacts based on these two main criteria as shown in Table 11.5.

Table 11.4 Rating used to rate significance of impacts

Magnitude of impact		**Likelihood of Occurrence of a Health Impact**		
		Low	**Medium**	**High**
Health impact rating	**Description**	Unlikely to occur	Likely to occur sometimes	Likely to occur often
0	None	No significance	No significance	No significance
1	Low	Very low significance	Low significance	Medium significance
2	Medium	Low significance	Medium significance	High significance
3	High	Medium significance	High significance	High significance

Source: ICMM 2010

Table 11.5 Integrated significance scale for the levels of potential impact

	Magnitude/consequences of impacts	**Likelyhood/ probability of impacts**	**Significance of Impact (Magnitude x Likelihood)**
	None *Low* *Medium* *High*	*Low* *Medium* *High*	*No significance* *Very Low* *Low* *Medium* *High*
(1) Effects caused by environmental changes and exposure conditions	Low negative impacts	Low	Very low
(2) Effects caused by environmental changes and exposure conditions related to accidents and disasters	High negative impacts	Low	Medium
(3) Effects on community health and effects on the wider determinants of health and well-being	High negative impacts Simultaneous with High positive impacts	High High	High High

Source: ICMM 2010

As shown in Table 11.5:

(1) Effects caused by environmental changes and exposure conditions are qualified as being low since exposures tend to be low intensity over a small area affecting a limited number of people. These would include, for example, specific health consequences from an upper bound individual exposure to a specific toxic substance(s). Environmental contaminant exposures still remain important local concerns; therefore, it is important to address them with care. Also, mitigation measures could reduce detected negative impacts, bearing in mind that the cumulative effect of a set of minor exposures might cause important effects. These concerns justify maintaining responsive health surveillance to detect and respond to any potential cumulative impacts.

(2) Such effects can become more important in the case of technological disasters complicated (or not) by extreme meteorological events.

(3)(a) Effects on community health and effects on the wider determinants of health and well-being are considered as being highly negative effects because they affect both physical and mental health directly or indirectly and in some cases may be permanent in nature. They can be high intensity, long-duration effects, occurring over a wide geographical area and affecting a large number of people (over 500 people).

(3)(b) However, some effects can also be beneficial, mainly through increased employment and income, and in that case, they are also considered highly positive effects as they can enhance well-being significantly and reduce exacerbations of existing illnesses as well as the occurrence of acute or chronic diseases.

11.4.4 Cumulative Impact Assessment

11.4.4.1 Cumulative Effects

Cumulative effects are generally defined as the combined effects of more than one action or project, with specific focus on the spatial and temporal incremental impact of the action or project when added to other past, present, and reasonably foreseeable future actions and projects. AENV defines cumulative effects as "*the changes to the environment caused by an activity in combination with other past, present, and reasonably foreseeable human activities*" (ERCB/NRCB/AENV 2010).

The typical project and site specific approach to environmental assessment has limitations to assessing potential cumulative effects. The impact of an individual project on an environmental resource (biophysical, economic, health, etc.) may be considered insignificant when assessed in isolation, but may be significant when evaluated in the context of the combined effect of all past, present, and reasonably foreseeable future activities that may have or have had an impact on the resources in question.

Unlike direct and indirect impacts which can be generally readily associated with a particular project, cumulative impacts may have less defined spatial and temporal manifestations. They may be additive or more than additive (synergistic) and are often classified accordingly. Cumulative effects may be linear, where each incremental addition and/or deletion has the same effect, or they may be amplifying

or exponential where each addition and/or deletion has a larger effect than the previous one. Terms such as *discontinuous*, *impact saturation*, and *potentiation effects* are used to describe scenarios in which incremental additions and/or deletions have no apparent consequences until a threshold is crossed. In many cases, that threshold is not known. The least understood, and therefore most feared, cumulative effect type is termed "structural surprises" wherein effects occur suddenly and locally, mostly from multiple developments.

Assessment of cumulative effects is not an exact science and is fraught with uncertainty. Cumulative effects are best analyzed from the perspective of the specific resource, ecosystem, and human community being affected as they rarely correspond to individual project boundaries. By evaluating resource impact zones and the life cycle of effects, rather than individual projects, the boundaries of cumulative impact assessment can be better defined. Determining cumulative environmental effects of a project requires delineating cause-effect relationships between multiple actions and the environment of concern. In most cases, it will be beyond the scope of an individual environmental assessment to include a full-fledged cumulative impact assessment. However, an assessment of the potential for cumulative effects is critical. The criteria for judging the significance of cumulative effects are similar to other types of environmental assessment, with threshold effects and irreversible changes of particular concern.

11.4.4.2 Cumulative Effects Assessment in Alberta

The historical lack of cumulative impact assessment in oil sands development has been a concern for many. For example, Vlavianos (2007) notes: "*Numerous commentators have highlighted the problems inherent with an approval process that reviews projects on an individual basis. Dealing with each project in isolation precludes a proper assessment of cumulative effects of both the particular project in question, but also of the effects of that project in conjunction with other industrial projects in the area.*"

The Cumulative Environmental Management Association (CEMA) was originally created in 2000 to address a number of issues identified in the 1999 Regional Sustainable Development Strategy for the Athabasca Oil Sands Area, in part, to deal with monitoring the cumulative effects of multiple developments. The original mandate of CEMA was to study the cumulative environmental effects of industrial development in the region and produce guidelines and management frameworks. A major Government of Alberta review of needs for dealing with the rapid growth of oil sands development (Gov AB 2006) recommended:

> *The provincial government should initiate an independent evaluation of the operations of the Cumulative Effects Management Association with a view to enhancing its efficiency and timeliness in developing recommendations. The review should address governance issues, types of decisions which need not be the subject of consensus, the adequacy of the regulatory backstop, and the resources required for CEMA to be more effective.*

A number of First Nations and NGOs withdrew from CEMA membership in 2008 apparently because they were frustrated by the management structure and their limited ability to influence CEMA decisions. This seriously damaged the credibility of CEMA as a multi-stakeholder group, not to

mention its effectiveness in addressing cumulative effects in a meaningful way. As a result, CEMA was subjected to two independent, third-party reviews by Price Waterhouse Coopers and by Integrated Environments and Tumbleweed Consulting, leading to a revitalization strategy. Combined with the Government of Alberta's newly announced approach to cumulative effects management under the new Alberta Land Use Framework and a commitment to the development of a Lower Athabasca Regional Plan, CEMA was restructured. In 2009, a Joint Governance Review Team was created to explore options for change. The Joint CEMA Governance Review Team identified a number of strategic challenges, options, and recommendations in the following areas:

1. Geographic Area, Vision, Mission, and Goals for CEMA
2. Organizational Structure
3. CEMA-Government Relationship
4. Member Issue Identification
5. Issue Prioritization
6. Aboriginal Engagement
7. Non-Governmental Organization (NGO) Engagement
8. Regional Committee Interface/Relationships with Other Regional Organizations
9. Long-Term Funding
10. Performance Tracking and Indicators

In May 2010, the new structure and operational mode of the CEMA was approved by its Members at the Annual General Meeting. The key change to CEMA is the adoption of a sector-based Management Board. CEMA will now have four caucuses: Aboriginal, Industry, Government, and Non-Governmental Organizations. Each of these caucuses will have four members, guaranteeing equality in the decision-making process. The newly structured board is designed to ensure the Aboriginal and Environmental Non-profit Groups a fair and equal voting process. Salvaging a credible CEMA was a vitally important initiative for all who have a stake in managing environmental impacts from oil sands development.

CEMA is clearly a critical player in managing cumulative impacts from the oil sands. As of July 2010, CEMA is a multi-stakeholder organization governed by more than 40 members representing all levels of government, industry, regulatory agencies (including Saskatchewan Environment), NGO environmental groups, and Aboriginal Groups (see Appendix A7). CEMA now has seven working groups: Sustainable Ecosystems, Reclamation, NO_x/SO_2 Management, Surface Water, Trace Metals and Air Contaminants, Traditional Environmental Knowledge, and Groundwater.

CEMA is concerned that there are still large gaps remaining in many critical areas of environmental management, including the lack of a land use plan for protecting wildlife and regional ecosystems, no

lower lower limits on flows of the Athabasca River below which oil sands water withdrawals would be prohibited, the lack of a environmental management plan to maintain the integrity of watersheds, and no common standards for oil sands reclamation. CEMA recently concluded that the wide range of competing commercial interests, particularly individual oil sands companies, have been difficult to overcome in the quest for regional management versus licensing of individual projects (Severson-Baker et al. 2008). CEMA has failed to achieve a regional environmental management system, and resource developers and regulators have failed to apply cumulative effects based environmental management practices.

Cumulative effects management is becoming more formalized in Alberta. The Government of Alberta states that cumulative effects management will be outcome-based with clearly defined desired end-states, place-based to meet the differing needs of regions within the province, performance management-based using adaptive approaches to ensure results are measured and achieved, collaboratively built on a culture of shared stewardship using a shared knowledge base and comprehensively implemented using both regulatory and non-regulatory approaches. The Government of Alberta indicates that the transition to a cumulative effects management approach is continuing to evolve and that "*the shift will require integration and discussion with and between government ministries, other governments, industry sectors, municipalities, non-government organizations and all Albertans*" (Gov AB 2010).

In 2007, the Government of Alberta developed a cumulative effects policy paper and announced site specific pilot projects. In 2008, it released the Land Use Framework, followed by the Alberta Land Stewardship Act in 2009, to provide a legislative basis for implementation. These initiatives divide the province into seven regions and commit the province to taking a cumulative effects approach to environmental management.

The 2009 Responsible Actions Progress Report notes that "*A review of the current Environmental Assessment process has begun. It will reflect the new focus on cumulative effects management on a regional scale and improve overall efficiency and effectiveness of project environmental impact assessments*." (Gov AB 2009b). AENV is reviewing the environmental assessment process within the context of cumulative effects management, focusing specifically on improving effectiveness and efficiency that could be gained through regional planning efforts. This work is led by AENV and involves the CCME task group which evaluated the utility of the Regional Strategic Environmental Assessment as a possible approach to improving cumulative effects management. This work culminated in a 2009 document, the Regional Strategic Environmental Assessment in Canada: Principles and Guidance.

Recently, AENV has required EIA reports to consider both the specific individual and cumulative impacts of a project. Currently, the Government of Alberta is reviewing the existing regulatory system for upstream oil and gas to achieve efficiencies and improvements, including optimization options for delivery of the current in situ integrated EIA and approvals process. Known as the Regulatory Alignment Project, this is a multi-ministry project led by the Alberta Treasury Board and it is expected to be completed in October 2010.

Numerous commentaries have addressed the approach of cumulative effects assessment in Alberta. McEachern (2008) discusses a disturbing trend towards "*intellectual laziness in the regulatory world*" and describes the recent evolution from sector-based environmental management to cumulative effects management in Alberta under the new policy direction of the Alberta Land Use Framework. Two opposing approaches currently pursued in Alberta to establish the metrics of cumulative effects management are outlined and a case is made for reliance on ecologically defined criteria over the potentially dangerous approach of setting socially desired outcomes first. Sherrington (2005) discussed biodiversity assessment and social process in the oil sands region with an emphasis on structure, function and biodiversity indicators. Squires et al. (2009) illustrated a tangible attempt at cumulative effects assessment in looking at changes in the water quantity and quality in the entire Athtabasca River mainstream comparing data from 1966–1976 with data from 1996–2006.

The recent progress and announced plans of the Government of Alberta regarding cumulative effects assessment and management are generally promising; however, clear and sustained action is required to address the cumulative impact issues in the Alberta oil sands region. Cumulative effects determination and management have been repeatedly raised as a concern at hearings addressing individual project EIAs and have been acknowledged as a priority need for regulatory reform by the Government of Alberta. The EUB (now ERCB) noted in its 2006 *Year in Review* that the Board had held hearings on four major oil sands applications: Suncor's Voyageur Upgrader and its North Steepbank Mine, the Shell Albian Sands Muskeg River Mine expansion and the Imperial Oil Kearl Mine Project. Based on what the EUB heard, it "*asked the governments of Alberta and Canada to give priority to the challenges related to cumulative environmental impacts*" (EUB 2007). As an aside, this is an interesting statement coming from the EUB given its primary role in making the public interest decision on these projects, including full consideration of their project EIAs.

A major concern related to cumulative EIA has been the lack of availability of environmental data for current operations in the oil sands region. Certainly a comprehensive assessment of these data, in a timely manner has not occurred in spite of the fact that regular monitoring is required on all operations under their EPEA approvals. There appears to be no requirement for regular assessment of these data, only their continued collection and submission. Providing wider access to these data is an obvious priority for improving cumulative impact assessment.

11.4.4.3 Management of Cumulative Health Effects

Key players have recognized the limitations of a project-by-project approach to assess the environmental effects of oil sands projects. Since 2000, the Cumulative Environmental Management Association (CEMA) was created to address this issue. However, it has been criticized as being unable to provide tangible results for the management of cumulative impacts (Kennet 2007). Furthermore, none of its working groups focus specifically on health impacts, according to the full definition of health. CEMA focuses on issues that can be broken into impacts of industrial activity on the land, water and air: it does not include socio-economic issues that could be affecting the health and well-being of oil sands communities.

A second initiative was the Government of Alberta's Regional Sustainable Development Strategy (RSDS) for the Athabasca Oil Sands Area, released in 1999 (AENV 1999). Stakeholders involved shared responsibility for several areas, including protecting human health. At the very beginning of the strategy they clearly state the vision of sustainable development for Alberta: "*Alberta, a member of the global community, is a leader in sustainable development, ensuring a healthy environment, a healthy economy, and a high quality of life in the present and future. – Alberta's Commitment to Sustainable Resource and Environmental Management*."

RSDS mentions that "*AENV recognizes the importance of the numerous multi-stakeholder activities dealing with a wide variety of sustainable resource, environmental and health issues related to the development of the Athabasca Oil Sands*." It also highlights the issue of health being common to most themes, and the condition of the environment as being important to the health of regional residents. According to the strategy, Alberta Health and Wellness was to be involved directly or be consulted on the health-related aspects of each theme area. However, in the strategy, human health impacts are only considered as they relate to the state of the environment. For example, a central theme of the strategy is the effects of air emissions on human health. A sustainable development strategy aiming at high quality of life and protecting human health does not consider a broader assessment of health impacts using health determinants is peculiar. Oddly, socio-economic issues are also missing from the sustainable development strategy. RSDS only states that AENV anticipates that planning activities for orderly economic development will be led by the ERCB, the industry, and municipal, provincial and federal agencies with related responsibilities. RSDS also anticipates that activities related to monitoring, planning, and delivering public health services will be led by regional and provincial health agencies, with participation by federal health agencies where appropriate.

RSDS is being implemented in partnership with the CEMA. On the whole, the RSDS was a worthwhile initiative that aimed at providing a framework for balancing development with environmental protection and providing a common ground for government and stakeholders to work together to set new, specific regional resource goals. However, its narrow definition of health and its focus on physical environmental impacts renders it unsuccessful in its attempt to manage community health and well-being.

11.5 Governance

Responsible Actions – A Plan for Alberta's Oil Sands 2009 was published in 2009 after province-wide consultations. This is a high level, public relations-oriented document which specifies six strategies:

1. Develop Alberta's oil sands in an environmentally responsible way

2. Promote healthy communities and a quality of life that attracts and retains individuals, families, and businesses

3. Maximize long-term value for all Albertans through economic growth, stability, and resource optimization

4. Strengthen our proactive approach to Aboriginal consultation with a view to reconciling interests

5. Maximize research and innovation to support sustainable development and unlock the potential of Alberta's oil sands

6. Increase available information, develop measurement systems, and enhance accountability in the management of the oil sands

Each strategy includes a number of relevant specific elements, many[39] of which, if implemented, would provide tangible guidance to the ERCB and Alberta Environment if they were faithfully and rigorously implemented. The stated intentions to deal with cumulative impact assessment need to progress into tangible and effective actions.

From a public health perspective, there are essential public health services that must be rendered under good governance. In the case of the oil sands, public health governance has failed to implement a community health improvement process and clear strategic planning for oil sands development. The Alberta Government, in a report concerning the future of health care in Alberta, promotes health impact assessment but no evidence of implementation could be found in our review (Gov AB 2008).

In Alberta, public health programs are mandated to address the social, economic, and environmental factors that affect health. In oil sands development, environmental impact assessment has only focused on environmental factors affecting health. As a consequence, only health risk assessments are conducted as part of EIA of major oil sands projects. There are limited socio-economic issues considered in these assessments. There have been no comprehensive HIA guidelines and EIA has failed to abide by the definition of health adopted by the Alberta Health and Wellness.

In short, if such projects were to occur in some other parts of Canada or in developing countries, it is likely that HIA would be conducted as they are routinely requested by other governments or the World Bank, in the case of developing countries, for instance.

11.6 Summary Issues of Concern

This section deals with a range of economic and policy issues recognizing that economic factors are major drivers in decision-making. The concept of environmental and health impacts being negative externalities in the economic evaluation is explained and the economic implications for Canadians are described. With water use being a major consideration from an environmental perspective, the reality is that water used by industry in Alberta (and throughout much of Canada) is currently subject only to minor administrative fees, eliminating any economic incentive for minimizing water use.

Financial security for reclamation obligations is a large issue regarding potential future liability for Albertans and a careful review of current practices aligns with repeated comments from the Auditor General of Alberta, that substantial improvements are needed to the current financial security arrangements to minimize the potential liability to the public purse.

[39] For example: 1. Require industry to use best available technology economically achievable (BATEA) – where BATEA refers to technology that can achieve superior performance and has been demonstrated to be economically feasible through successful commercial application across a range of regions; 2. Require reclamation of tailings to occur at the same rate as (or faster than) the production of new tailings on a regional basis where reclamation means the process of converting disturbed land to a state where it is capable of supporting the same kinds of land uses as before the disturbance.

Current practices in environmental impact assessment (EIA) were reviewed with regard to their coverage of socio-economic impact assessment with a finding that relevant topics are addressed by EIAs, but there is little evidence of rigorous analysis of socio-economic impacts compared with requirements for international development projects. A more broadly defined cumulative impact assessment has been widely recognized as essential for the kind of massive development occurring in the oil sands, but while there are some encouraging developments, there is only limited evidence of tangible progress towards implementing these assessment tools

Major gaps have been identified in the current process of assessment, prevention and mitigation of health impacts of oil sands exploitation, as well as major negative and moderate positive indirect health impacts linked to the past exploitation of oil sands. Specifically, the current EIA process for oil sands developments only addresses health through a contaminant-specific risk assessment approach. Other impacts related to broader health determinants are only considered indirectly through the limited socioeconomic impact assessments (Section 11.4.1.1) that are currently performed.

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PART 3 WHAT DOES IT ALL MEAN?

Section 12 includes a summary of panel findings on major issues; panel findings in relation to 12 questions which capture some of the current public debate over environmental and health issues concerning oil sands development, and general panel observations. The panel operated on the premise that the economic and strategic importance of the oil sands industry to Alberta and Canada is self-evident, so this report only summarizes the magnitude of some of these economic factors based on available credible evidence. The impact of the oil sands industry to the foregoing jurisdictions in the short-term can be adequately demonstrated by fully answering the rhetorical question: *What would the consequences be for Alberta and Canada if the oil sands industry was to shut down in the next year or the next five years?* No further consideration of this rhetorical question is given here.

The panel findings on some major environmental and health impact issues are as follows.

- Current Government of Alberta policy on financial security for reclamation liability leaves Albertans vulnerable for major financial risks which are exacerbated by the current rate of reclamation which is not keeping pace with the rate of land disturbance. Major improvements in tailings management have been made in the past decade and reclamation of uplands landscapes is clearly feasible based on extensive research despite the small scale of certified reclamation to date. Reclamation of wetlands landscapes is less certain and the feasibility of the EPL option for reclamation of tailings-filled mined out areas remains to be demonstrated despite having been approved-in-principle in 1993.

- There is currently no credible evidence of environmental contaminant exposures from oil sands developments reaching downstream communities at levels expected to cause elevated human cancer cases in the local population. Highly publicized media reports of downstream contamination from oil sands developments are likely amplifying the considerable concern among downstream residents about their health, particularly given the magnitude and visual impact of industrial development that is occurring. Current levels of concern in potentially affected communities make it important for previous environmental contaminant exposure studies, which have focused on air pollutant exposures, to be expanded. New exposure assessment studies need to address contaminant exposures in food and water. The prospects are not promising for reaching definitive answers about health impacts from contaminant exposures using only conventional epidemiological methods on such small populations. This reality makes documentation of contaminant exposures by rigorous and thorough exposure assessment which can be compared with other relevant populations not located in oil sands regions the best approach for addressing these ongoing concerns.

- There is population level evidence that residents of the Regional Municipality of Wood Buffalo (RMWB) experience a range of health indicators that are poorer than the provincial average, which is dominated by the urban populations of Calgary and Edmonton, and are also poorer than indicators for a more relevant comparison with residents of what was formerly Peace Country Health Region. These indicators are consistent with the “boom town” effect and likely reflect the consequences of strained health and social infrastructure in RMWB as a

consequence of the rapid pace of oil sands development. The Government of Alberta has recognized some of the infrastructure funding shortfalls caused by the rapid growth and major additional funding has been directed to the region, but we could find no evidence of any specific public health interventions to address some of the serious population health issues. At least, some investigation to validate these health discrepancies is needed, with subsequent strategies developed based on validated need.

- The Environmental Impact Assessment (EIA) process that is relied upon by decision-makers (i.e., panels for the Alberta's Energy Resources Conservation Board, ERCB and in some cases the Canadian Environmental Assessment Agency, CEAA) to make a determination whether proposed projects are in the public interest is seriously deficient in formal health impact assessment (HIA) and quantitative socio-economic impact assessment (SEIA) as would be required for World Bank projects, for example. Currently, human health impacts are assessed only by quantitative health risk assessment that is focused on predicting environmental contaminant exposures while population health impacts as outlined in the third bullet above, human health risk from technological disasters and occupational health are not addressed. Socio-economic impacts of developments are addressed only in a general, qualitative manner and these assessments would not satisfy the requirements of the World Bank for funding international development projects. Despite long-standing commitments to cumulative impacts assessment there is little tangible progress evident in recent EIAs or current regulatory policy.

- Considerable progress has been made by the oil sands industry in reducing its greenhouse gas (GHG) emissions intensity (amount emitted per unit of production) over the past two decades. The Government of Alberta has implemented the first regulatory requirements in Canada to achieve reduced GHG emissions from all major Alberta GHG emitters, but these reductions in emissions intensity will not be sufficient to cause overall reductions in GHG emissions from the oil sands industry because of recent and projected growth in bitumen and synthetic crude oil (SCO) production. The oil sands are not Alberta's largest industrial source of direct GHG emissions, but they currently represent about 5% of Canada's total GHG emissions. Thus, the continued growth of oil sands direct GHG emissions will create a major challenge for Alberta and Canada to meet Canada's international commitments for reducing overall GHG emissions.

- Despite over 30 years of water quality monitoring in the oil sands region, assessment of water quality impacts on regional tributaries and the Athabasca River has been controversial. This is partly because of recently published studies which, albeit based on sparse data and showing very little measureable impact on water quality for industrial developments of this scale, do support a hypothesis of measureable impact arising from oil sands developments on river water concentrations of polycyclic aromatic compounds (PAC), including polycyclic aromatic hydrocarbons (PAH) and various trace metals. This water quality impact hypothesis has been represented as demonstrating inadequacy of the RAMP, an industry-funded program created in 1997 partly based on recommendations arising from Environment Canada river studies over several years in the oil sands region. The adequacy of RAMP has been, or is currently, the subject of three reviews, commissioned respectively by RAMP as its routine five year review,

the federal Environment Minister, and the provincial Environment Minister. The timing of these reviews concurrent with our review has not allowed us to consider their findings. However, based on our review we concluded RAMP does need:

- Ongoing external scientific oversight at a greater frequency than every five years, to demonstrate that it is using the best available monitoring methods with state-of-the-art detection levels.
- Assurance that its biological monitoring programs are at least equivalent to those used by the Environmental Effects Monitoring program for the pulp and paper industry.
- Data made publicly accessible similar to the public access provided to air quality data by the Wood Buffalo Environmental Association (WBEA).

The Government of Alberta needs to make the water quality monitoring reported under individual industrial approvals issued under the Environmental Protection and Enhancement Act (EPEA) publicly accessible, particularly for monitoring that EPEA approvals require to be reported for tailings pond dyke seepage and groundwater. Other related concerns are the current absence of a regional groundwater model and the implications for groundwater of any major difficulty encountered reclaiming wetlands are.

- The current ambient air quality monitoring data for the region show minimal air quality impacts from oil sands development on regional air quality except for serious odour emission problems over the past two years. These problems may have been associated with reclamation of the first oil sands tailings pond at Tar Island which was announced as completed in September 2010. Nonetheless, Alberta Environment (AENV) must demonstrate in a publicly credible manner that it is implementing its own stated policy of requiring best available technology economically achievable (BATEA) for emissions control, particularly when applicable BATEA is being demonstrated for similar industrial emissions such as the power generation industry. Ongoing controversies over water quality impacts of oil sands developments indicate a need to validate reporting of contaminant emissions to the National Pollutant Release Inventory (NPRI), including validated monitoring of fugitive emissions from surface mines and tailings ponds.

- A Government of Alberta report in 2006 called for major expansion of the regulatory capacity of AENV and Alberta Sustainable Resource Development (SRD) to cope with the growth of the oil sands industry. Notwithstanding announced increases in regulatory inspection capacity of the ERCB for dealing with oil sands operations, the necessary increase in regulatory capacity for the other two agencies is not evident, particularly in light of possible regulatory factors which may have contributed to more than 1600 ducks being killed by oiling on a tailings pond in April 2008. These agencies need to seriously review whether they have and can effectively maintain the specialized technical expertise needed to regulate industrial development of this scope and sophistication, particularly in a preventive manner that demands detailed industry-specific technical knowledge by its regulatory personnel. EPEA provides that designated

directors will make regulatory approval decisions independent of influence from senior management or politicians. The people of Alberta must be able to have confidence that such regulatory decisions are being made by highly skilled, senior technical specialists based strictly on the merits of scientific, technical, and economic evidence free of political interference. There is an adequate mechanism under Alberta legislation for the Minister to make the final decision about regulatory approvals and related decisions if these are appealed.

Our governments—federal and provincial—need to show some leadership in not only clearly demonstrating responsibility in how the oil sands are currently developed now and in the future, but also in beginning to look ahead to a time when an economy based on fossil fuels may no longer be viable.

The Public Debate

The panel sought to frame this assessment of the oil sands development in the context of issues and questions that are on the minds of Canadians. These questions have been distilled from a variety of recent documents produced by non-governmental organizations (NGOs), government, and industry advocating positions both for and against the merits of the oil sands industry. The following questions are provided together with what the panel has found based on our review of the evidence.

1. ***Can technology solve all of the environmental challenges of oil sands development?***

   - Technology cannot reduce the environmental impacts/footprint to zero in the oil sands industry any more than it can in any other heavy industry (e.g., mining, smelting, forestry, power generation).

   - There have been substantial improvements in the environmental performance of oil sands production including substantially reduced intensity (i.e., per unit of production) of GHG emissions (down by 39% since 1990 according to Environment Canada, Env Can 2010a) and water use for both surface mining and in situ technologies. These include: slurry hydrotransport allowing substantial reductions in extraction temperature for surface mining bitumen extraction with consequent reductions in GHG emissions; recycling warm water from the tailings stream to extraction, reducing energy needs for heating otherwise cold water; paraffinic froth cleaning for bitumen extraction, reducing GHG emissions by reducing the need for energy intensive centrifugation, and widening the upgrading technology portfolio by inherent partial upgrading of bitumen; improved bitumen recovery by novel chemical additives, reducing energy intensity of production because less material is moved and processed; and use of shovels and trucks for mining contributing to a significant reduction in GHG emissions by eliminating old energy intensive conveyor belts for oil sands transportation after mining by bucket-wheels and draglines, and by providing flexibility of mining for optimal processing. These reductions in emission intensities achieved by improved operating and process technologies have been more than off-set by the rapidly growing rate of bitumen production and upgrading.

- Important technologies are under development which hold promise for continued improvement in overall environmental performance for reducing land disturbance, facilitating rapid land reclamation, and reducing emissions. Advances include: integrated technologies based on gasification of coke and asphaltenes, solvent-based in situ production to reduce GHG emissions by reducing or eliminating the need for steam and minimizing energy intensity of mobilizing bitumen by solvent injection and/or electro-thermal in situ recovery integrated with carbon capture and storage; CO_2-enhanced oil recovery (EOR) to reduce GHG emissions, partial catalytic in situ upgrading through in situ combustion to provide energy to mobilize bitumen and development of practical coagulants to consolidate tailings more rapidly and release pore water. For some new technologies there may be trade-offs such as reduced water use or land disruption vs. increased GHG emissions, and these trade-offs must be recognized.

- A number of important and substantial technological challenges remain.

    - Tailings reclamation including proposed end pit lakes (EPLs) remains a major question because no tailings pond has yet been completely reclaimed.

    - The first oil sands tailings pond adjacent to the Athabasca River had its mature fine tailings (MFT) removed, with surface reclamation in September 2010 but the removed MFT must continue to be processed at other locations.

    - GHG emissions per m^3 of bitumen are highest for in situ oil sands production and as long as these methods are based on generating steam by burning fossil fuels, this is likely to continue.

    - Carbon capture and storage (CCS) is appealing from the perspective of GHG policy as a whole but does not appear to be very feasible for oil sands production in general and in-situ in particular. Bitumen upgrading could provide a more promising source of applications for CCS. Substantial questions remain to be answered about the feasibility and reliability of CCS in all applications.

2. ***Is in situ bitumen recovery more environmentally benign than surface mining technology, recognizing that in situ will be the major source of bitumen production in the future?***

- The nature of surface disturbance associated with in situ bitumen recovery is clearly different from surface mining. In situ operations involve clearing a smaller area (per m^3 of bitumen production) including extensive linear developments, which if supporting developments like natural gas supply are accounted for, may be similar to surface mining in total quantity, but does not involve dewatering, overburden removal, tailings storage, and associated reclamation challenges faced by surface mining. The nature of reclamation for disturbances caused by in situ bitumen recovery poses no particular technological challenge; the types of reclamation activities needed for in situ production have been

practiced successfully for many years in other applications (e.g., conventional oil production).

- Net water usage by in situ bitumen recovery is substantially lower than required by surface mining. In situ water use has involved a greater proportion of groundwater and extensive use of saline groundwater has been demonstrated.

- GHG emissions per m^3 of bitumen produced are higher (10% to more than 20% on a well-to-wheels life cycle comparison) for in situ technologies currently in use compared with surface mining.

- Emissions of all air pollutants except for carbon monoxide (CO) are substantially lower for in situ bitumen recovery compared with surface mining bitumen recovery.

- There are uncertainties, which need better characterization, around potential groundwater contamination by in situ operations.

- Environmental impacts are different, and in some cases substantially less than surface mining, but in situ technologies are not free of environmental impacts.

3. ***Does oil sands water use and pollution threaten the viability of the Athabasca River system and downstream waters?***

- Water use at current levels does not threaten viability of the Athabasca River system if the Water Management Framework developed by AENV with the federal Department of Fisheries and Oceans (DFO) to protect in-stream, ecosystem flow needs is fully implemented and enforced. Authority under the province's Water Act (WA) for water withdrawal licences issued to oil sands operators is adequate to achieve the protection required.

- Fresh surface water use is mainly associated with surface mining operations and although water demand is substantial, it is not an unsustainable fraction of available water flow in the Athabasca River. Water use for operating projects in 2008 was <0.7% of total annual flow that year and <0.5% of longer-term mean annual flow. Cumulative maximum allowable use is restricted to <10% of the lowest 5th percentile weekly flow by the Athabasca River Water Management Framework. Water actually used was about 23% of the maximum water allocated to the oil sands industry, an allocation which was <5% of total water allocations in Alberta, compared to 43% of Alberta's total water allocations for irrigation, for example.

- Concerns expressed about water withdrawals during low flow conditions in the Athabasca River (typically in winter) can be addressed effectively by implementing additional industrial off-stream water storage to capture water during seasonal high flow in spring. Substantial reductions in Athabasca River flow resulting from climate change would drive implementation of this option to a greater degree.

- Current evidence on water quality impacts on the Athabasca River system suggests oil sands development activities are not a current threat to aquatic ecosystem viability. However, there are valid concerns about the structure of the current RAMP that need to be addressed regarding appropriateness of data collected, public access to RAMP data, independent scientific oversight, and verification of results.

4. ***Does oil sands development threaten regional groundwater resources or pose a threat to transfer process contaminants to surface waters?***

- Potential threats to groundwater are commonly mentioned in individual project environmental impact assessments (EIAs), but these concerns are typically addressed to local groundwater resources, and there needs to be greater attention directed to regional groundwater resources.

- The regional groundwater resource is not well characterized so it is difficult to judge the nature of the groundwater resource that may be at risk. Groundwater flow velocities are much smaller than surface water flow velocities, e.g. groundwater typically moves at a rate of 1 metre per year (m/y) in permeable aquifers compared to water velocities of metres per second (m/s) in the Athabasca River. Therefore, the time scale for groundwater pollution is much longer than it is for surface water, taking decades or more for groundwater pollutants to migrate from a source to a receptor.

- Seepage from tailings dykes is an intentional design feature to assure stability of dykes constructed with permeable sand. That seepage, which contains substantial quantities of dissolved organic carbon, largely NA, must be collected and returned to the inventory of process-affected waters on the operating plant site. Only a few published studies present seepage measurements and track groundwater contamination from tailings ponds. These studies indicate seepage rates highly depend on local geological materials, including those underlying dykes, and transport of NA in groundwater is poorly characterized.

- Successful reclamation of the original Tar Island tailings pond which had its inventory of mature fine tailings removed and replaced by sand completed in 2010 will be an important demonstration of what can be expected for impact on groundwater and surface waters from tailings dyke seepage from a reclaimed tailings pond in the long-term.

- Modifications to groundwater regimes which are feeding regional wetlands, such as dewatering before landscape clearing and mining, have potential to reduce the proportion of wetlands that will occur in a fully reclaimed regional landscape.

- The unresolved challenge of demonstrating long-term reclamation success of wetland landscapes poses a concern for groundwater regimes.

5. ***Will all disturbed land ultimately be restored to a natural state by oil sands developers?***

- Alberta legislation requires that all disturbed lands must be reclaimed to an equivalent land capability. Contrary to popular belief, the legislation and regulations do not require reclamation to boreal forest ecosystems, although this expectation has evolved over time with applications to operate and subsequent approvals.

- Reclaimed conditions will resemble and function as natural landscapes, provided that the legislated requirements are fully implemented, but reclaimed conditions will not be identical to the pre-disturbance state.

- If developers cannot (or will not) undertake the needed reclamation activities, provisions are in place to protect the public from financial liability (see Question 7). In such cases, however, responsibility for insuring the needed reclamation activities are undertaken and funded would rest with the Government of Alberta rather than the developer. Since the associated reclamation costs are likely to exceed the amount of financial security held by the province, such cases would create a financial liability for the Government of Alberta.

- Use of standardized definitions for terms such as equivalent land capability, reclamation, and restoration are critical for establishing end land use goals, expectations, and requirements.

- Functional upland landscapes (soil and vegetation) can be reclaimed with current reclamation strategies, although some potential groundwater issues related to leaching salts require attention. The use of leaf, fibric, humic material (LFH) has substantially enhanced biodiversity in reclaimed uplands.

- The potential for successful reclamation of wetlands, particularly peatland, has not been well demonstrated in the research to date although studies elsewhere indicate more feasibility than generally believed.

- The reclamation of tailings ponds and the EPL approach raise many questions about feasibility because no tailings pond has yet been fully reclaimed (see Questions 1 and 4 above).

6. ***Are traditional Aboriginal land uses adequately recognized in authorizing oil sands development activities?***

- For the duration of surface mining operations and reclamation, which are likely to last for three or more generations (50–100 years), the affected landscapes are not available for traditional Aboriginal use. As of March 2009, 602 km^2 have been disturbed by oil sands mining operations, an area equivalent to a square 24.5 km x 24.5 km or about 90% of the area of the City of Edmonton. The total potentially surface-mineable area of the oil sands deposit is about 4,800 km^2 (about two-thirds of the greater Toronto metropolitan area)

(Greater Toronto 2010) mainly in the Athabasca River valley downstream from Fort McMurray. For comparison, the James Bay Project hydroelectric project flooded at least 9,715 km² of boreal forest in northern Quebec (Berkes 1988).

- If reclamation is successful, which is more certain for uplands than for wetlands, traditional land uses should be possible in the future.
- Judging the magnitude of negative impacts of the landscape area impacted by disturbance is not possible without up-to-date studies on the current traditional activity patterns and current attitudes towards development among potentially affected First Nations and Métis populations.
- Cumulative negative effects through cultural and demographic stress for regional First Nations and Métis populations are likely to be more severe if imposed without consultation, reasonable accommodation, and creative, meaningful engagement in sharing benefits of developments.

7. Is financial security for oil sands disturbed land reclamation adequate?

- Financial security for surface mining oil sands operations is administered by AENV; no financial security is collected for associated processing plants (upgraders and extraction plants) which will require remediation and reclamation.
- For financial security purposes, some mining operations are governed by previous legislation that sets financial amounts according to production, not estimated reclamation liability.
- Evidence in Canada and the U.S. for coal and hard rock mining suggests financial security requirements have been chronically underestimated.
- Financial security requirements for in situ operations are administered by the ERCB and differ from those applicable to surface mines. Overall, although processing plants are included and provisions are made for remediation and reclamation, the approach adopted for in situ operations is such that security deposits will be a smaller proportion of assessed environmental liability than for surface mining operations.
- The Auditor General of Alberta has commented on the situation for surface mines and noted the current system lacks a reasonable, systematic risk management approach to avoid claims on the public purse arising from inadequate financial security. The same concern applies to in situ projects.
- For oil sands operations, financial security deposits typically take the form of irrevocable letters of credit issued by financial institutions. In the event of failure to perform on the part

of oil sands operators, liability, as determined by the size of the letter of credit, reverts to the issuing institution.

- The ability of financial institutions authorized to issue letters of credits to deliver payment on major reclamation liability is a concern.
- Responsible government management of this issue must be demonstrated better than has been demonstrated to date.

8. Does oil sands development cause serious human health effects in regional communities?

- Environmental contaminants at current levels of exposure are unlikely to cause major health impacts for the general population. Projected additional emissions from expanded operations are not likely to change this expectation. In particular, there is no credible evidence to support the commonly repeated media accounts of excess cancer in Fort Chipweyan being caused by contaminants released by oil sands operations, notably polycyclic aromatic hydrocarbons (PAH) and arsenic. In particular, common references to PAH in relation to human cancer risk have been loose and inconsistent with the scientific understanding of human cancer risk from this class of compounds.
- Notwithstanding the evidence, there appears to be a strong and recurring perception of potential cumulative health risks by many community members, which itself can lead to stress-related health issues in the affected communities.
- There are commonly perceived beneficial impacts of oil sands developments related to increased income and employment.
- As is commonly the case in boom-town style developments, there are major negative effects on community health due to several simultaneous pressures on individuals, families, and infrastructure. These include general price inflation, extreme housing shortages, labour shortages in most sectors, family stress, drug and alcohol abuse, increased crime, and other social negative impacts related to inadequate public health and municipal services. Community health status in the oil sands region is lower than the provincial average, which is dominated by Calgary and Edmonton data, but also poorer than that in the more comparable Peace Country region which has had its own, less intense, economic boom.
- Despite extensive searching of publicly accessible documents, no assessment could be found related to oil sands development for occupational health status in the industry or human health risks from technological disasters.

9. ***Are cumulative human and environmental impacts of oil sands development being adequately managed (including monitoring and data access) by the current regulatory system?***

- Cumulative environmental impact assessment has been repeatedly raised as a concern in hearings addressing individual project EIAs and has been acknowledged as a priority need for regulatory reform by the Government of Alberta.

- A basic requirement for effective cumulative environmental assessment is easily accessible environmental data, preferably accessible in a central registry. Currently, relevant data are only readily accessible for air quality from the Wood Buffalo Environmental Association (WBEA) and air emissions from the National Pollutant Release Inventory (NPRI) database. Data collected by RAMP, the Cumulative Environmental Management Association (CEMA), environmental monitoring for regulatory approvals, and individual project EIA studies, are not uniformly and readily accessible.

- Cumulative impact assessment can only be achieved if these environmental data are analyzed on an ongoing basis.

- Cumulative environmental assessment requires determination of the ecological capacity in the region to identify limits that need to apply to individual project approvals.

- Water withdrawal limits developed in the Water Management Framework are based on historical flow data and an assessment of ecological in-stream flow needs by AENV in collaboration with DFO and ongoing work is required to validate these assumptions.

- Regional air quality and cumulative air emissions have been addressed to some degree in individual project EIAs, but better overall coordination of ongoing analysis is needed.

- There is strong indication that community health is being impacted cumulatively by the boom-town effect, but there is no specific program evident to address this problem.

- Access to environmental data and the associated transparency are essential to public confidence in environmental management.

- Government needs to take leadership to enable coordination and data access that is necessary and efforts to date fail to meet the scale of the challenge.

- In recent years a practice has emerged that does not support a cumulative environmental assessment approach by the Government of Alberta. AENV and SRD have not been participating in the ERCB public hearings which are held to inform the public interest decision which the ERCB must make concerning individual projects. This practice means the ERCB must make its public interest decision without benefit of input from Alberta's primary environmental regulators. AENV, in turn, is faced with issuing environmental

approvals and licenses (EPEA, WA) to projects that have been approved by the ERCB without benefit of publicly accessible AENV input at the hearing stage.

- Despite many clear issues of valid federal interest, the profile of relevant federal agencies has been low.

- The purpose statements of EPEA and WA (see Section 5.3.3) provide clear guidance to the Government of Alberta about what needs to be achieved in managing environmental impacts from oil sands development; the government simply needs to respect the letter of its own legislation in this regard.

10. Is the oil sands industry collectively Canada's largest emitter for air pollutants other than greenhouse gases?

- The summary in Section 7.2 (Table 7.2) shows that for the major criteria air pollutants ($PM_{2.5}$, SO_x, NO_x, VOC, and CO), the contribution of the oil sands industry to the total of all Canadian industrial sources plus electric power generation utilities in 2007 and 2008 ranges from a low of 1.7% for CO to a maximum of 9.2 % for VOC. The oil sands industry ranked among major industrial categories plus electric power generation utilities for emissions in 2007 and 2008 from a low of twelfth for $PM_{2.5}$ to a high of third for VOC and NO_x. To become the largest industrial emitter in Canada, in 2007 or 2008 the oil sands industry would have to increase by more than five-fold for SO_x and VOC or by more than seven-fold for any other category of criteria air pollutants.

- For the four categories of toxic air pollutants (carcinogenic PAH, Pb, Cd, Hg) summarized by NPRI for major industrial categories in 2007, the contribution of the oil sands industry to the total Canadian industrial sources plus electric power generation utilities in 2007 and 2008 range from a low of 0.01% for carcinogenic PAH to a maximum of 2.0% for mercury. The oil sands industry ranked among major industrial categories plus electric power generation utilities for emissions in 2007 and 2008 from a low of eighth for lead to a high of fifth for mercury. In 2007 and 2008, the oil sands industry would have to increase emissions by more than 15-fold to become the largest industrial emitter in Canada for any category of the four toxic air pollutants available in NPRI for comparison. The most recent industry data summary available was for 2008 which allowed a cross-industry comparison.

- The proportion of air emissions from the oil sands industry is expected to grow over the next decade, but, as noted above, will not lead to the oil sands industry being the worst polluter in any category.

- The 2007 NPRI data do not cover volatile organic compounds (VOC) from tailings ponds, a source that is important and should be reflected in future NPRI summaries. The 2008 NPRI data show about a three-fold overall increase in VOC from 2007 driven by a major increase

in reported fugitive emission, presumably from tailings ponds. These estimates would allow judgement of the degree of improved air pollution control that will be necessary.

- The odour emissions problems experienced over the past two years need to be resolved.
- The expeditious and consistent adoption of current BATEA used by the power generation industry by oil sands operation for NO_x and other air pollutants is necessary.

11. Are greenhouse gas emissions from the oil sands industry being adequately controlled?

- In response to the Copenhagen Accord, the Government of Canada has made an economy-wide commitment to reduce GHG emissions by 17%, relative to 2005 levels, by 2020.
- The current proportion of Canada's total direct GHG emissions attributable to the oil sands industry is about 5%, compared with 16% for fossil fuel-fired power generation and 27% for transportation, based on 2008 Environment Canada data.
- Canada's GHG emissions have been rising over the period covered by the Kyoto Protocol, an overall increase of 142 million tonnes (24%) from 1990 to 2008. More than 80% of that increase in Canada's GHG emissions was independent of the growth in GHG emissions from the oil sands industry. The total 2008 GHG emissions related to the oil sands were about 37 million tonnes in 2008 and the increase in GHG emissions from the oil sands from 1990 to 2008 was roughly 20 million tonnes because of the growth in bitumen production (Env Can 2010a).
- In 2008, oil sands direct GHG emissions were about 19% of total Canadian transportation GHG emissions. About two-thirds of total oil demand in North America (i.e., the demand driving oil sands production) arises from the transportation sector.
- There are some important technological initiatives reducing oil sands GHG emissions and there is some promise for further reductions in GHG emissions intensity (GHG emitted per unit of production) as noted in Question 1 above. The oil sands industry has reduced its GHG emissions intensity by 39% from 1990 to 2008 according to Environment Canada (Env Can 2010a).
- GHG emissions intensity is currently higher for in situ than surface mining projects and in situ bitumen production is expected to grow more than surface mining bitumen production.
- In 2003 Alberta adopted the first legislated system in North America for regulating GHG emissions. Regulations in effect for large industry (established emitters of more than 100,000 tonnes of CO_2e per year in any of 2003 to 2006) are required to reduce their emissions intensity beginning in 2007 by 12% based on the average emissions intensity from 2003 to 2006. Emitters who miss their GHG emission targets can purchase credits to meet their regulated limit at the rate of $15/tonne of CO_2e with the funds collected managed

by a Government of Alberta agency investing in research into technology for reducing GHG emissions.

- The Government of Alberta has committed a $2 billion investment towards CCS industrial demonstration projects. Although CCS may achieve a major reduction in Alberta GHG emissions, the geology of the oil sands region of northeastern Alberta is not a good candidate for CO_2 storage. Overall, CCS is likely a better technology for coal-fired power generation than for oil sands production.

- The predicted future of GHG emissions from the oil sands industry pose a major and growing challenge to Canada's ability to meet national GHG emission reduction targets in keeping with international GHG reduction targets.

12. Is the oil sands industry the most environmentally destructive project on earth, as has been suggested by some media and declared critics of the industry?

- Based on our review of the publicly accessible evidence, a claim of such global magnitude is not accurate. Despite the lack of evidence to support this particular view, it has gained considerable traction with the media and it now pervades the internet. This depiction is clearly aided by the photographs of ugly surface-mined landscapes, but the claims of global supremacy for oil sands environmental impacts do not accord with any credible quantitative evidence of environmental damage.

- Based on the most recently available summary data (2007) from Environment Canada's NPRI database, the oil sands industry is no higher than fourth in industrial categories for air emissions of major criteria air pollutants.

- Likewise the oil sands industry ranks in the major industry categories for toxic emissions as fifth for mercury, sixth for cadmium, ninth for lead, and ninth for the four carcinogenic PAH available for summary comparison.

- In all cases for both criteria air pollutants and toxic emissions, at least a five-fold increase in emissions would be necessary for the oil sands industry to become the first ranked industrial emitter in Canada, meaning that no foreseeable oil sands growth scenario could lead to the oil sands industry being the largest category of industrial emitters in Canada, let alone the world, for any pollutant.

- The current proportion of Canada's total direct GHG emissions attributable to the oil sands industry is about 5% compared with 16% for fossil fuel-fired power generation and 27% for transportation, based on 2008 data. Oil sands GHG emissions are currently 0.08% of estimated global GHG emissions.

- Elimination of oil sands GHG emissions will not eliminate or substantially lessen the immense challenge facing the world to reduce GHG emissions. Notwithstanding that

reality, GHG emissions from the oil sands industry pose a major and a growing challenge to Canada being able to meet national GHG emission reduction targets in keeping with international commitments.

- As of March 2009, 602 km^2 have been disturbed by oil sands mining operations in the past 40 years, with a major acceleration in the rate of mining over the past 10 years. The cumulative area disturbed by oil sands surface mining is equivalent to about 90% of the area of the City of Edmonton (population 782,000)

- The ultimate total potentially surface–mineable area of the oil sands deposit is about 4,800 km^2, which is about two-thirds of the greater Toronto metropolitan area (population over 5.5 million) (Greater Toronto 2010).

- Mines were estimated to occupy about 3,700 km^2 of the United States in 1980 (Barney 1980) and 20,000 km^2 of China in 1989, with an estimated rate of addition of 200 km^2 mining–affected land per year in China (Guo et al. 1989). For other comparisons of major human activities causing land impact, the James Bay hydroelectric project flooded at least 9,700 km^2 of boreal forest in northern Quebec (Berkes 1988) and the cumulative net area of forest loss in the five years between 2000 and 2005 was 1,010 km^2 in North America, 40,400 km^2 in Africa, and 42,510 km^2 in South America (FAO 2006). Surface mining and tailings ponds in the oil sands are concentrated in one area which may increase the local impact.

- Open pit mining in any application causes a substantial impact and the areal extent of oil sands open pit surface mining is considerable. Conventional tailings ponds are a visual blot on the landscape and pose a continuous threat to migratory waterfowl. There is clearly scope and need for more rapid reclamation of disturbed areas than has been implemented to date.

- Preliminary NPRI 2009 reporting of tailings and waste rock from mines and mills indicates oil sands mines total 10% of total tailings and waste rock produced in Canada compared with 54% for metal ore mining and 25% for iron ore mining.

- Fresh surface water use is mainly associated with surface mining operations and although water demand is substantial, it is not an unsustainable fraction of available water flow in the Athabasca River (further details in response to Question 3 above and in Section 8.2.1).

- Consistent evidence the oil sands industry is a major polluter of surface waters has not been demonstrated. Pollution of groundwater is less certain, but there is no evidence potential pollution of local or regional groundwater is substantial on national or global scales.

- The claim by some critics of the oil sands industry that it is the most environmentally destructive project on earth is not supported by the evidence. However, for Canada and Alberta, the oil sands industry involves major environmental issues on many fronts which must be addressed as a high priority.

Panel Observations on Closing the Gap

Our mandate was not to judge the economic benefits of oil sands development but to document them as a relevant matter of background. The magnitude of economic development of the oil sands and its contribution to the Albertan and Canadian economies largely speaks for itself. Our evaluation of environmental and health impacts has been addressed to a moving target; many things are happening while we have been doing our evaluation. Consequently, we cannot claim to know everything that is currently underway or which has been achieved (see Section 1.2).

Some of the challenges involved in managing environmental and health issues associated with oil sands development arise from the large physical scale, rapid rate of expansion, the long project life, and involvement of multiple developers. These circumstances all contribute to challenges in achieving a coordinated and integrated environmental management approach. An overall theme of fragmentation vs. integration is a recurring challenge, particularly for cumulative impact assessment, an objective that is almost universally recognized as essential.

The Government of Alberta has reviewed many aspects bearing on health and social impacts of oil sands development, including seeking stakeholder perspectives on these issues. In response to the stakeholder survey, the Government of Alberta has proposed six strategies (Gov AB 2009a) to pursue regarding oil sands.

1. *Develop Alberta's oil sands in an environmentally responsible way.*
2. *Promote healthy communities and a quality of life that attracts and retains individuals, families, and businesses.*
3. *Maximize long-term value for all Albertans through economic growth, stability, and resource optimization.*
4. *Strengthen our proactive approach to Aboriginal consultation with a view to reconciling interests.*
5. *Maximize research and innovation to support sustainable development and unlock the potential of Alberta's oil sands.*
6. *Increase available information, develop measurement systems, and enhance accountability in the management of the oil sands.*

A number of actions were identified to implement the strategies. These actions are mainly process recommendations, which while valuable, do not specify end targets. In our review, we have identified specific needs for improvement that are generally, and in some cases specifically, applicable to these strategies. Although we may emphasize different elements, many of our findings should not come as a surprise, given the stakeholder feedback which is already reflected in the Government of Alberta plan for environmentally responsible oil sands development. The important issue, given the pace of oil sands development which has occurred, is how quickly meaningful action will be taken. As of the time

of writing this report, there was little evidence available to us that implementation of meaningful improvements has begun or will be achieved in an adequately rapid time frame.

Based on our review of publicly available evidence, we offer the following observations.

Environmental Assessment

We have identified deficiencies in environmental assessment practices compared with international best practice guidance from guidelines promoted by Canadian agencies, international agencies, and industrial associations (e.g., IAIA, IPIECA, OECD, OGP, ICMM, World Bank). Notably, there has generally been inadequate overall risk assessment for technological and natural disasters, assessment of community health impacts (negative and positive), integrated and cumulative ecological impact assessment, and assessment of regional socio-economic impacts.

The cumulative impact assessment challenge requires much better integration of data gathering and assessment than is evident under current practices. Water issues are being addressed by RAMP, air issues by WBEA, and these and other environmental issues by CEMA. These activities require effective stakeholder input, coordinated cross-media data analyses, and meaningful scientific oversight to assure continuous improvement in scientific methods, analyses, and ultimately to project approvals and environmental protection practices. These needs suggest that some agency must ultimately be responsible for integrating all of these monitoring and analytical activities towards the overall goal of assuring environmentally responsible development. The credibility of this agency and transparency of its activities are vital.

Tangible improvements could be achieved by:

- Undertaking a thorough comparison of current practices in environmental assessment against international practices, including health, social, economic, environmental, and sustainable development components, with a view to identifying international best practices. This evaluation must be done in an open manner. The findings should establish a benchmark for these assessments and must be updated regularly and be publicly accessible.
- Implementing a central repository of regional environmental, community health, and infrastructure data that provides effective public access.
- Implementing cumulative assessment, which requires the foregoing and a coordinated effort to review, analyze, and interpret regional data to set targets with a publicly accessible process that define cumulative capacity limits, as has been done with water use.

Community Health Disparities

We identified major community health disparities for the oil sands region compared to the provincial average and a similar resource development region of the province. We were unable to identify any public health intervention programs specifically targeted towards resolving these conditions that are largely symptomatic of boom-town conditions. A coordinated public health effort needs to be organized to address the evident health disparities. In particular, the Government of Alberta undertook

a major review of needs for dealing with the oil sands development boom with the Radke report (Gov AB 2006) and many actions have been taken to implement its wide-ranging recommendations. Given the evidence for substantial community health disparities in the oil sands region, a current review of the evidence and community health needs would be valuable for developing meaningful and timely responses.

Role of Governments and Regulatory Agencies

The current visibility of relevant provincial and federal agencies, in particular, in dealing with the major environmental challenges is low and is generally not in line with the scale of those challenges. The Government of Alberta has a government-wide portal on its website to address oil sands, but the current content is largely public relations documents regarding the industry. There is a need for a substantive, publicly accessible, cross-government source where evidence on identifying problems and tangible government progress in dealing with those issues can be tracked.

Albertans clearly own the oil sands resource, thus their elected government, as the agent of the owners, has a critical leadership responsibility and role in determining how and under what conditions that resource will be developed. Recently, there have been some important steps taken to demonstrate the leadership required, notably as itemized in the Implementation Plan (Gov AB 2009b) for the strategies outlined in Responsible Actions (Gov AB 2009a). A key test moving forward will be in how effectively and quickly these actions are implemented regardless of the pressure arising from oil sands development applications that will be driven by market demand.

In view of the growing international, national, and local attention oil sands development is attracting, the public interest determination required of the ERCB in judging the next round of oil sands project approvals is becoming more challenging. Based on the specific deficiencies that we have identified and the important lack of cumulative analysis on many environmental and social issues, the ERCB faces difficult public interest determinations on future projects unless these information deficiencies, especially on cumulative impacts, are corrected. Accordingly, the necessary studies need to be completed with highest priority to assure a sound evidence basis for the public interest decisions that the ERCB's enabling legislation obliges it to make for the people of Alberta on project applications.

First Nations and Métis Issues

Concerns about health risks from traditional Aboriginal land use need to be addressed by a focused data gathering exercise on potential contaminant exposure from traditional lifestyles, rather than performing health risk assessments with inadequate local data which drive those assessments towards over-reliance on models and assumptions.

Judging the magnitude of negative impacts requires studies on current traditional activity patterns and current attitudes towards development among potentially affected First Nations and Métis populations. Recent projects have conducted extensive traditional use studies and maintained substantial consultations with affected First Nations and Métis populations. Consultations need to achieve meaningful agreements that will allow First Nations and Métis populations affected by developments

to participate tangibly in benefits of development, rather than simply having to adapt to negative impacts.

Financial Security

The need for new policy to protect Albertans from financial liabilities from reclamation of oil sands operations has been recognized by the Provincial Auditor General and more recently by the Government of Alberta (2009). For many reasons, the Government of Alberta should proceed with efforts to enhance financial liability management programs applicable to *both* oil sands surface mining and in situ projects. Such efforts are especially needed in light of evidence of widespread insufficient financial security in mining cases elsewhere in Canada and in the United States. A systematic approach to determining liability and the required financial security should be actively considered, recognizing that the approach adopted must be flexible enough to accommodate differences in the relevant aspects of surface mining and in situ activities.

The process leading to adoption of new policy in this area should be the subject of broad stakeholder and public consultation. The approach ultimately adopted and implemented should be the subject of detailed, publicly available documentation to assure Albertans their valid interests are truly protected.

Given the nature of activities and existing policy in this area, the following issues of particular relevance to surface mining activities should be addressed. Financial security should apply to remediation (contaminant clean-up) and reclamation (already the case for in situ operations). Extraction plants and upgraders should be subject to financial security requirements (already the case for in situ operations). All oil sands mining operations should be subject to financial security requirements that are related to reclamation and remediation liabilities and not to production volume as is currently the case for some older mines.

Given the substantial magnitude of financial risks involved, there appears to be a compelling need to develop and implement an overall financial risk management approach to address this risk to the public purse.

GHGs

There is a clear challenge for Canada to meet overall GHG emission reduction targets while oil sands industry GHG emissions rise because of growth in production even while the industry has achieved reduced GHG emissions intensity. The provincial and federal governments need to recognize that the tangible commitments evident to date are likely still inadequate for Canada to meet its economy-wide GHG emissions target.

Air Quality

Given the major air emissions associated with oil sands operations, AENV needs to rigorously maintain a requirement for BATEA in all operating approvals issued. This is not a decision that industry can simply veto, it must be a responsibility of a competent environmental regulator. This means there must be the political will demonstrated to support technical decisions made by the

regulator's technical personnel. The odour problems encountered in recent years are substantial issues that must be similarly understood and effectively resolved.

Oil Sands Lexicon

Developing common definitions for key technical and policy terms, such as reclamation vs. restoration, equivalent land capability, and "in the public interest," is clearly required to minimize the negative impacts of differing interpretation of these terms among all stakeholders. Consideration will have to be given to how these terms can be standardized and clearly delineated for existing projects that are based on older and variable interpretations of the terms.

Progressive Reclamation

The real barriers to progressive land reclamation need to be explained. Intuitively, most would agree that reclaiming land soon after it is disturbed is a good thing which needs to be encouraged. Various reasons are given for not implementing progressive reclamation, but a full analysis of the barriers has not been done. Regardless, there appears to be more opportunity to implement progressive reclamation than past practices have demonstrated and the need to do better is compelling.

Protection of Waterfowl

The current practices for protecting waterfowl from the lethal risks posed by tailings ponds have been shown by the April 2008 and October 2010 incidents to be seriously inadequate. A new integrated approach focusing on doing more to prevent bitumen from reaching the tailings ponds, more to recover floating bitumen, and more to segregate bitumen from the majority of the tailings ponds surfaces needs to be pursued in light of these recent environmental failures. Even without the unacceptable toll of waterfowl deaths occurring, such measures are surely within the mandate of the ERCB because avoiding loss and maximizing recovery of bitumen is clearly conserving an energy resource. For the operators, lost bitumen represents lost income.

Industry Leadership

The oil sands industry can demonstrate leadership in developing future project proposals by implementing health impact assessment (HIA) guidelines as proposed by their international peer group. They should produce better consideration of cumulative impacts on community health, including the economic quantification of negative impacts and infrastructure spending.

Research Needs

Although research money is being invested in keeping with Strategy 5 of Responsible Actions (Gov AB 2009a), there is a need to ensure that research addresses the critical issues and is effectively published to ensure current and future research will benefit from work that has already been completed. A more intensive, time-sensitive, and integrated approach is needed to address the management of the critical issues, as follows:

- There is a need for a commitment to and emphasis on studying long-term effects (notably in reclamation and groundwater) beyond what is currently evident in published research.
- Continued efforts need to be directed at developing and improving alternative bitumen-recovery technologies that have a smaller environmental footprint and entail lower energy and water use.
- A regional groundwater framework to define a baseline for water quality and quantity is required. More research is needed to better understand and quantify interactions between groundwater and surface water.
- Reclamation of wet landscapes poses challenges which require intensive and coordinated research. There appears to be a need to simultaneously develop feasible process-affected water treatment vs. the EPL option for managing residual process water as a given project reaches termination. Regulatory decisions on water management are ultimately going to be necessary. Given the long time lines involved, developing discharge criteria for treated, process-affected waters should not be delayed any longer.
- All levels of government should establish a research capacity to monitor and investigate independently the current health impacts of oil sands projects. This initiative needs to be appropriately and adequately funded on a continuing basis by the developments generating the issues and be conducted under independent scientific guidance.
- Monitoring of health impacts should be undertaken on both health outcomes and health determinants. Health outcomes should include, for example, incidence of infectious and chronic diseases and mental health, incidence of physical injury and poisoning, and occupational health; while key health determinants should include, for example, effects on local health and social care services.
- Specific public health interventions should be determined and designed for the Regional Municipality of Wood Buffalo and other nearby regions found to be affected by oil sands development, to address the current health disparities described in Section 10.

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- "Value of Sales": Canadian Association of Petroleum Producers (CAPP) *Statistical Handbook*, Table 04-19B;
- "Net Value": calculated as "Value of Sales" minus (Operating Expenditures, Royalties, and Bonus Payments) – "Operating Expenditures" and "Royalties" taken from CAPP *Statistical Handbook*, Table 04-16B; "Bonus Payments" from Alberta Department of Energy *Oil Sands Public Offerings Statistics*;

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APPENDICES

APPENDIX A1 RECENT INVESTMENT IN OIL SANDS DEVELOPMENT

As noted in Section 1, investment in oil sands production facilities has grown sharply since the mid-1990s. In this short Appendix, we document further the magnitude of the investment "boom" in Alberta's oil sands, and outline some of the key factors that have shaped the pace of development and will continue to drive activities in the future.

Investment in oil sands development reached phenomenal heights during the first decade of the new century, both in terms of levels (Figure A1.1) and as a share of the total investment in the Canadian upstream oil and gas industry (Figure A1.2). In 2000, for example, oil sands capital expenditures reached $4.2 billion—almost 75% higher than the level of investment realized in 1999 ($2.4 billion), which itself had been by far the historical peak. This rush to develop the oil sands continued for most of the decade; the growth in investment was especially strong between 2004 and 2007, where *annual* capital expenditures more than *tripled* in size in that three-year period. In relative terms, Alberta's oil sands also became a much more important destination for investment in the Canadian upstream oil and gas industry. Between 1986 and 1999, oil sands investment accounted for approximately 10% of the Canadian industry total; the comparable value for the subsequent decade is 27%.

Figure A1.3 helps us understand a key element of the dynamics that drove this growth in investment activity. At the beginning of 1999, for example, the (Canadian-dollar) price of West Texas Intermediate (WTI) crude oil—a key North American light/medium crude—was approximately $20 /bbl. One year later, that price had doubled and then, with the exception of a few months towards the end of 2001, remained above that value for the rest of the ensuing decade. Figure A1.3 also reminds us that the average price of Alberta-produced light and medium crudes tracked the evolution of the WTI price for the period under consideration. Indeed, in the course of a five-year period between mid-2003 and mid-2008, both of these prices rose from about $40 to a peak of some $135/bbl—an increase of more than 200%.

By 2007, it was clear that cost pressures were beginning to accompany this frenetic pace of activity and that the level of production and upgrading capacity that could be installed and operated for any given level of investment was falling. Researchers at the Canadian Energy Research Institute (CERI) follow developments in the oil sands and periodically report on cost conditions prevailing in this industry. Extracts from two published reports give an indication of the magnitude of the cost pressures that emerged during that period. In 2007, the situation was characterized as follows:

> *Total supply costs for bitumen recovery – CSS [cyclic steam stimulation], SAGD [steam-assisted gravity drainage], and mining operations – have increased by 23, 70, and 86 percent since the 2006 CERI analysis. The greatest increase…has been in operating costs, which have increased two- to five-fold.* (McColl 2007, p. vi).

Sharp cost increases were also noted the following year:

> *Total supply costs for bitumen recovery have increased by a range of 25 to 50 percent since the 2007 CERI analysis. We do not believe that this pattern of increasing supply costs is indicative of future costs.* (McColl and Slagorsky 2008, p. xi).

As the International Energy Agency (IEA) (2008, pp. 311–317) reminds us, upstream oil and gas cost pressures were a global phenomenon from the beginning of the decade. The sustained increases in world oil prices drove upstream oil and gas activity levels to astonishing heights around the world. As a result, key materials (e.g., steel), equipment (e.g., drilling rigs), and services (e.g., engineering) were in relatively short supply, which resulted in upward pressure on development costs. These global pressures were clearly felt by Alberta's oil sands industry and their effects were compounded by cost pressures of a more local nature, resulting from such things as shortages of some types of skilled labour.

Rising oil and gas development costs resulted in even greater pressures on operators in 2008 as world oil prices fell sharply: during the course of that year, oil prices dropped by as much as 70%, as Figure A1.3 shows. In Alberta's oil sands, a number of projects were cancelled or delayed, resulting in investment levels that stagnated and even fell as a share of the total Canadian upstream capital expenditures. Overall, lower oil and gas industry activity levels were experienced around the world, resulting in the emergence of downward pressure on development costs in the first half of 2009, as IEA (2009, pp. 448–450) highlights. The situation was no different in Alberta's oil sands industry, as the following excerpt from a 2009 CERI study indicates:

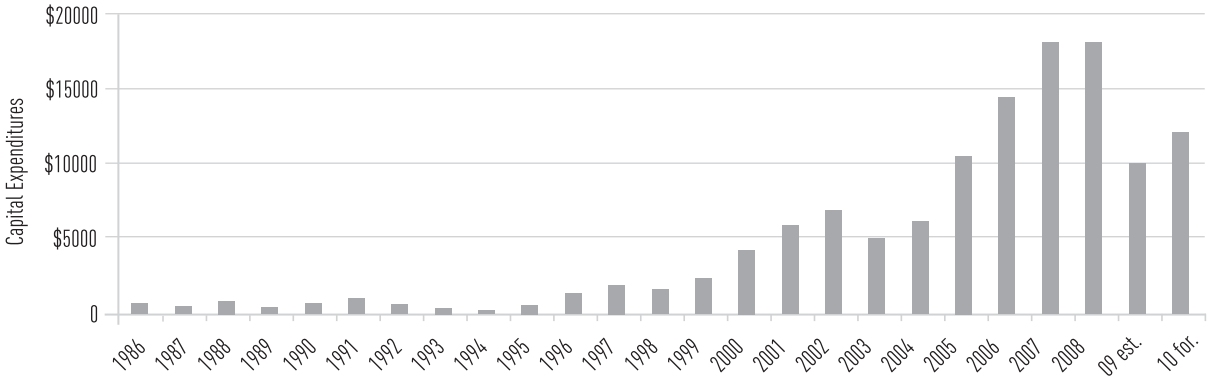
> *Over the past year, CERI has estimated that the capital costs for constructing oil sands projects declined by fifteen percent, while operating costs dropped by thirteen percent.* (McColl et al. 2009, p. viii; emphasis in original)

As far as the high-cost oil sands deposits are concerned, the effects of the sharp decrease in crude oil prices outstripped those of the smaller decreases in development costs leading to an estimated 40% reduction in capital expenditures in 2009. The pressure was particularly strong on the construction of new upgrading capacity since the drop in price levels was also accompanied by a narrowing of the price differential (in both absolute and relative terms) between light/medium crudes (including synthetic crude oil, SCO) and bitumen, as is evident in Figure A1.3. Between January 2000 and December 2008, for example, the bitumen price (measured at Cold Lake) was about 56.5% of the average price of Alberta light and medium crude production, whereas since January 2009 this proportion has increased to an average of some 76.5%, thus making bitumen production relatively more attractive but also squeezing the net revenue base for upgrading activities. In other words, smaller price differentials mean that the margin between the revenues from the sale of SCO and the cost of a key input—bitumen—is also smaller, thus acting to reduce the profitability and hence the attractiveness of investment in upgrading activities.

Crude oil prices have recovered since the beginning of 2009. While still much lower than the peaks reached in mid-2008, these prices have roughly doubled in the fifteen months separating the beginning of 2009 and the end of the period covered by Figure A1.3. A number of oil sands production projects are now scheduled to proceed, and a key industry association has recently forecasted an increase in capital spending for Alberta's oil sands industry as a whole (CAPP 2010). It would appear that the pace of activity in oil sands areas is once again on an upswing.

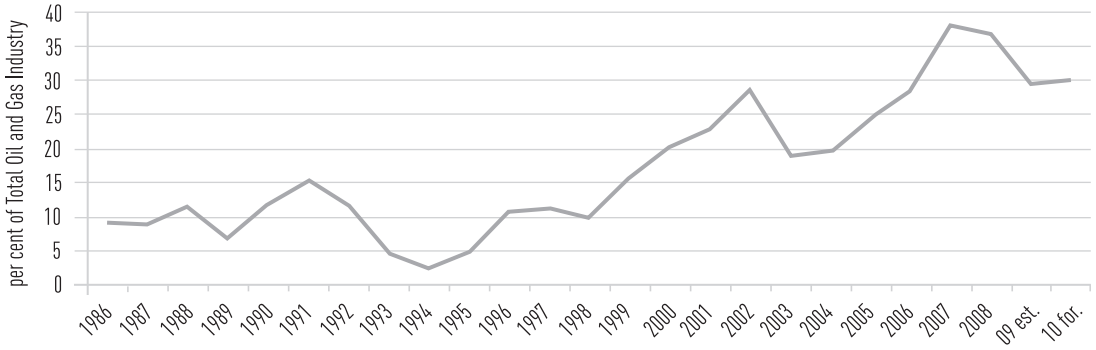
The perspective developed above is that three key factors, and the interaction among them, have materially affected the evolution of investment levels in Alberta's oil sands over the last decade. All else held equal, oil price increases encourage higher development activity levels. However, large and sustained price increases will also drive up upstream development costs. In the short term, such cost increases can be substantial, especially if input supply constraints are experienced. A sharp fall in oil prices will then act to squeeze the profitability of upstream investments, even more so if input prices are relatively slow to adjust. While these effects will be felt in all segments of the oil industry, they will be relatively stronger for high-cost production (such as Alberta's oil sands) since the associated profitability margins are smaller to begin with. Finally, another factor comes into play as far as oil sands are concerned, namely the evolution of price differentials between light/medium crudes (including SCO) and bitumen. Given light/medium prices and cost conditions, smaller price differentials mean higher bitumen prices thus making investments in oil sands *production* more appealing. However, these same conditions also make investments in new *upgrading* capacity less attractive since, all else being equal, such conditions reduce the profitability of upgrading activities.

Figure A1.1 Oil sands capital expenditures, 1986–2010 (millions of current Canadian dollars)



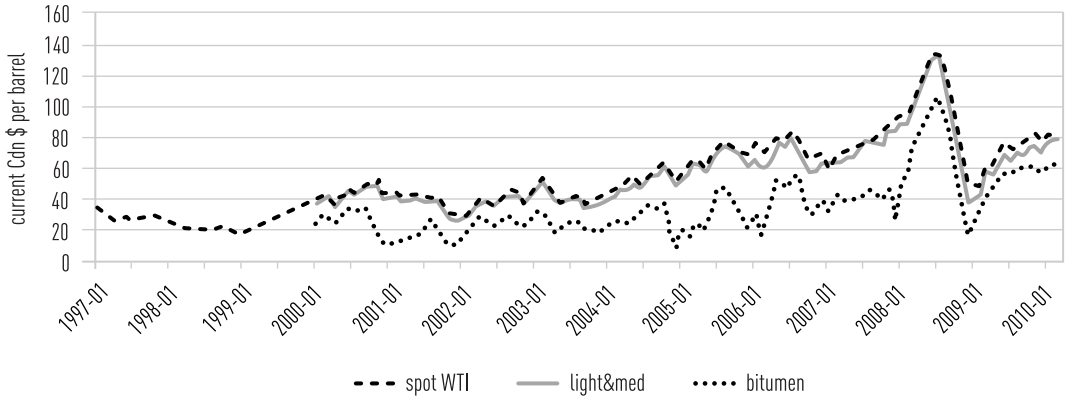
Source: CAPP *Statistical Handbook* (Tables 04-16A and 04-16B) for 1986 to 2008; CAPP (2010) for 2009 estimate and 2010 forecast

Figure A1.2 Capital expenditures, oil sands as a share of total upstream oil and gas industry in Canada, 1986–2010



Source: Calculations using information from Figure A1.1 and from CAPP *Statistical Handbook* (Table 04-02B) for 1986 to 2008; CAPP (2010) for 2009 estimate and 2010 forecast

Figure A1.3 Selected crude oil prices, January 1997 to March 2010



Source: US Energy Information Administration (for US-dollar spot price of WTI) and Statistics Canada (for exchange rate); ERCB serial publication ST3 (Alberta Energy Resource Industries Monthly Statistics) for the other two price series.

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Appendix A1

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APPENDIX A2 PANEL PROCESS

REQUEST FOR INFORMATION ADDRESSED TO STAKEHOLDERS

9 November 2009

Dear stakeholder:

Re: Evidence on Environmental and Health Impacts of the Oil Sands Industry

The Royal Society of Canada, The Academies of Arts, Humanities and Sciences of Canada have commissioned an Expert Panel to address the Environmental and Health Impacts of Canada's Oil Sands Industry. The Expert Panel will be acquiring and reviewing available evidence over the coming months.
Our scope is described in the attached press release and the working Terms of Reference for the Panel can be found at www.rsc.ca/expertpanels.php .

To assure that this Expert Panel has access to the best available evidence, I am asking you or appropriate staff of your organization, to provide, as soon as feasible, but no later than December 31, 2009, copies of any publicly available reports that specifically contain information or scientific evidence that is directly relevant to our review.

Our panel is explicitly **not** seeking any submissions, position statements or other forms of advocacy regarding any of these issues.

Please send relevant paper documents to me at:

Dr. Steve E. Hrudey
Chair, *Royal Society of Canada Expert Panel on Oil Sands*
10-102 Clinical Sciences Building
University of Alberta
Edmonton, AB T6G 2G3

Electronic documents are preferred, wherever possible. These may be sent to me by email at steve.hrudey@ualberta.ca. Please direct any inquiries you may have about this request to me by email.

Please also advise me of any organization(s) that you believe may be interested in this request, or, alternatively, you may forward them a copy of this letter.

Thank you for your attention and assistance.

Yours sincerely,

Steve E. Hrudey, FRSC, FSRA, PhD, DSc(Eng), PEng
Professor Emeritus

List of stakeholders who were sent the information request letter

Alberta Department of Energy
Alberta Ecotrust Foundation
Alberta Environment
Alberta Environmental Network
Alberta Fish & Game Association
Alberta Health and Wellness
Alberta Sustainable Resource Development
Alberta Wilderness Association
Alberta's Industrial Heartland Association
Athabasca Chipewyan First Nation
Athabasca Tribal Council
Canadian Association of Petroleum Producers
Canadian Energy Pipeline Association
Canadian Environmental Assessment Agency
Canadian Environmental Network
Canadian Heavy Oil Association
Canadian Medical Association
Canadian Public Health Association
Canadian Society of Environmental Biologists / SCBE
Canadian Society of Petroleum Geologists
Chipewyan Prairie First Nation
Clean Air Strategic Alliance
CNHHE-RCSHE
COPD & Asthma Network of Alberta (CANA)
CPAWS Northern Alberta Chapter
Department of Health and Social Services
Ducks Unlimited Canada
Energy Council of Canada
Energy Resources Conservation Board
Environment and Natural Resources
Environment Canada
Environmental Law Centre
Executive Council
Fisheries & Oceans Canada
Fort McKay First Nation
Fort McMurray # 468 First Nation
Greenpeace Canada
Health Canada
Indian Affairs and Northern Development
Industry Canada
Lakeland Industry & Community Association
Land Stewardship Centre of Canada
Metis Settlements General Council

Mikisew Cree First Nation
National Energy Board
Natural Resources Canada
Peace River Environmental Society
Privy Council Office
Regional Municipality of Wood Buffalo
Saskatchewan Environment
Saskatchewan Health
The Edmonton Friends of the North Environmental Society
The Lung Association, Alberta & NWT
The Oil Sands Developers Group
The Pembina Institute
The Sierra Club of Canada, Prairie Chapter
Toxics Watch Society of Alberta
Trout Unlimited Canada

List of stakeholder responses received

Alberta Executive Council on behalf of

- Alberta Energy
- Alberta Environment
- Alberta Health and Wellness
- Alberta Sustainable Resource Development

Alberta Wilderness Association
Canadian Association of Petroleum Producers
Canadian Environmental Assessment Agency
Canadian Heavy Oil Association
Canadian Public Health Association
Environment and Natural Resources, NWT
Environment Canada
Fisheries & Oceans Canada
Health Canada
Indian Affairs and Northern Development
Industry Canada
National Energy Board
Natural Resources Canada
Regional Municipality of Wood Buffalo
Saskatchewan Environment
Saskatchewan Health
The Oil Sands Developers Group
The Pembina Institute

Unsolicited Responses

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APPENDIX A3 REGULATORY FRAMEWORK DETAILS

Federal Regulatory Authority

Fisheries Act (FA). This Act prohibits[1] or regulates[2] any work or undertaking that harmfully alters, disrupts, or destroys fish habitat. Section 36(1) provides very broad powers of prohibition of activities that may affect surface waters, while Section 36(2) provides a mechanism for obtaining approval of the Minister[3] for the activity which empowers the Department of Fisheries and Oceans to explicitly review an activity and grant an approval for that activity that will exempt the activity from the broad prohibition under Section 36(1).

The FA also prohibits[4] or regulates[5] the deposit of a deleterious substance[6] into waters frequented by fish. These provisions of Section 36 provide a very broad enforcement power for the release of any water pollutant which can be proven to be deleterious to fish and a corresponding approval power for authorizing the release of deleterious substances into waters frequented by fish. This approval authority was made explicit with the adoption of regulations under the FA for the pulp and paper industry and the metal mining industry, but this program of FA industrial regulation development was suspended in the 1970s before petroleum refining regulations were adopted and no FA regulations apply to the oil sands industry.

The provisions of FA Section 36 regarding impact on fish habitat and/or deposit of deleterious substances also provide a basis for the Minister to require plans and specifications[7] for any proposed activity that may invoke either or both of these prohibitions.

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[1] R.S.C. chap. F-14., "***35. (1)*** *No person shall carry on any work or undertaking that results in the harmful alteration, disruption or destruction of fish habitat."*

[2] Ibid., "***35. (2)*** *No person contravenes subsection (1) by causing the alteration, disruption or destruction of fish habitat by any means or under any conditions authorized by the Minister or under regulations made by the Governor in Council under this Act*."

[3] Currently the Minister is the federal Minister of Fisheries and Oceans.

[4] R.S.C. chap. F-14., "***36. (3)*** *Subject to subsection (4), no person shall deposit or permit the deposit of a deleterious substance of any type in water frequented by fish or in any place under any conditions where the deleterious substance or any other deleterious substance that results from the deposit of the deleterious substance may enter any such water*."

[5] Ibid., "***36. (4)*** *No person contravenes subsection (3) by depositing or permitting the deposit in any water or place of*
(a) waste or pollutant of a type, in a quantity and under conditions authorized by regulations applicable to that water or place made by the Governor in Council under any Act other than this Act; or
(b) a deleterious substance of a class, in a quantity or concentration and under conditions authorized by or pursuant to regulations applicable to that water or place or to any work or undertaking or class thereof, made by the Governor in Council under subsection (5)."

[6] R.S.C. chap. F-14., "***34. (1)*** *'deleterious substance' means*
(a) any substance that, if added to any water, would degrade or alter or form part of a process of degradation or alteration of the quality of that water so that it is rendered or is likely to be rendered deleterious to fish or fish habitat or to the use by man of fish that frequent that water, or
(b) any water that contains a substance in such quantity or concentration, or that has been so treated, processed or changed, by heat or other means, from a natural state that it would, if added to any other water, degrade or alter or form part of a process of degradation or alteration of the quality of that water so that it is rendered or is likely to be rendered deleterious to fish or fish habitat or to the use by man of fish that frequent that water."

[7] Ibid., "***37.*** *(1) Where a person carries on or proposes to carry on any work or undertaking that results or is likely to result in the alteration, disruption or destruction of fish habitat, or in the deposit of a deleterious substance in water frequented by fish or in any place under any conditions where that deleterious substance or any other deleterious substance that results from the deposit of that deleterious substance may enter any such waters, the person shall, on the request of the*

Because oil sands developments, particularly surface mining developments, are likely to disrupt fish habitats and may involve the deposit of a deleterious substance, the foregoing sections of the FA provide direct federal authority to authorize activities and/or to prosecute offences under the provisions discussed.

Navigable Waters Protection Act (NWPA). This Act governs any work that may impact navigable waters in Canada and authorizes the Minister to review and control proposals for works that may have such impact.[8] The Minister in this case is the federal Minister of Transportation. If the entity proposing the work applies to the Minister for approval, the Minister can, depending on the apparent significance of the impact on navigable waters, require publication of notice of the proposed works and there is a 30-day window following publication of that notice for interested persons to provide comments to the Minister.

Because oil sands developments are often of a very large scale and may involve activities and structures in surface waters that qualify as navigable, the NWPA may provide direct federal authority to authorize activities and / or to prosecute offences under NWPA.

Migratory Birds Convention Act (MBCA). This is an Act to implement a Convention for the protection of migratory birds in Canada and the United States. The MBCA has a prohibition of depositing a substance that is harmful to migratory birds that is similar to the FA Section 36(3) prohibition of the depositing a substance deleterious to fish.[9] However, unlike the FA, the MBCA does not provide for the Minister (Environment in this case) to permit the deposit of specified amounts of a harmful substance under specific regulations. The MBCA is currently relevant because Syncrude Canada Ltd.

Minister or without request in the manner and circumstances prescribed by regulations made under paragraph (3)(a), provide the Minister with such plans, specifications, studies, procedures, schedules, analyses, samples or other information relating to the work or undertaking and with such analyses, samples, evaluations, studies or other information relating to the water, place or fish habitat that is or is likely to be affected by the work or undertaking as will enable the Minister to determine

(a) whether the work or undertaking results or is likely to result in any alteration, disruption or destruction of fish habitat that constitutes or would constitute an offence under subsection 40(1) and what measures, if any, would prevent that result or mitigate the effects thereof; or

(b) whether there is or is likely to be a deposit of a deleterious substance by reason of the work or undertaking that constitutes or would constitute an offence under subsection 40(2) and what measures, if any, would prevent that deposit or mitigate the effects thereof.

(2) If, after reviewing any material or information provided under subsection (1) and affording the persons who provided it a reasonable opportunity to make representations, the Minister or a person designated by the Minister is of the opinion that an offence under subsection 40(1) or (2) is being or is likely to be committed, the Minister or a person designated by the Minister may, by order, subject to regulations made pursuant to paragraph (3)(b), or, if there are no such regulations in force, with the approval of the Governor in Council,

(a) require such modifications or additions to the work or undertaking or such modifications to any plans, specifications, procedures or schedules relating thereto as the Minister or a person designated by the Minister considers necessary in the circumstances, or

(b) restrict the operation of the work or undertaking, and, with the approval of the Governor in Council in any case, direct the closing of the work or undertaking for such period as the Minister or a person designated by the Minister considers necessary in the circumstances."

[8] R.S.C. chap. N-22. ***5.*** *(1) No work shall be built or placed in, on, over, under, through or across any navigable water without the Minister's prior approval of the work, its site and the plans for it.*

[9] R.S.C. chap. M-22. "**5.1** (1) *No person or vessel shall deposit a substance that is harmful to migratory birds, or permit such a substance to be deposited, in waters or an area frequented by migratory birds or in a place from which the substance may enter such waters or such an area.*"

has been found guilty under the MBCA for an incident in which more than 1,600 ducks died after becoming oiled when they landed on its Aurora mine tailings pond.

Canadian Environmental Assessment Act (CEAA). This Act establishes a federal environmental assessment process which seeks to prevent or mitigate adverse environmental impacts of developments. CEAA only applies to projects involving a federal interest or approval. The triggers which may invoke the requirements of CEAA include a project that involves one or more of the following: a federal proponent, federal funding, federal lands, or a federal approval. The assessment process under CEAA must be initiated by the federal agency which provides the federal trigger and may involve a screening report or a more detailed comprehensive study report. The latter process specifically lists oil sands projects among those developments that are covered, provided a federal trigger exists.[10]

The most common triggers for CEAA have been either or both of the requirements for approvals under the FA and the NWPA. Although the MBCA has become prominent as a federal jurisdiction because of the Syncrude oiled ducks prosecution,[11] the MBCA does not provide a relevant federal approval requirement which could trigger CEAA.

The Canadian Environmental Assessment Agency which administers CEAA has had a cooperative agreement with Alberta since 1999, which was renewed in 2005, for developments that would be required to undergo an environmental impact assessment under both federal and provincial requirements to achieve the mutual objectives by performing a joint environmental assessment: [12]

"*To ensure that the environmental effects of proposed projects are carefully considered before decisions are taken by governments.*

- *To achieve greater efficiency and the most effective use of public and private resources, where assessment processes involving both parties are required by law, through a single environmental assessment and review process for each proposed project.*
- *To establish accountability and predictability by delineating the roles and responsibilities of the federal and provincial governments*."

Under the cooperative agreement, neither government delegates any decision-making authority to the other. Each government agency will make a determination whether a public hearing is necessary and if both agree on the need for a hearing, they will cooperate in a joint review panel and public hearing. If

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[10] SOR/94-638 Comprehensive Study List Regulations. "***11.*** *The proposed construction, decommissioning or abandonment of*
(a) [Repealed, SOR/2003-282, s. 2]
(b) a heavy oil or oil sands processing facility with an oil production capacity of more than 10 000 m^3/d; or
(c) an oil sands mine with a bitumen production capacity of more than 10 000 m^3/d."

[11] In April 2008, over 1,600 ducks (initially estimated as 500) became contaminated with oil and died on the Syncrude Aurora tailings pond leading to prosecution launched in February 2009 by Alberta under the Environmental Protection and Enhancement Act and by Canada under the Migratory Birds Convention Act.
www.theglobeandmail.com/report-on-business/article971947.ece accessed April 16, 2010.

[12] Canada-Alberta Agreement on Environmental Assessment Cooperation (2005).
www.ceaa.gc.ca/default.asp?lang=En&n=F93B8BF6-1 accessed April 15, 2010.

only one government agency determines that a public hearing is necessary, the other government agency agrees to cooperate in support of that hearing. Despite the cooperative agreement to a joint assessment process under the appropriate circumstances, upon completion of the assessment process each government agency proceeds to its own regulatory approval process unfettered by the other government.

Other Relevant Federal Legislation. In specific circumstances other federal legislation including the Canadian Environmental Protection Act, the Transportation of Dangerous Goods Act, and the National Energy Board Act may have some role regarding oil sands developments.

There are also a number of potentially relevant issues regarding Aboriginal interests including the Indian Act and the Indian Oil and Gas Act. The Supreme Court in 2004 reconfirmed that the federal and provincial governments have a duty to consult in a meaningful way with Aboriginal Peoples concerning developments that may impact established aboriginal and treaty rights, as well for any titles or rights that have been asserted by Aboriginal Peoples even if they not been defined or established.

The Canadian Environmental Protection Act (CEPA). This Act is the primary federal legislation to establish the federal framework for protecting the environment and human health from the impact of pollutants released to the environment.[13] CEPA has provisions authorizing the production of objectives, guidelines or codes of practice governing the release of specified substances to the environment and, where a substance has been declared to be "toxic" according to CEPA, may make regulations limiting the amount of a toxic substance that may be released. The environmental impact assessment (EIA) requirements for oil sands projects which are described later would expect disclosure by the developer of any CEPA toxic substances which may be involved in the project. To date, the application of CEPA to oil sands developments has not involved any explicit authorization or approval under CEPA, but oil sands developments have been required to report their emissions of specified pollutants to the National Pollutant Release Inventory (NPRI) which is authorized under CEPA.[14] Substances subject to NPRI reporting must be disclosed in the EIA for an oil sands development. The NPRI provides a convenient basis for comparing emissions from various Canadian industrial sources on an annual total release basis. There is also potential for the federal government to exercise its jurisdiction with respect to trans-boundary pollution, a power that would be particularly applicable to greenhouse gas emissions for example, but to date, the federal government has not chosen to pursue this possibility.

The Transportation of Dangerous Goods Act (TDGA). This Act establishes standards for public safety with regard to the transportation of dangerous goods, including oil and gas products but it does not apply to their transport in pipelines. Thus, some regulatory scope governing dangerous goods transport in oil sands operations may appear and any substances regulated under TDGA must be disclosed in an

[13] R.S.C. chap. C-33. "*An Act respecting pollution prevention and the protection of the environment and human health in order to contribute to sustainable development*."

[14] R.S.C. chap. C-33. "***48.*** *The Minister shall establish a national inventory of releases of pollutants using the information collected under section 46 and any other information to which the Minister has access, and may use any information to which the Minister has access to establish any other inventory of information*."

EIA, but the Alberta Dangerous Goods Transportation and Handling Act[15] provides for provincial regulation of these matters, including administering federal requirements.

The National Energy Board Act (NEBA). This Act governs the authorization of interprovincial or international export of energy which clearly covers the interests of the oil sands industry which is primarily engaged in the export of synthetic crude oil or bitumen extracted from the oil sands. The National Energy Board (NEB) is primarily concerned with energy conservation, market and economic aspects but also considers environmental aspects of pipelines (e.g., the Gateway pipeline proposal which will undergo a joint review by the NEB and CEAA[16]).

Fort McKay First Nation Oil Sands Regulations. "The members of Fort McKay First Nation (in Alberta) voted in September 2003 to accept a Treaty Land Entitlement settlement agreement and to designate lands containing mineable crude bitumen (oil sands) to be added to reserve for leasing for the purpose of exploiting the oil sands. The designation states that the lands can only be leased for development of the oil sands if 'a regulatory regime is established...sufficient to protect the interests of the First Nation, its members, the environment, and Her Majesty."

The federal government currently does not have a regulatory regime specifically designed to address oil sands mining activities. The Province of Alberta has an extensive, comprehensive regulatory regime for oil sands mining, but much of this regime does not apply on reserve lands. Federal regulations are needed in order to create regulatory certainty and to effectively manage environmental, health and safety, and other related impacts of the proposed oil sands mining project, and thereby enable the leasing of the lands for oil sands development."[17]

[15] R.S.A. 2000 Chapter D-4
[16] http://www.northerngateway.ca/public-review/regulatory-process
[17] 2007-05-02 *Canada Gazette* Part II, Vol. 141, No. 9: 646-662.

Provincial Regulatory Authority

Sale of Mineral Rights.

The Oil Sands deposits in Alberta are primarily located on Crown land which means that the mineral rights to the bitumen reside with the provincial Crown.[18] Any organization seeking to extract bitumen from these deposits must obtain a permit or lease from the provincial government.

In order to acquire oil sands rights, a corporation must be registered to conduct business in the Province of Alberta and comply with Section 23 of the Mines and Minerals Act (MMA).[19] Crown-owned oil sands rights are disposed by means of agreements under Section 16 of the MMA.[20] Oil sands rights include the right to "*drill for, win, work, recover and remove*" oil sands that are owned by the Crown. There are currently two types of Oil Sands agreements:

1. Permits that are issued for a term of 5 years.
2. Leases that are issued for a term of 15 years.

Oil Sands rights can be acquired:

1. By way of a registered transfer (i.e., to buy into an existing agreement).
2. By way of public sale.

Access to Public Lands.

There are two aspects of gaining approval for access to public lands: exploration and operations. Having oil sands rights is not a prerequisite to seeking access for exploration purposes but clearly the oil sands rights have to be acquired before access can be granted for operations.

The regulatory process for gaining exploration approval for oil sands in Alberta is managed by Alberta Sustainable Resource Development (SRD) under the Oil Sands Exploration Program.[21] This program references the Code of Practice for Exploration Operations[22] which includes operating guidelines and application information requirements. This code is under the Environmental Protection and Enhancement Act (EPEA) administered by Alberta Environment (AENV). The exploration approval is

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[18] "*The oil sands mineral rights in approximately 97 percent of Alberta's 140,200 square kilometers of oil sands area are owned by the provincial Crown… The remaining 3 percent of the oil sands mineral rights in the province are held by the federal Crown within Indian reserves, by successors in title to the Hudson's Bay Company, by the national railway companies and by the descendents of original homesteaders through rights granted by the federal Crown before 1887. These rights are referred to as 'freehold rights'.*" Alberta's Oil Sands 2008 www.energy.alberta.ca/OilSands/960.asp accessed April 12, 2010.

[19] R.S.A. 2000. Chapter M-17

[20] "*As of June 2009 there are approximately 5,012 oil sands (mineral rights) agreements with the Province* [of Alberta] *totaling approximately 82,542 square kilometres. Close to 41 percent of possible oil sands areas are still available for leasing*." Alberta's Oil Sands 2008 www.energy.alberta.ca/OilSands/960.asp , accessed April 12, 2010.

[21] Government of Alberta. 2010. Alberta Provincial Decision Processes Related to Integrated Land Management. www.srd.alberta.ca/ManagingPrograms/IntegratedLandManagement/documents/AlbertaProvincialDecisionProcessesRelatedtoIntegratedLandManagement-Jan10.pdf , accessed April 12, 2010.

[22] Alberta Environment. 2005. Code of Practice for Exploration Operations. September. www.qp.alberta.ca/documents/codes/EXPLORE.pdf , accessed April 13, 2010.

issued under the Public Lands Act (PLA) and sets administrative and operating conditions initially for a one year term, with options for time extensions upon application. Other guidance regarding how SRD manages public lands is provided in the Public Lands Operational Handbook.[23] These documents outline in general terms the factors that may be taken into consideration in assessing and approving an application for access to public lands for oil sands exploration but they do not provide explicit criteria for denying exploration approval, justifying an overall impression that applications for exploration approvals will be approved provided that information requirements are fulfilled and that appropriate mitigative measures are proposed (Vavlianos 2007, p. 22).

Granting surface rights for oil sands operations is administered by SRD under the PLA and the Surface Rights Act (SRA). An oil sands development on public lands will require approval under a mineral surface lease (MSL)[24], and may require a license of occupation (LOC)[25] or a pipeline agreement (PLA)[26]. An MSL may authorize access roads, thereby eliminating the need for a separate LOC (Vavlianos 2007, p. 24). These approvals will not be issued until the project receives overall authorization from the Energy Resources Conservation Board (ERCB), the major regulatory approval process to be outlined below. Likewise, in the oil sands regions, most of the public lands are subject to Forestry Management Agreements (FMA), administered by SRD, and consent from the FMA holder is required. In practice, if the approvals are issued by SRD, the forestry company will be directed to harvest the timber before the oil sands project is implemented. The PLA provides ample authority to the SRD Minister to specify terms and conditions for these approvals, including cancelation for non-compliance with terms and conditions.

The SRA prohibits an operator from entering lands to exercise mineral rights without obtaining the consent of the owner or occupier of the land[27] and it creates the Surface Rights Board (SRB) which may issue a right of entry order if the owner or occupier denies access. However, in practice with less than 3% of oil sands reserves located on other than provincial crown land, and much of that being

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[23] Alberta Sustainable Resource Development. 2004. Public Lands Operational Handbook. December. www.srd.alberta.ca/MapsFormsPublications/Publications/documents/PublicLandsOperationalHandbook-Dec2004.pdf , accessed April 13, 2010.

[24] "*Mineral surface leases issued to mineral producers grant exclusive surface rights for surface mining and quarries, wellsites for oil and gas extraction, heavy oil/in situ oil sands and battery sites, or for other purposes incidental to the recovery and production of minerals. The maximum term is 25 years and is renewable*." p.38 Government of Alberta. 2010. Alberta Provincial Decision Processes Related to Integrated Land Management. www.srd.alberta.ca/ManagingPrograms/IntegratedLandManagement/documents/AlbertaProvincialDecisionProcessesRelatedtoIntegratedLandManagement-Jan10.pdf , accessed April 12, 2010.

[25] Ibid. at p.38. "*Licences of Occupation grant the right to occupy public lands for an approved purpose, and may be subject to other dispositions granted for the same area. They are issued primarily for access roads, but may also be issued for other purposes (e.g. water intake/outfall sites, pier sites, airstrips, reservoirs). The LOC does not grant any other right to the land. The term of the licence varies depending on the purpose*."

[26] Ibid. at p.39. "*Pipeline agreements authorize construction of a pipeline or flowline within the right-of-way and construction of right-of-way installations incidental to the pipeline (e.g. valve, valve box, connection, foundation). The agreement may remain in effect for as long as required*."

[27] R.S.A. 2000, Chapter S-24, "***12(1)*** *No operator has a right of entry in respect of the surface of any land*
(a) for the removal of minerals contained in or underlying the surface of that land or for or incidental to any mining or drilling operations,…. until the operator has obtained the consent of the owner and the occupant of the surface of the land or has become entitled to right of entry by reason of an order of the Board pursuant to this Act."

located on federal crown land in right of Indian reservations, there is no significant role for the SRB in oil sands development.

Project Review (Public Interest Determination and Environmental Assessment)

The Energy Resources Conservation Board (ERCB)[28] has been granted exclusive jurisdiction in Alberta over oil sands development and conservation by the Oil Sands Conservation Act (OSCA).[29] Under this jurisdiction construction or operation of any development to recover bitumen from oil sands is prohibited without the approval of the ERCB.[30] An oil sands developer may make a preliminary application for a project that the ERCB reviews and determines whether the proponent can proceed to a full application for approval under the OSCA in accordance with ERCB Directive 23 but this process is no longer commonly used.[31]

Normally, the Application must include an EIA in accordance with the specified activities subject to mandatory environmental assessment according to regulations under the EPEA or any project that the responsible Director of AENV decides requires an EIA. Mandatory projects include oil sands mines and / or any oil sands, heavy oil extraction, upgrading or processing plant producing more than 2000 m^3 of crude bitumen per day.[32]

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[28] The Oil and Gas Conservation Board, a pioneering energy regulatory authority which became a model for oil and gas industry regulation in the 1960s, was renamed the Energy Resources Conservation Board (ERCB) in 1970. The ERCB, already the largest and most powerful regulatory board in Alberta was merged with the Public Utilities Board by the newly elected Klein government to become the Energy and Utilities Board (EUB) in 1994. The EUB was once again split into the ERCB and the Alberta Utilities Commission (AUC) in 2008 following a major public controversy over the EUB hiring a private investigator to participate in a public group which opposed an electricity transmission line that is now being considered by the AUC. In this document, ERCB will be used to refer to anything performed or published by the EUB between 1994 and 2008.

[29] R.S.A. 2000 Chapter O-7, "***5.*** *Except as otherwise provided in this or any other Act, the Board has exclusive jurisdiction to examine, inquire into, hear and determine all matters or questions arising under this Act*."

[30] R.S.A. 2000 Chapter O-7, "***10(1)*** *No person shall*

(a) construct facilities for a scheme or operation, or

(b) commence or continue a scheme or operation for the recovery of oil sands or crude bitumen, unless the Board, on application, has granted an approval in respect of the scheme or operation.

(2) *The Board shall, on receiving an application referred to in subsection (1), make any investigations or inquiries and hold any hearings that it considers necessary or desirable in connection with the application.*

(3) *The Board may, with respect to an application referred to in subsection (1),*

(a) if in its opinion it is in the public interest to do so, and with the prior authorization of the Lieutenant Governor in Council, grant an approval on any terms and conditions that the Board considers appropriate,

(b) refuse to grant an approval,

(c) defer consideration of the application on any terms and conditions that the Board may prescribe, or

(d) make any other disposition of the application that the Board considers appropriate."

[31] ERCB Directive 23 Guidelines Respecting an Application for a Commercial Crude Bitumen Recovery and Upgrading Project. http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_308_265_0_43/http%3B/ercbContent/publishedcontent/publish/ercb_home/industry_zone/rules__regulations__requirements/directives/directive023.aspx . accessed April 16, 2010.

[32] A.R. 111/1993 - Environmental Assessment (Mandatory and Exempted Activities) Regulation

"*Schedule 1 Mandatory Activities*

The construction, operation or reclamation of

(i) an oil sands mine;

(j) a commercial oil sands, heavy oil extraction, upgrading or processing plant producing more than 2000 cubic metres of crude bitumen or its derivatives per day"

In unusual cases if there is any question of the need for an environmental impact assessment for a project that is not subject to a mandatory assessment, the EIA process requires the proponent to submit a Project Summary Table to the Director to allow a determination of the need for an EIA.[33] If the Director determines that an EIA is not required (only for discretionary projects), the proponent can apply for the necessary environmental approvals. Alternatively, the Director may determine that more information is required which will be accomplished by the proponent preparing a screening report. This requirement also includes a disclosure document to notify the public, providing a minimum of a 30 day public comment period, of a project that the AENV Director will screen for the purposes of determining the need for an EIA. When the Director has made this determination, the screening report is made public and the proponent is advised whether an EIA report is required.

Proponents for projects that require an EIA must prepare a Proposed Terms of Reference (PTOR) which must be made public in addition to being submitted to the Director. Detailed guidance on EIA content is provided that is based on previous EIAs and feedback on them.[34] This EIA documentation includes a specific template for oil sands developments. Based on this proposal and submissions from the public and other agencies (including federal agencies where applicable) the Director prepares the Final Terms of Reference (FTOR) that determines the scope of the EIA.

When completed, the EIA is submitted to the responsible Director of AENV who coordinates a technical review by provincial and federal government agencies to determine if the EIA satisfies the FTOR. Any uncertainties or deficiencies identified in the EIA review will be directed to the proponent as Supplemental Information Requests (SIR). When the review team is satisfied that the EIA clearly describes the potential impacts of the proposed project as required in the FTOR, they advise the responsible Director of AENV accordingly. When the AENV Director determines that the EIA is complete the EIA is acknowledged to be complete and it is referred to the ERCB where it becomes part of the proponent's application for approval under the OSCA in accordance with ERCB Directive 23.

The public must be notified about the nature of a proposed oil sands project at various stages of the EIA process. If the project proceeds to an application for approval by the ERCB, that board must determine whether there is a need to hold a public hearing, including provisions under ERCB Directive 29 for the public to make submissions to the ERCB regarding the need for a public hearing.[35] Major oil

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[33] Environmental Assessment Program, EA Guide 2008-1, Alberta's Environmental Assessment Process Updated February 2010. http://environment.gov.ab.ca/info/library/6964.pdf accessed April 15, 2010.

[34] Environmental Assessment Program, Standardized Terms of Reference – Updated October 2009. http://environment.gov.ab.ca/info/library/8126.pdf accessed April 17, 2009.

[35] ERCB Directive 29. Energy and Utility Development Applications and the Hearing Process. January 2003.

"***6.*** *Triggering the Hearing Process*

If you are a person, organization, or company who shows through a written submission that your rights may be directly and adversely affected if the Board approves a proposed energy or utility development and you have been unable to resolve outstanding concerns with the company through sincere negotiations or ADR, you may trigger a public hearing. The party seeking to trigger a hearing must provide information to the Board to show that it has rights that may be directly and adversely affected by the Board's decision on the application. The Board does not deal with disputes related to surface rights agreements.

The EUB examines each submission on a case-by-case basis to determine the potential impacts on the person(s) in question and takes into account the following factors:

sands mine developments typically require a public hearing before the ERCB and it may authorize funding by the applicant of public participants at a hearing that the ERCB judges to be local interveners.[36] In those cases which the federal government has declared a need for an EIA under CEAA, and also determines a need for a hearing, a joint federal-provincial review panel will be called under the Canada – Alberta cooperative agreement.[37] This agreement specifies the process for determining the composition of the joint review panel and the process for making the appointments to the joint review panel. Typically, because the majority of relevant regulatory jurisdiction resides with the province, joint review panels of major oil sands projects consist of two provincially appointed members, including the Chair, and one federally appointed member.

The ERCB is charged with making an overall "*public interest*" determination regarding any application for oil sands development.[38] Considerations bearing on the "*public interest*" determination are further elaborated in the purpose section of the OSCA.[39] If the ERCB decides to recommend the

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• Does the proposed project have the potential to affect safety or economic or property rights? Examples of such impacts include negative effects from contaminants in water, air, or soil or from noise; negative interference with livelihood or commercial activity on the land; damage to property; and concerns for the safety of persons or animals.
• Are you affected in a different way or to a greater degree than members of the general public?
• Are you able to show a reasonable and direct connection between the activity complained of and the rights or interests you believe to be affected?

If the Board determines that you may be directly and adversely affected by its decision, it considers that you have standing to appear at the hearing. Once a hearing has been triggered, other interested parties, including parties who may not have standing, may participate in the hearing. Parties who do not have standing but participate in the hearing will not qualify for costs. Note that if the party that triggers the hearing withdraws from the hearing and no other party has standing, the Board may grant the application and cancel the hearing."

[36] ERCB Directive 29. Energy and Utility Development Applications and the Hearing Process. January 2003
"***11.*** *Costs*
If you participate as an intervener in a hearing, you may make a request to the Board that the costs you have incurred with respect to your intervention be paid by the applicant. The Board then determines whether you are eligible to have your costs paid and what costs are eligible.

Only those persons determined by the Board to be 'local interveners' are eligible to recover costs incurred for the preparation and presentation of an intervention at a public hearing before the Board. Section 28(1) of the Energy Resources Conservation Act defines the term 'local intervener' as follows:

> ***28(1)*** *In this section, "local intervener' means a person or a group or association of persons who, in the opinion of the Board,*
> *(a) has an interest in, or*
> *(b) is in actual occupation of or is entitled to occupy*
> *land that is or may be directly and adversely affected by a decision of the Board in or as a result of a proceeding before it, but, unless otherwise authorized by the Board, does not include a person or group or association of persons whose business includes the trading in or transportation or recovery of any energy resource."*

[37] Canada-Alberta Agreement on Environmental Assessment Cooperation (2005). www.ceaa.gc.ca/default.asp?lang=En&n=F93B8BF6-1 accessed April 15, 2010.

[38] R.S.A. 2000 Chap E-10 "***3.*** *Where by any other enactment the Board is charged with the conduct of a hearing, inquiry or other investigation in respect of a proposed energy resource project, it shall, in addition to any other matters it may or must consider in conducting the hearing, inquiry or investigation, give consideration to whether the project is in the public interest, having regard to the social and economic effects of the project and the effects of the project on the environment*."

[39] R.S.A. 2000 Chap O-7 "***3.*** *The purposes of this Act are:*

> *(a) to effect conservation and prevent waste of the oil sands resources of Alberta,*
> *(b) to ensure orderly, efficient and economical development in the public interest of the oil sands resources of Alberta,*
> *(c) to provide for the appraisal of Alberta's oil sands resources,*
> *(d) to provide for appraisals of oil sands, crude bitumen, derivatives of crude bitumen and oil sands product requirements in Alberta and in markets outside Alberta,*

application, subject to whatever conditions it deems appropriate, that recommendation is made through the Minister of Energy to the Alberta Cabinet which holds the ultimate authority to approve a project, but only if it is recommended to Cabinet by the ERCB. In addition to its project approval mandate, the ERCB also functions as a regulator of oil sands operating and abandonment procedures.

The ERCB is also charged with regulating virtually every aspect of the planning and operation and of an oil sands operation (mining, in situ and bitumen operations), including most factors related to residuals and waste management.[40] There is also considerable regulatory authority governing oil sands operations vested in AENV and SRD, so the respective responsibilities of the regulators are covered by a Memorandum of Understanding[41] among these agencies.

The details of the split and shared responsibilities are set out in Table A2.1.

(e) to assist the Government in controlling pollution in the development and production of the oil sands resources of Alberta,
(f) to provide for the recording and for the timely and useful dissemination of information regarding the oil sands resources of Alberta, and
(g) to ensure the observance, in the public interest, of safe and efficient practices in the exploration for and the recovery, storing, processing and transporting of oil sands, discard, crude bitumen, derivatives of crude bitumen and oil sands products."

[40] Alberta Regulation 76/1988 Oil Sands Conservation Regulation.

[41] *Memorandum of Understanding between the Alberta Energy and Utilities Board [*now Energy Resources Conservation Board*] and Alberta Environmental Protection [*now Alberta Environment and Alberta Sustainable Resource Development*] with respect to Oil Sands Developments, April 1996.* www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_308_265_0_43/http%3B/ercbContent/publishedcontent/publish/ercb_home/industry_zone/rules__regulations__requirements/information_letters__interim_directives/informational_letters/il96_07.aspx , accessed April 18, 2010.

Table A3.1 Distribution of Regulatory Responsibilities Among the ERCB, AENV and SRD
Memorandum of Understanding between the Alberta Energy and Utilities Board [*now ERCB*] and Alberta Environmental Protection [*now AENV and SRD*] with respect to Oil Sands Developments, April 1996.

2. HARMONIZATION OF EUB AND AEP ACTIVITIES

Energy resource management and environmental protection issues are interrelated. Legislation requires that both the EUB and AEP consider the environmental effects of development proposals requiring their approval. Consequently, there is a need to ensure, without fettering the discretion of any statutory decision maker, that:

- the approval and regulatory activities of the EUB and AEP are harmonized, and
- the decisions of the EUB and AEP are consistent.

To achieve this, the EUB and AEP have agreed to the roles and responsibilities set out in the pages that follow.

2.1 EUB Responsibilities

In carrying out its mandate regarding the approval of oil sands developments, the EUB has primary decision making authority regarding:

- the determination of whether a project is in the public interest (having regard for the social, economic, and environmental effects of the project),
- the conservation of energy resources including the resource recovery technology,
- the location of the development and layout of facilities,
- the design of produced water recycle systems for in situ developments,
- the storage and disposal of oilfield wastes resulting from in situ developments, and
- the sub-surface disposal of produced fluids and solids.

In carrying out its mandate regarding the regulation of operations at oil sands developments, the EUB has primary responsibility for:

- ensuring the stability of overburden dumps and mine pit walls,
- specifying requirements for the abandonment of wells and removal of surface facilities,
- specifying and monitoring the recovery efficiencies for oil sands, bitumen, sulphur, and other products and by-products,
- specifying and monitoring the efficiency of produced water recycle systems,
- specifying the requirements for the management of oilfield waste produced at in situ developments,
- specifying the analytical equipment and methods for measuring the volume, composition, and conditions of all process streams necessary for the determination of material and energy balances, and
- specifying the content and frequency of production and operations reports to the EUB.

2.2 AEP (AENV) Responsibilities

In carrying out its mandate under the EPEA, WRA (now the Water Act), and PLA regarding the approval of oil sands developments, AEP has primary decision making authority regarding:

- the designation of projects subject to the Environmental Impact Assessment (EIA) process and the management of that process,
- the conservation and reclamation requirements for all surface disturbances,
- the pollution prevention, pollution control, and waste management systems,
- the allocation of water resources,
- the use and protection of potable water systems, and
- access to public lands and the management of the associated land use planning process.

Table A3.1 Distribution of Regulatory Responsibilities Among the ERCB, AENV and SRD
Memorandum of Understanding between the Alberta Energy and Utilities Board [*now ERCB*] and Alberta Environmental Protection [*now AENV and SRD*] with respect to Oil Sands Developments, April 1996.

continued

In carrying out its mandate regarding the regulation of operations at oil sands developments, AEP has the primary responsibility for:

- specifying the acceptable levels of emissions to air, water, and land based on appropriate pollution control technology,
- specifying the ambient environmental quality in the zone of influence of emissions,
- specifying the efficiency and monitoring the performance of pollution control and waste management systems,
- specifying the analytical equipment, methods and frequency for measuring emissions,
- specifying the required ambient and environmental effects monitoring,
- specifying monitoring and reporting of water use, and
- specifying environmental reporting frequencies and formats.

In carrying out its mandate regarding the enforcement of the EPEA legislation as it applies to oil sands developments, AEP will:

- monitor compliance with environmental requirements,
- review alleged non-compliance reports submitted by the operators,
- investigate incidents involving public complaints and industry non-compliance,
- conduct compliance reviews on investigation files that have sufficient evidence of contravention, and
- determine appropriate enforcement response and carry out enforcement actions.

2.3 Shared Responsibilities

2.3.1 Approval of Oil Sands Developments

Applications

The EUB and AEP are committed to making timely, consistent decisions and to coordinating their respective application processing activities and schedules to achieve a comprehensive and streamlined regulatory process. Historically, the timing of applications to the EUB and AEP has been such that an approval by the EUB (with the authorization of the Lieutenant Governor in Council) typically preceded approvals by AEP. Through the EUB's referral process, AEP contributes to the review of applications to the EUB and frequently participates in public hearings conducted by the EUB. Before making a decision under the EPEA on a related matter, an AEP director (as a statutory decision maker) must consider any written decision by the EUB and may consider any information that was placed before the EUB in relation to that decision. Accordingly, the EUB and AEP will coordinate their respective application processing activities and schedules in the manner described below.

For major developments (i.e. new commercial projects or significant amendments to commercial projects) the use of an integrated approach is desirable given that applications are required under both the OSCA and EPEA. The integrated approach that will be followed for these applications is outlined in the generalized process diagram shown in the attached figure.

Applications to the EUB and AEP for a major oil sands development will be filed concurrently with each agency. When appropriate, a single, integrated document will be prepared which includes all the information required under both the OSCA and EPEA (including the EIA). Where applicable, the application will also include information required under the WRA [now Water Act]. Applications for access to public land, required under the PLA, will usually be made to AEP [now SRD] separately. Although the EUB and AEP have jointly developed guidelines on application content, additional discussion with both agencies is encouraged to clarify content and help ensure that all required information is contained in the initial filing.

Table A3.1 Distribution of Regulatory Responsibilities Among the ERCB, AENV and SRD
Memorandum of Understanding between the Alberta Energy and Utilities Board [*now ERCB*] and Alberta Environmental Protection [*now AENV and SRD*] with respect to Oil Sands Developments, April 1996.

continued

Upon receipt of an application, the EUB and AEP will appoint lead coordinators who will be available to consult with the applicant and other stakeholders regarding the application process. The EUB and AEP, through these coordinators and in consultation with the applicant, will assume responsibility for developing a schedule with deadlines for information filing and the deficiency process. The coordinators will monitor the application process relative to this schedule and will advise all parties of any potential delays and associated schedule adjustments.

In situations where AEP staff have significant environmental concerns regarding a development proposal (or a fundamental aspect of a proposal) and are not likely to issue an approval given those concerns, AEP will inform the EUB and the applicant of those concerns. This will allow the applicant an early opportunity to clarify or revise the application.

All applications require consultation between the applicant and affected stakeholders. Both agencies encourage that stakeholder consultation begin well before the filing of applications. Stakeholder consultation is the responsibility of the applicant and may include meetings with local groups and organizations and conducting open houses. In situations where they may be of assistance, EUB and AEP staff will participate in the stakeholder consultation process subject to staff availability and provided that the applicant continues to take the lead role.

Publication of a notice advising that an application has been filed is a requirement under the EPEA. The EUB may also, at its discretion, issue a "Notice of Filing" and/or a "Notice for Objection". Where there is a decision to hold a public hearing before an EUB panel, a "Notice of Hearing" will be issued. The placement of a notice under the EPEA and an EUB "Notice of Filing" will usually occur shortly after the filing of an application (i.e. once it has been determined to be sufficiently complete to commence a review under the EPEA) and will generally take the form of a joint notice (in accordance with the EUB/AEP MOU on joint notice).

An EUB "Notice for Objection" is not normally issued until all information has been filed by an applicant and the application has been judged sufficiently complete for adjudication (i.e. following any deficiency process). Such notice may not be required in cases where the EUB is satisfied that:

- the public is not materially affected by the project,
- public objection to the application is unlikely, or
- the concerns of all potential interveners have been resolved.

In the event the need for a public hearing appears likely, the EUB will consider holding a pre-hearing meeting to support an efficient and procedurally fair approval process. Items that could be addressed at a pre-hearing meeting may include one or more of the following:

- identification of interested parties,
- local intervener funding (eligibility and amount),
- scope of issues to be considered at the hearing,
- consideration of how issues are best addressed at the hearing and by whom, and
- consideration of a timetable for the filing of interventions and evidence and the commencement of the hearing.

Should the EUB decide that the application is in the public interest, authorization of the Lieutenant Governor in Council is required to grant the approval. It is therefore most important that the EUB has all the relevant issues and information placed before it. The integration of the EUB and AEP regulatory approval processes will help to ensure that this takes place.

Table A3.1 Distribution of Regulatory Responsibilities Among the ERCB, AENV and SRD
Memorandum of Understanding between the Alberta Energy and Utilities Board [*now ERCB*] and Alberta Environmental Protection [*now AENV and SRD*] with respect to Oil Sands Developments, April 1996.

completed

In situations where AEP staff have significant concerns regarding an application to the EUB (and the EIA) or a fundamental aspect of an application, but are prepared to recommend approval pending resolution of its concerns, they will inform the EUB and the applicant in writing when the concerns are identified. In the event of an EUB hearing, AEP may decide to take an active role in the proceedings, the nature of which will be determined having regard for the environmental issues identified. If there are significant issues of interest to AEP, its role could include:

- cross-examination only,
- cross-examination and argument, or
- presenting evidence, cross-examination, and argument.

In the latter two cases, AEP will provide argument as to its position on the matter. In cases where AEP has evidence that it believes the EUB should have when making a decision, AEP will provide a panel to present the evidence at the hearing. This procedure will make certain that the EUB has all the relevant views and data before it and will afford the applicant and other interested parties an opportunity to speak to all of the evidence used by an EUB panel in arriving at its decision.

As appropriate, AEP will also present information (through its witness panel) regarding the applications for EPEA and WRA [now Water Act] approvals. This information will clarify, for the EUB hearing panel, AEP's statutory requirements and any issues that arise in the EPEA/WRA applications.

This enhanced role of AEP at the hearing (i.e. through its presentation of evidence on environmental issues and AEP statutory issues of interest to the EUB) should assist the EUB and help ensure that there is a common understanding of the information before the EUB. This should also ensure consistency between the EUB and AEP decisions.

For less complex developments, and particularly those projects where the need for approval by either the EUB or AEP is unclear (such as some types of plant modifications), early communication by the proponent with both agencies is essential to establish approval requirements and thus avoid unnecessary delays in the application process. If it is established that an application under both the OSCA and the EPEA is required, the integrated approach, or an appropriate modification of it, will be followed. In such cases, the scope, content and detail of environmental requirements (such as the need for an EIA), and other technical information required for the applications will be jointly determined through a consultative process involving the proponent, EUB and AEP.

In addition, there are a number of other matters of jurisdiction between the ERCB, AENV and SRD which are covered by the MOU.

AENV has considerable regulatory authority to develop site specific EPEA and WA approvals that are required before an oil sands developer can operate. These are issued for up to 10 years under EPEA to govern a large number of very specific issues.[42] EPEA also includes a provision that approvals issued under EPEA and WA may be subject to appeal to the Environmental Appeals Board by the approval holder or by parties who are directly affected by the AENV decision to issue the approval. This right of appeal is limited for oil sands development by EPEA Section 95(5)(b)[43] which requires the Board to

[42] A major oil sands operating approval under EPEA is typically 50 to more than a hundred pages and covers issues such as: record keeping, analytical requirements, construction, monitoring equipment, land conservation, process units, wastewater management, potable water treatment, air emissions, monitoring of emissions and ambient air quality, biomonitoring, air quality and human exposure studies, reporting, continuous improvement, aquatic environmental effects monitoring, waste management, groundwater monitoring, financial security and reclamation.
[43] R.S.A. 2000 E-12 Environmental Protection and Enhancement Act Section 95(5)(b) the Board:

dismiss the appeal if the Board determines that all matters raised in the appeal have been adequately dealt with by the ERCB or all matters were covered in a joint review under CEAA.

Land reclamation is regulated by AENV under EPEA. ERCB has a responsibility to consider reclamation under its public interest mandate so ERCB works with AENV on reclamation issues with the proponent, and both agencies seek to make decisions that are consistent with each other.

Water use and developments affecting surface or groundwater involve the proponent making water license, permit and approval applications to AENV under the Water Act (WA).[44] AENV consults the ERCB about the volumes of water use requested by a proponent concerning whether the requests are appropriate to the development.

Tailings ponds and dam safety are jointly administered by the ERCB and AENV. The conceptual planning and preliminary engineering design of tailings ponds are performed by ERCB. Applications for construction of tailings ponds are governed under the WA and the Dam Safety Regulations.[45] AENV will lead the review of applications and issuing of tailings dam approvals. The ERCB and AENV coordinate approvals for abandonment of tailings ponds, but AENV sets the reclamations standards to be achieved for tailings ponds.

The interaction among agencies concerning tailings ponds is illustrated and further elaborated by the recent ERCB Directive governing tailings ponds.[46] This document reflects the need for greater

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"*(b) shall dismiss a notice of appeal if in the Board's opinion*
(i) the person submitting the notice of appeal received notice of or participated in or had the opportunity to participate in one or more hearings or reviews under Part 2 of the Agricultural Operation Practices Act, under the Natural Resources Conservation Board Act or any Act administered by the Energy Resources Conservation Board or the Alberta Utilities Commission at which all of the matters included in the notice of appeal were adequately dealt with, or
(ii) the Government has participated in a public review under the Canadian Environmental Assessment Act (Canada) in respect of all of the matters included in the notice of appeal."

[44] R.S.A. 2000 W-3 Water Act.

[45] A.R. 205 / 1998. Water Act Ministerial Regulation. Part 6. Dam and Canal Safety.

[46] ERCB Directive 074 - Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes, February 3, 2009
"***2.*** *Regulatory Framework for Tailings Management*
The ERCB regulates oil sands mining and processing operations, as well as discard from those operations, including tailings. Approvals for mines and processing plants are required by Sections 10 and 11 of the Oil Sands Conservation Act. Approval to commence, suspend, or abandon an oil sands site is required by Section 3 of the Oil Sands Conservation Regulation (OSCR). Approval for storage of discard generated by a mine or a plant is required by Sections 24 and 48 of the OSCR.

Alberta Environment (AENV) and Alberta Sustainable Resource Development (SRD) also regulate oil sands development. The ERCB (then known as the EUB), AENV (then known as Alberta Environmental Protection [AEP]) and SRD have a memorandum of understanding (MOU) outlining each agency's responsibilities and how they work together. The MOU addresses tailings ponds and other aspects of mineable oil sands management, including water use and reclamation.

AENV and SRD have primary responsibility for managing the environment, including pollution prevention and control, water allocation, use and protection of potable water, conservation and reclamation planning, and the evaluation of air, water, and land for environmental performance reporting. The ERCB, in its decisions on schemes, must approve the proposed reclamation plan and must be satisfied with water use and disposal. More specifically, Section 49 of the OSCR requires operators to minimize the use of fresh make-up water and the disposal of waste water, as well as to maximize the recycling of produced water.

The MOU recognizes the ERCB as the lead regulator for approving the need, location, design, and performance of discard sites. The MOU also recognizes the role and need for ERCB input to the broader process for establishing reclamation criteria that are clear and meet the objectives of the Government of Alberta."

attention by oil sands development operators to meeting their commitments for managing and reclaiming tailings ponds.

APPENDIX A4 EXAMPLE MONITORING REQUIREMENTS OF EPEA APPROVALS

The following provides examples of water-related requirements attached to EPEA approvals.

Surface Mine Approval, example of Suncor Energy Inc. Oil Sands Processing Plant and Mine (effective date: Aug 13, 2007). Other approvals looks quite similar.

The approval requires the holder to develop a proposal for a Groundwater Monitoring Program for the North Steepbank Mine Extension and the Voyageur Upgrader. Among the items required are

- Local groundwater monitoring network
- Hydrogeology of the plant (including maps, flow directions and gradients, hydraulic conductivity)
- Description of monitoring wells
- List of parameters to monitor + description of GW sampling strategy

A bi-annual (2-year) GW monitoring Program Summary Report must be submitted and must contain, among other

- General hydrogeologic characterization of the region within a 5 km radius from the plant
- Detailed hydrogeologic characterization of the plant
- Location of all SW and GW users (+ water use details) within 3km radius from plant
- Map of surface drainage
- Summary of water levels and interpretation of any change
- Interpretation of GW analytical results, including locations of any contamination, extent and sources of contamination, charts indicating temporal trends
- Description of : contaminated GW remediation techniques used, source elimination measures used, risk assessment and management studies

Approval also requires that holder participate in regional groundwater initiatives for the Athabasca Oil sands Region, including at least:

- Regional GW quality assessment studies
- Development and implementation of regional GW monitoring network
- Continuous monitoring of network
- Assessment of potential GW quality impacts

For tailings, requirement to submit a bi-annual update on environmental aspects of tailings research and development that include at a minimum

- Forest ecosystem research
    - Time required for tailing to consolidate to trafficable surface
    - Suitable capping materials and depth of reclamation materials required to cover tailings deposits
    - Stability of reclaimed tailings surfaces over time
    - Characterization of tailings release water and any required treatment
    - Movement of salts from tailings release water during deposition or seepage and impact on plant development due to uptake of organic compounds, heavy metals and salts from tailings water
    - Techniques to isolate tailings waters from terrestrial lands
    - Identification of local native vegetation species suitable for re-establishment on lands affected by tailings waters

    - Seepage of tailing release water in GW, including expected volumes of water entering the GW regimes, flow regimes of GW, impacts of affected GW and any proposed mitigation.
- Wetland ecosystem research
    - Chemical characterization and rate of pore water release and surface runoff from tailings deposits
    - Fate (and degradation rates) of potentially toxic contaminants in tailings release waters
    - Impact of release waters on aquatic communities
    - Identify local native wetland vegetation species suitable to inhabit the tailings wetlands
    - Seepage of tailings (and placed coversoil, subsoil, overburden) release water into GW or SW, including
        - Expected volumes of water release into GW or SW runoff
        - Flow regimes for GW and SW
        - Impacts to GW or SW and subsequent downgradient or downstream effects
        - Any propose mitigation
    - Validation of expected scenarios with field-collected data describing hydrology and water quality of tailings seepage within receiving environment

Wetlands : holder shall continue to participate in activities of various wetland research initiatives; study on reclamation techniques to examine viability of bog/fen creation for portion of final landscape, undertake construction of pilot wetlands (and watershed). Holder should submit a 5-year plan for wetland research that includes

- Plan and schedule to build pilot wetlands (including bog/fen wetland)
- Monitoring of pilot wetland and expected criteria and performance measures
- Demonstrate understanding of hydrology of wetlands and their watersheds
- Vegetation establishment measures
- Planting material management

Mine dump : holder must develop a proposal for Groundwater Monitoring Program, similar to that for the plant

<u>In Situ approvals</u> – Examples based on 1) - Northstar Energy Corporation : Dover enhanced recovery in situ heavy oil processing plant, 2) - Petro-Canada : MacKay River enhanced in situ oil sands, 3)- Suncor Energy : Firebag Enhanced Recovery.

Requirements are generally similar. For all approvals, holder must develop a proposal for GW Monitoring Program that includes:

- Hydrogeologic description and interpretation of the plant
- At the plant:
    - Maps of surface water drainage patterns
    - Maps and cross-sections of lithologic units (surficial and upper bedrock)
    - Water table, flow direction and gradient
    - Hydraulic conductivity of all materials
    - GW monitoring network (location, description, logs)
    - Description of GW sampling
- GW response plan, should contaminants be identified through GW monitoring (this is a very vague requirement, without much detail)

Holder must submit Annual GW Monitoring Program Summary Report that includes among other

- General hydrogeological description for 5 km radius from plant, including location of GW and SW users + water usage
- Detailed hydrogeo description of plant + similar requirements as those listed above for Suncor surface mining

PetroCanada and Northstar's approvals have tables that list GW monitoring wells and parameters that must be analyzed for each well. The list of parameters varies according to location of the wells, with fewer parameters for wells located further away. Approvals list specific wells designed to monitor: plant site, GW diversion, well pads, landfill monitoring. Examples of parameters that have to be monitored include:

- Routine Potability parameters
- Total phenols
- Dissolved ammonia nitrogen
- Dissolved Kjeldahl nitrogen
- Total phosphate
- Dissolved metals (As, Barium, Beryllium, boron, Cd, Cr, Co, Cu, Fe, Pb, Mn, Mb, Ni, phosphorous, Se, Si, Sr, Ag, thallium, tin, titanium, vanadium, Zn)
- PAHs
- BTEX/TPH
- TEH to C30
- TEH C30-C60
- Naphthenic acids
- glycol

APPENDIX A5 EXAMPLE OF A WATER MANAGEMENT PLAN – COLD LAKE-BEAVER RIVER

Lemay et al. (2005) and Parks et al. (2005) have compiled and analyzed groundwater data in the Cold Lake-Beaver River Drainage Basin, to help update the Beaver River-Cold Lake Water Management Plan. Preliminary results from the groundwater quality study indicate that the regional groundwater chemical quality is generally within Canadian drinking water quality guidelines, without detectable changes over time (Lemay et al. 2005). Some areas within the Basin are potentially sensitive to contamination because of point and nonpoint sources of contamination. With respect to the groundwater flow dynamics, Parks et al. (2005) provide evidence that groundwater in drift aquifers is in hydraulic contact with surface water. Groundwater extraction from these aquifers could affect surface water within five years from start of pumping. A water management approach that integrates surface water and groundwater is therefore suggested, but further study of surface water and groundwater interactions in the Basin is needed.

Using results from the Lemay et al. (2005) and Parks et al. (2005) regional studies, the Cold Lake-Beaver River Water Management Plan adopted in 1985 was updated in 2006 to account for a long period of below normal precipitation combined with increased industrial development and population growth (AEnv 2006b). Compared to the previous plan, the new plan proposed an integrated approach where surface water and groundwater are recognized as a single resource, as proposed in the Parks et al. (2005) report.

APPENDIX A6 RECLAMATION PLANT SPECIES

Table A6.1 Plant species used in reclamation research in the Alberta oil sands

Common Name	Scientific Name
Acute leaf willow	*Salix acutifolia*
African tamarisk	*Tamarix africana*
Anglo jewish yew	*Taxus x media, Taxus bacata*, *Taxus cuspitdata*
Alaskan birch	*Betula neoalaskensis*
Alaskan wheat grass	*Agropyron latiglume*
Alder leaf buckthorn	*Rhamnus alnifolia*
Alfalfa	*Medicago sativa*
Alpine blue grass	*Poa alpina*
Alpine milk vetch	*Astragalus alpinus*
Alpine sweet vetch	*Hedysarum alpinum*
Alpine timothy	*Phleum commutatum, Phleum alpinum*
Alsike clover	*Trifolium hybridium*
Altai wild rye	*Elymus angustus, Leymus angustus*
Alum root	*Heuchera richardsonii*
American dragon head	*Moldavica parviflora, Dracocephalum parviflorum*
American dune grass	*Elymus mollis*
American elm	*Ulmus americana*
American milk vetch	*Astragalus americanus, Astragalus frigidus*
American vetch	*Vicia americana*
American water plantain	*Alisma plantago-aquatica*
Amur maple	*Alnus ginnala*
Antelope bitterroot	*Purshia tridentata*
Annual hawk beard	*Crepis tectorum*
Annual sunflower	*Helianthus annuus*
Annual wild rice	*Zizania aquatica*
Arctic lupine	*Lupinus arcticus*
Arrow leaf colts foot	*Petatsistes sagittatus*
Arum leaf arrow head	*Sagittaria cuneata*
Aulacomnium moss	*Aulacomnium palustre*
Autumn willow	*Salix serissima*
Awned wheat grass	*Agropyron subsecundum*
Arctic brome	*Bromus pumpellianus*
Balsam fir	*Abies balsamea*
Balsam poplar	*Populus balsamifera*
Barley	*Hordeum vulgare*
Balsam willow	*Salix pyrifolia*
Baltic rush	*Juncus balticus*
Baneberry	*Actaea rubra*
Barclay willow	*Salix canadensis*
Basin wild rye	*Elymus cinereus*
Bastard toad flax	*Comandra umbellata*
Bay willow	*Salix petandra*
Beaked hazelnut	*Corylus cornutata*
Beaked willow	*Salix bebbiana*
Beaked sedge	*Carex rostrata*
Bean	*Phaseolus vulgaris*
Bearberry	*Arctostaphylos uva-ursi*
Bearded wheat grass	*Agropyron subsecundum*
Beet	*Beta vulgaris*
Bering's tufted hair grass	*Deschampsia beringensis*

Bicknell's geranium	*Geranium bicknellii*
Bird vetch	*Vicia cracca*
Bird's foot trefoil	*Lotus corniculatus*
Bishop's cap	*Mitella nuda*
Black alder	*Alnus glutinosa*
Black bind weed	*Polygonum convolvulus*
Black hawthorn	*Rhamnus lycioides*
Black spruce	*Picea mariana*
Black walnut	*Juglans nigra*
Blueberry	*Vaccinium myrtilloides*
Blueberry willow	*Salix myrtillifolia*
Blue bunch wheat grass	*Agropyron spicatum, Agropyron pectiniforme, Pseudoroegneria spicata*
Blue eyed grass	*Sisyrinchium montanum*
Blue grama grass	*Bouteloua gracilis*
Blue joint	*Calamagrostis canadensis*
Blue spruce	*Picea pungens*
Bog birch	*Betula glandulosa*
Bog cranberry	*Vaccinium vitis-idaea*
Bog laurel	*Kalmia polifolia*
Bog rosemary	*Andromeda polifolia*
Box elder	*Acer negundo*
Bracted honeysuckle	*Lonicera involucrata*
Bran lichen	*Parmeliopsis* spp.
Bristly black currant	*Ribes lacustre*
Brittle willow	*Salix fragilis*
Broad glumed wheat grass	*Agropyron violaceum, Agropyron latiglume*
Broccoli	*Brassica oleracea* var. *italica*
Broom weed	*Gutierrezia sarothrae*
Brown top	*Agrostis tenuis*
Buck wheat	*Fagopyrum esculentum*
Buffalo bean	*Astragulus crassicarpus*
Bulb bearing hemlock	*Ciculta bulbifera*
Bunchberry	*Cornus canadensis*
Bur oak	*Quercus macrocarpa*
Bush cinquefoil	*Potentilla fructicosa*
California brome	*Bromus carinatus*
California nettle	*Urtica gracilis*
Canada anemone	*Anemone canadensis*
Canada blue grass	*Poa compressa*
Canada buffalo berry	*Shepherdia canadensis*
Canada goldenrod	*Solidago canadensis, Solidago lepida*
Canada mayflower	*Maianthemum canadense*
Canada milk vetch	*Astragalus canadensis*
Canada thistle	*Cirsium arvense*
Canada wild rye	*Elymus canadensis*
Canada yew	*Taxus canadensis*
Canary island pine	*Pinus canariensis*
Canola	*Brassica napus, Brassica rapa, Brassica campestris*
Caragana	*Caragana arborescens*
Carrot	*Daucus carota*
Cattail	*Typha latifolia*
Cauliflower	*Brassica oleracea*
Celery leaved buttercup	*Ranunculus schleratus*
Chickweed	*Stellaria arenicola, Stellaria media*
Chinese chestnut	*Castanea mollissima*
Chinese elm	*Ulmus parvifolia*

Chinese juniper	*Juniperus chinensis*
Choke cherry	*Prunus virginiana*
Cicer milk vetch	*Astragalus cicer*
Ciliate hedwigia moss	*Hedwigia ciliata*
Cloud berry	*Rubus chamaemorus*
Colorado spruce	*Picea pungens*
Colonial bent grass	*Agrostis capillaris*
Coltsfoot	*Tussilago farfara*
Common cattail	*Typha latifolia*
Common duckweed	*Lemna minor*
Common lilac	*Syringa vulgaris*
Common juniper	*Juniperus communis*
Common paint brush	*Castilleja miniata*
Common pink wintergreen	*Pyrolaasarifolia*
Common plantain	*Plantago major*
Common reed	*Phragmites australis*
Common spike rush	*Eleocharis palustris*
Common tansy	*Tanacetum vulgare*
Common water plantain	*Alisma plantago-aquatica*
Corn	*Zea mays*
Cotton	*Gossypium* sp.
Crack willow	*Salix fragilis*
Creamy peavine	*Lathyrus ochroleucus*
Creeping bent grass	*Agrostis stolonifera, Agrostis alba*
Creeping foxtail	*Alopecurus arundinacea*
Creeping meadow foxtail	*Alopecurus arundinacea, Alopecurus ventricosus*
Creeping red fescue	*Festuca rubra*
Creeping willow	*Salix argentea*
Crested wheat grass	*Agropyron cristatum*
Creeping juniper	*Juniperus horizontalis*
Creeping white prairie aster	*Aster falcatus*
Crimson clover	*Trifolium incarnatum*
Crow berry	*Empetrum nigrum*
Crown vetch	*Coronilla viminalis, Coronilla juncea*
Curved sedge	*Carex maritima*
Cut leaved anemone	*Anemone multifida*
Dahurian buckthorn	*Rhamnus davurica*
Dandelion	*Taraxacum officinale*
Desert goosefoot	*Chenopodium pratericola*
Dewberry	*Rubus pubescens*
Disc mayweed	*Matricaria discoidea*
Dotted blazing star	*Liatris punctata*
Douglas fir	*Pseudotsuga menziesii*
Downy birch	*Betula alba*
Downy brome	*Bromus tectorum*
Drooping wood reed	*Cinna latifolia*
Dwarf bilberry	*Vaccinium caespitosum*
Dwarf birch	*Betula glandulosa, Betula pumila*
Early blue violet	*Viola adunca*
Early yellow locoweed	*Oxytropis sericea*
Eastern flowering dogwood	*Cornus florida*
Eastern teaberry	*Gaultheria procumbens*
Eastern white cedar	*Thuja occidentalis*
Eastern white pine	*Pinus strobus*
Egg yolk lichen	*Candelariella aurella*
Elderberry	*Sambucus racemosa*

Elegant milk vetch	*Astragalus eucosmus*
Engelmann spruce	*Picea engelmanii*
European bird cherry	*Prunus padus*
European larch	*Larix decidua*
False melic	*Schizachne purpurascens*
False mountain willow	*Salix pseudomonticola*
False solomons seal	*Maianthemum racemosum*
Field bindweed	*Convolvulus arvensis*
Field chickweed	*Cerastium arvense*
Field locoweed	*Oxytropis campestris*
Fire weed	*Epilobium angustifolium*
Flat pea	*Lathyrus sylvestris*
Flixweed	*Descurainia sophia*
Foxtail barley	*Hordeum jubatum*
Four wing saltbrush	*Atriplex canescens*
Fowl blue grass	*Poa palustris*
Fowl manna grass	*Glyceria grandis, Glyceria striata*
Fragile tortella moss	*Tortella fragilis*
Fringed brome	*Bromus ciliatus*
Fringed willow herb	*Epilobium glandulosum*
Gaillardia	*Gaillardia aristata*
Gian bur reed	*Sparganium eurycarpum*
Giant saltbrush	*Atriplex nummularia*
Glaucous blue grass	*Poa glauca, Poa glaucantha*
Golden alder	*Alnus alnifolia*
Golden bean	*Thermopsis rhombifolia*
Golden cordalis	*Corydalis aurea*
Gray leaf willow	*Salix villosa, Salix glauca*
Greater water dock	*Rumex orbiculatus*
Green alder	*Fraxinus pennsyvanica*
Green ash	*Fraxinus pennsylvanica*
Green leaf rock rose	*Cistus albidus*
Green needle grass	*Stipa viridula*
Green reindeer lichen	*Cladina mitis*
Green smartweed	*Polygonum lapifolium*
Grey leaved cistus	*Cistus albidus*
Hairy arnica	*Arnica mollis*
Hairy wild rye	*Elymus innovatus*
Hard sheep fescue	*Festuca trachyphylla*
Hard stem bulrush	*Scirpus acutus*
Harebell	*Campanula rotundifolia*
Hawk weed	*Hieracium canadense*
Hawks beard	*Crepis tectorum*
Hawthorn	*Crataegus cerronis*
Heart leaved arnica	*Arnica cordifolia*
Hemp nettle	*Galeopsis tetrahit*
High bush cranberry	*Viburnum edule, Vaccinium corymbosum, Viburnum opulus, Viburnum trilobum*
Hooker's oat grass	*Helictotrichon hookerii*
Horsetails	*Equisetum* spp.
Horse weed	*Erigeron canadensis*
Houghton sedge	*Carex houghtoniana*
Idaho fescue	*Festuca idahoensis*
Indian milk vetch	*Astragalus aboriginum*
Indian rape	*Brassica rapa* L. var. *silvestris*
Indian rice grass	*Oryzopsis hymenoides, Achnatherum hymenoides*
Inland blue grass	*Poa interior*

Intermediate wheat grass	*Agropyron intermedium*
Italian rye grass	*Lolium multiflorum*
Jack pine	*Pinus banksiana*
Japanese clover	*Kummerowia striata*
June grass	*Koeleria macrantha, Koeleria cristata*
Jungermann's orange lichen	*Caloplaca jungermanniae*
Kentucky blue grass	*Poa pratensis*
Kidney leaved violet	*Viola renifolia*
Knotweed	*Polygonum lapathifolium*
Kochia	*Kochia scoparia*
Labrador tea	*Ledum groenlandicum*
Lamb's quarters	*Chenopodium album*
Laurel willow	*Salix pentandra*
Leather leaf	*Chamaedaphne calyculata*
Lentil	*Lens culinaris*
Lettuce	*Lactuca sativa*
Licorice root	*Hedysarum mackenzii*
Lindley's aster	*Aster ciliolatus*
Little bluestem	*Schizachyrium scoparium*
Loblolly pine	*Pinus taeda*
Lodgepole pine	*Pinus contorta*
Long leaved violet willow	*Salix acutifolia*
Long stalk starwort	*Stellaria arenicola*
Lousewort	*Pedicularis furbishiae*
Low bilberry	*Vaccinium mytrillus*
Low bush cranberry	*Viburnum edule*
Low goldenrod	*Solidago missouriensis*
Mackenzie's willow	*Salix prolixa*
Manitoba maple	*Acer negundo*
Manna grass	*Glyceria pulchella*
Marsh cinquefoil	*Potentilla palustris*
Marsh grass	*Parnassia palustris*
Marsh marigold	*Caltha palustris*
Marsh sedge	*Carex palustris*
Marsh skullcap	*Scutellaria galericulata*
Mat muhly	*Muhlenbergia richardsonis*
Meadow rye grass	*Lolium pratense*
McCalla's willow	*Salix maccalliana*
Meadow barley	*Hordeum brachyantherum*
Meadow brome	*Bromus commutatus, Bromus elatior*
Meadow fescue	*Festuca elatior*
Meadow foxtail	*Alopecurus pratensis*
Meadow horsetail	*Equisetum pratense*
Meadow rue	*Thalictrum venulosum*
Mountain brome	*Bromus marginatus*
Mountain lichen	*Dimelaena oreina*
Mountain rye	*Secale multicaule*
Mutton grass	*Poa fendleriana*
Narrow leaf willow	*Salix exigua*
Narrow leaved reed grass	*Calamagrostis stricta*
Narrow leaves hawks beard	*Crepis tectorum*
Narrow leaf hawk weed	*Hieracium umbellatum*
Needle and thread grass	*Stipa comata*
Nodding brome	*Bromus anomalus*
Northern awnless brome	*Bromus pumpellianus*
Northern bed straw	*Galium boreale, Galium trifidum*

Northern black currant	*Ribes hudsonianum*
Northern gentian	*Gentianella amarella*
Northern gooseberry	*Ribes oxyacanthoides*
Northern reed grass	*Calamagrostis inexpansa*
Northern rice grass	*Oryzopsis pungens*
Northern rough fescue	*Festuca altaica*
Northern starflower	*Tridentalis borealis*
Northern wheat grass	*Agropyron dasystachyum*
Northern wild rice	*Zizania palustris*
Northern willow herb	*Epilobium ciliatum*
Nuttall's alkali grass	*Puccinellia nuttalliana*
Nuttall's saltbrush	*Atriplex nuttallii*
Oats	*Avena sativa*
Orchard grass	*Dactylis glomerata*
Ox eye daisy	*Chrysanthemum leucanthenum*
Palmate leaved colts foot	*Petasites palmatus*
Paper birch	*Betula papyrifera*
Parry's oat grass	*Danthonia parryi*
Pasture sage	*Artemisia frigida*
Peach leaf willow	*Salix amygdaloides*
Pepper grass	*Lepidiumdensiflorum*
Peppermint drop lichen	*Icmadophila ericetorum*
Perennial rye grass	*Lolium perenne*
Perennial sow thistle	*Sonchus arvensis*
Pin cherry	*Prunus pensylvanica*
Pink cordalis	*Cordalyis sempervirens*
Plains reed grass	*Calamagrostis montanensis*
Ponderosa pine	*Pinus ponderosa*
Porcupine grass	*Stipa spartea*
Polar grass	*Arctagrostis* spp.
Poplar hybrids	Various
Potato	*Solanum tuberosum*
Prairie bulrush	*Scirpus paludosus*
Prairie coneflower	*Ratibida columnifera*
Prairie crocus	*Anemone patens*
Prairie sage	*Artemisia ludoviciana*
Prickly rose	*Rosa acicularis*
Prostrate knotweed	*Polygonum aviculare*
Pubescent wheat grass	*Agropyron trichophorum*
Purple crown vetch	*Coronilla varia*
Purple peavine	*Lathyrus venosus*
Purple prairie clover	*Dalea lasiathera, Petalostemon purpureum*
Purple vetch	*Lathyrus venosa*
Pussy toes	*Antennaria parvifolia*
Pussy willow	*Salix discolor*
Quack grass	*Agropyron repens, Elymus repens*
Rattle box	*Rhinanthus borealis*
Red alder	*Alnus rubra*
Red ash	*Fraxinus pennsylvanica*
Red clover	*Trifolium pratense*
Red fruit berry	*Arctostaphylos rubra*
Red osier dogwood	*Cornus stolonifera*, *Cornus sericea*
Red pine	*Pinus resinosa*
Redtop	*Agrostis alba, Agrostis gigantea*
Reed canary grass	*Phalaris arundinacea*
River alder	*Alnus tenufolia*

Rocky mountain fescue	*Festuca saximontana*
Rocky mountain maple	*Acer glabrum*
Rough bent grass	*Agrostis scabra*
Rough cinquefoil	*Potentilla norvegica*
Rough fescue	*Festuca scabrella, Festuca campestris, Festuca hallii*
Running club moss	*Lycopodium clavatum*
Russian olive	*Elaeagnus angustifolia*
Russian silver berry	*Elaeagnus angustifolia*
Russian thistle	*Salsola kali*
Russian wild rye	*Elymus junceus, Psathyrostachys juncea*
Rye	*Secale cereale*
Sage leaf willow	*Salix candida*
Sainfoin	*Onobrychis viciifolia, Psoralea onobrychis*
Salmonberry	*Rubus parviflorus*
Salt grass	*Distichlis strica*
Sandbar willow	*Salix interior*
Sandberg's blue grass	*Poa sandbergii*
Sand dropseed	*Sporobolus cryptandrus*
Sand grass	*Calamovilfa longifolia*
Sand heather	*Hudsonia tomentosa*
Saskatoon berry	*Amelanchier alnifolia*
Scorpion weed	*Phacelia sericea*
Scouring rush	*Equisetum scirpoides*
Scotch pine	*Pinus sylvestris*
Sheep fescue	*Festuca ovina*
Shining willow	*Salix lucida*
Short fruit willow	*Salix brachycarpa*
Showy aster	*Aster conspicuus*
Showy locoweed	*Oxytropis splendens*
Shrubby cinquefoil	*Potentilla fruticosa*
Shrubby willow	*Salix arbusculoides*
Siberian elm	*Ulmus pumila*
Siberian larch	*Larix siberica*
Siberian yarrow	*Achillea siberica*
Silverberry	*Elaeagnus commutata*
Silver lupine	*Lupinus argenteus*
Skunk currant	*Ribes glandulosum*
Slash pine	*Pinus elliottii*
Slender arrow grass	*Triglochin palustris*
Slender cinquefoil	*Potentilla gracilis*
Slender wheat grass	*Elymus trachycaulus*, *Agropyron trachycaulum*, *Agropyron pauciflorum*
Slim stem reed grass	*Calamagrostis stricta*
Slough grass	*Beckmannia syzigachne*
Small bed straw	*Galium trifidum*
Small bog cranberry	*Vaccinium microcarpus, Oxycoccus microcarpus*
Small flower buttercup	*Ranunculus parviflorus*
Small flower columbine	*Aquilegia brevistyla*
Small yellow pond lily	*Nuphar variegatum*
Smooth aster	*Aster laevis*
Smooth brome	*Bromus inermis*
Smooth fleabane	*Erigeron glabellus*
Sneeze weed	*Helenium montanum*
Snowberry	*Symphoricarpos albus*
Soft stem bulrush	*Scirpus validus*
Sorghum	*Sorghum bicolor*
Sow thistle	*Sonchus arvensis*

Speckled alder	*Alnus rugosa, Alnus incana*
Spike trisetum	*Trisetum spicatum*
Spreading dogbane	*Apocynum androsaemifolium*
Spreading wheat grass	*Agropyron scribneri*
Squirrel tail	*Sitanion hystrix*
Stair step moss	*Hylocomiun splendens*
Stiff club moss	*Lycopodium annotinum*
Stiff goldenrod	*Solidago rigida*
Stinging nettle	*Urtica dioica*
Strawberry	*Fragaria virginiana*
Strawberry blite	*Chenopodium capitatum*
Streambank wheat grass	*Agropyron riparium, Elymus lanceolatus*
Subterraneum clover	*Trifolium subterraneum*
Sunflower	*Helianthus maximilianii*
Sweet clover	*Melilotus* sp.
Sweet grass	*Hierochloe odorata*
Sweet scented bedstraw	*Galium triflorum*
Swiss chard	*Beta vulgaris*
Tall buttercup	*Ranunculus acris*
Tall fescue	*Festuca arundinacea, Lolium arundinaceum*
Tall lungwort	*Mertensia paniculata*
Tall wheat grass	*Agropyron elongatum*
Tamarack	*Larix laricina*
Tartarian honeysuckle	*Lonicera tartarica*
Thorny buffaloberry	*Shepherdia argentea*
Three flowered aven	*Geum triflorum*
Three toothed cinquefoil	*Potentilla tridentata*
Tickle grass	*Agrostis scabra*
Timothy	*Phleum pratense*
Toad flax	*Linaria dalmatica*
Toad rush	*Juncus bufonis*
Tomato	*Solanum lycopersicum*
Trailing raspberry	*Rubus pubescens*
Trembling aspen	*Populus tremuloides*
Twin flower	*Linnaea borealis*
Twining honeysuckle	*Lonicera dioica, Lonicera dioica* var. *glaucescens*
Tufted hair grass	*Deschampsia caespitosa*
Tufted vetch	*Vicia cracca*
Tufted white prairie aster	*Aster pansus*
Valerian	*Valeriana dioica*
Vine maple	*Acer circinatum*
Water birch	*Betula occidentalis*
Water sedge	*Carex aquatilis*
Water smart weed	*Polygonum coccineum*
Weeping alkali grass	*Puccinellia distans*
Western clematis	*Clematis ligusticolia*
Western dock	*Rumex occidentalis*
Western porcupine grass	*Stipa curtiseta*
Western snow berry	*Symphoricarpos occidentalis*
Western wheat grass	*Agropyron smithii*
Wheat	*Triticum aestivum*
White clover	*Trifolium repens*
White grained rice grass	*Oryzopsis asperfolia*
White spruce	*Picea glauca*
White sweet clover	*Melilotus alba*
White sweet vetch	*Hedysarum sulphurescens*

White top grass	*Scholochloa festucacea*
Wide leaf polar	*Arctagrostis arundinacea, Arctagrostis latifolia* grass
Wild bergamot	*Monarda fistulosa*
Wild blue flax	*Linum lewisii*
Wild cranberry	*Vaccinium macrocarpon*
Wild licorice	*Glycyrrhiza lepidota*
Wild lily of the valley	*Maianthemum canadense*
Wild mint	*Mentha arvensis*
Wild red currant	*Ribes triste*
Wild red raspberry	*Rubus idaeus*
Wild rice	*Zizania aquatica*
Wild sarsaparilla	*Aralia nudicaulis*
Willow	*Salix racemosa*
Wire rush	*Juncus balticus*
Winterfat	*Eurotia lanata*
Wood oats	*Chasmanthium* spp.
Wood rose	*Rosa woodsii*
Wood rush	*Luzula parviflora*
Woodland horsetail	*Equisetum sylvaticum*
Wooly fruit sedge	*Carex lasiocarpa*
Wormwood	*Artemisia absinthium*
Yarrow	*Achillea millifolium*
Yellow avens	*Geum aleppicum*
Yellow evening primrose	*Oenothera biennis*
Yellow lucerne	*Medicago falcata*
Yellow reindeer lichen	*Cladina mitis*
Yellow sweet clover	*Melilotus offinalis*
Yellow umbrella plant	*Eriogonum flavum*
Yukon wheat grass	*Agropyron yukonensis*

Common and scientific names of the species are listed as reported in the various documents on revegetation in the oil sands and have not been standardized to a specific authority. This list does not attempt to include all species found on reclaimed sites or tested in oil sands reclamation, only those listed in the documents reviewed.

APPENDIX A7 RELEVANT ENVIRONMENTAL ASSOCIATION MEMBER LISTINGS

Wood Buffalo Environmental Association Member Listing

Alberta Energy and Utilities Board - www.ercb.ca
Alberta Environment - http://environment.alberta.ca/
Alberta Sustainable Resource Development - http://www.srd.gov.ab.ca/
Albian Sands Energy Inc - www.albiansands.com
Athabasca Tribal Council - www.atc97.org
Canadian Natural Resources Ltd. - www.cnrl.com
Fort McKay First Nation - www.atc97.org/ftmckayfn.html
Fort McKay Métis Local #122
Fort McMurray Environmental Association
Fort McMurray First Nation - www.atc97.org/ftmcmurrayfn.html
Husky Energy - www.huskyenergy.ca
Imperial Exxon-Mobil Oil - www.imperialoil.ca
Mikisew Cree First Nation - http://mikisew.org/
Métis Industry Consultation Association
Northern Lights Health Region - www.nlhr.ca
Nunee Board of Health
OPTI/Nexen - www.longlake.ca
Pembina Institute for Appropriate Development - www.pembina.org
Petro-Canada - www.petro-canada.ca
Regional Municipality of Wood Buffalo - www.woodbuffalo.ca
Saskatchewan Environment - http://www.environment.gov.sk.ca/
Suncor Energy Inc. - www.suncor.com
Syncrude Canada Ltd. - www.syncrude.com
Synenco - www.synenco.com
Total - www.total.com
Toxics Watch Society of Alberta www.toxwatch.ca/
UTS Energy Corporation - www.uts.ca
Williams Energy - www.williams.com

Regional Aquatics Monitoring Program (RAMP) Steering Committee Membership

Alberta Energy Resources Conservation Board (formerly Alberta Energy and Utilities Board	Alberta Environment	Alberta Pacific Forest Industries Inc.
Albian Sands Energy Inc.	Alberta Sustainable Resource Development	Birch Mountain Resources Ltd.
Canadian Natural Resources Ltd.	Environment Canada	Fisheries and Oceans Canada
Fort McMurray First Nation	Health Canada	Husky Energy
Fort McKay First Nation	Imperial Oil Resources	Mikisew Cree First Nation
Nexen Canada Inc.	OPTI Canada Inc.	Petro-Canada Oil and Gas
Regional Municipality of Wood Buffalo	Shell Canada Ltd.	Suncor Energy Inc.
Syncrude Canada Ltd.	Total E&P Canada Ltd.	

Cumulative Environmental Management Association (CEMA)

Our members include:

- Alberta Aboriginal Affairs & Northern Development
- Aberta Conservation Association
- Alberta Department of Energy
- Alberta Environment
- Alberta Fish and Game Association
- Alberta Health and Wellness
- Alberta Pacific Forest Industries Inc.
- Alberta Sustainable Resource Development
- Canadian Environmental Assessment Agency
- Canadian Natural Resources Ltd.
- Canadian Parks and Wilderness Society
- Chard Métis Local # 214
- Cenovus Energy Inc.
- Conklin Métis Local #193
- ConocoPhillips Canada
- Department of Fisheries and Oceans
- Devon Canada
- Ducks Unlimted Canada
- Environment Canada
- Energy Resources Conservation Board(ERCB)
- Fort Chipewyan Métis Local #125
- Fort McKay Métis Local #63
- Fort McKay First Nation
- Fort McMurray Field Naturalists
- Fort McMurray Métis Local #2020
- Health Canada
- Husky Energy Ltd.
- Imperial Oil Resources
- Japan Canada Oilsands Ltd.
- Keyano Collegehttp://www.jacos.com/
- MEG Energy
- Métis Nation of Alberta Region One
- Natural Resources Canada
- Nexen Inc.
- Nistawayou Association Friendship Centre
- Northern Lights Health Region
- Regional Municipality of Wood Buffalo
- Saskatchewan Environment
- Shell Canada
- Suncor Energy Inc.
- Syncrude Canada Inc.
- Total E&P Canada
- UTS Energy Corporation
- Wood Buffalo National Park

APPENDIX A8 EXTERNALITIES

Our starting point is a simple characterization of economic transactions as involving voluntary exchanges between buyers and sellers. The terms of these exchanges (including the price of any given "good") are governed by the operation of markets. Buyers capture all of the benefits associated with the consumption of the specific good in question, while sellers bear all of the costs associated with making this good. Under competitive conditions, the quantity of this good that is exchanged is such that for the last unit sold the benefits derived by the consumer are equal to the additional cost of production borne by the seller, which is itself equal to the market-determined price.

Note that all of the consequences of this kind of exchange are borne by the buyer and the seller—no one who is not involved in the transaction is affected by it. This means, among other things, that for each unit of the good produced and consumed the benefits derived by individual consumers are equal to the benefits derived by society as a whole. Similarly, the costs borne by sellers are equal to the costs that all of society bears for the production of this good. Stated differently, the private benefits of consumption are equal to its social benefits; there is also no difference between the private and social costs of production. This is at the heart of a well known result in the economics literature: under appropriate conditions, outcomes that are in the best interests of individual buyers and sellers are also optimal from the perspective of society as a whole and are thus considered to be economically efficient.

Let's now add a complication: what if the production of a given good gave rise to costs that are not fully borne by the producer/seller?[47] How would our simple characterization change if, for example, the production of a good generated emissions of a pollutant that, in turn, led to environmental damages that were felt more broadly than by the buyers and sellers of this good? Exchanges between buyers and sellers would now have consequences for individuals not involved in these transactions: such individuals would capture none of the consumption benefits, but would bear some of the costs associated with the environmental damages resulting from the production of this good.[48] This is a case of a "negative environmental externality", one where the social costs of production of a good *exceed* its private costs. As things stand, the terms of exchange (including the market-determined price) would *not* reflect the costs associated with the environmental damage linked to the production of the good. From the perspective of society as a whole, the unimpeded interaction of buyers and sellers of this good would now result in "too much" polluting emissions being generated by the production of this good: what is in the best interests of buyers and sellers would no longer be socially optimal (and thus no longer economically efficient). Specifically, by bearing some of the costs and capturing none of the benefits, all of society, it could be argued, would be implicitly subsidizing the production and consumption of this good.

[47] Of course, the same of type of argument as that outlined below can be made if it is the *consumption* of a good that gives rise to such costs.

[48] The determination of environmental damages and the resulting costs requires insights and contributions from numerous perspectives and disciplines, including biology, ecology, and economics, among others. From a research perspective, these tasks are inherently multi-disciplinary in nature.

From an economics perspective, the fundamental way to deal with this issue is to act to ensure that the terms of exchange between buyers and sellers of the good in question fully reflect the consequences of the polluting emissions: to "internalize the externality" such that, in the case considered, the private costs of production are made to equal the costs borne by society as a whole. One way to do this is to assign property rights to "the environment": those holding such property rights could then act to ensure that costs associated with any environmental damage linked to the production (and consumption) of this good are borne by its producers and consumers. One could think of holders of property rights to "the environment" as charging a fee per unit of pollution discharged, for example. In practice, however, this approach has rarely been implemented. In a sense, this is not too surprising: the assignment of property rights and the resulting explicit commodification of the environment would likely prove very difficult to defend politically.

One aspect of this possible approach to dealing with negative environmental externalities is shared with the other approaches to be discussed later, namely that the intervention of a "third party" is required to set things in motion. In the case above, a "third party" had to assign the property rights before any action to internalize the externality could occur. In most jurisdictions, this "third party" role can only be played by government. In turn, this underscores a key aspect of environmental stewardship in market-based economies: some form of government intervention is needed if the terms of exchanges between buyers and sellers are to reflect the consequences of any negative environmental externalities linked to the production and consumption of goods that give rise to the underlying environmental damage.

Environmental externalities can also be addressed through *prescriptive* (also called "regulatory" or "command-and-control") and *incentive-based* (also "economic" or "market") approaches. Callan and Thomas (2007, p.79; emphasis in original) succinctly characterize these two approaches as follows:

> **Command-and-control approach** A policy that directly regulates polluters through the use of rules or standards.
>
> **Market approach** An incentive-based policy that encourages conservation practices or pollution reduction strategies.

In the prescriptive approach, the government intervenes directly to prescribe choices and specify behaviours, such as imposing technology choices or setting standards for emissions of pollutants. As far as the incentive-based approach is concerned, the form of intervention is indirect, in the sense that the government introduces policy instruments to which individual polluters can respond in ways that they feel is most appropriate for them. Such instruments include pollution charges and emissions permits, among others. A polluter can react to the introduction of, let's say, an emissions charge in numerous ways, such as choosing to invest in pollution-abatement technology, or changing the goods production process, or reducing the production of the good in question (the activity that gives to the pollution in the first place), or a combination of all of these. In all cases, however, the polluter must balance the cost of reducing emissions by one more unit against paying the designated charge on that unit of emissions. Since the polluter can choose among alternative ways to react to the introduction of a market instrument, there is more flexibility in response but the link between the introduction of the

instrument and subsequent reductions in polluting emissions is less direct than under the command-and-control approach. Given the nature of economic instruments, however, it seems likely that policy implementation and administration costs would be higher under the market approach than under command-and-control.

In both cases, policy choices made by the government can help move the behaviour of polluters to—or at least closer to—that which is deemed socially optimal (and thus economically efficient). Even if there are cases of the successful use of market approaches (perhaps one of the best known such case is the use of emissions permits in addressing sulphur dioxide emissions by US electricity-generating plants), past experience suggests that governments around the world have been more comfortable using command-and-control approaches to address environmental externalities. From a political perspective, such a preference seems relative easy to explain. First, as noted above, the command-and-control approach involves direct interventions. As a result, it is easier to ascribe reductions in polluting emissions to the fact that, for example, regulations dictate the choice of emissions-reducing technologies by polluters (than to the fact that polluters are changing their behaviour in reaction to the introduction of a charge per unit of emissions, for example). Second, the cost of reducing emissions is more difficult to identify—and thus less politically "visible"—under command-and-control than if an economic instrument, such as emissions permits, is used to accomplish the same goal. Under both approaches, the terms of exchanges between buyers and sellers will be altered by the policy intervention, but under command-and-control it is much more difficult to link these changes to the intervention itself since these could also result from numerous other factors (such as changes in wages and transportation costs, for example). By contrast, an emissions charge or the price of an emissions permit is quite "visible" to buyers and sellers, and the connection to changes in the terms of exchange for goods—and the fact that these result from government intervention—can be made much more readily.

From an economics perspective, however, there is an important drawback to relying on command-and-control approaches to address environmental externalities. Basically, it can be shown that in general any given reduction in polluting emissions will be more costly to achieve under command-and-control than under market approaches—the latter are thus said to be more cost-effective in achieving environmental objectives. The basic insight here has to do with the consequences of the distribution of emissions reductions among polluters.

Under command-and-control, the distribution of emissions reductions among polluters flows from the policy instrument adopted without any reference to differences in emissions-reduction costs across these polluters: all have to meet (or adopt) the mandated standard (or technology), for example. Things are different if an economic instrument (again, a charge per unit of emissions) is used to achieve *the same objective* in terms of emissions reductions. Here, each polluter will decide whether to reduce emissions by one more unit, or to pay the charge on that unit. Depending on the structure of emissions-reduction costs that they face, different polluters will choose to reduce emissions by different amounts. The government can thus choose the value of the per-unit emissions charge to achieve any given amount of *total* (across all polluters) emissions reductions. The key thing here, however, is that at the given total amount of reductions, the cost of reducing emissions by one more unit will be the same

across all polluters and will be equal to the per-unit emissions charge. In other words, the value of the charge is such that the desired total amount of emissions reductions is achieved when each polluter is indifferent between emitting the last unit of pollution that they produce (and thus pay the emissions charge on that unit) and acting to cut that last unit of emissions (and thus avoid paying the charge on it). In more technical terms, the marginal cost of emissions reduction (or abatement) is equal across all sources of a given pollutant. Since this is the case, it is therefore impossible to reduce the total cost of achieving any given level of emissions reductions by re-distributing reductions among polluters. As a result, the use of the economic (or market) instrument can be said to be cost-effective: it is not possible to achieve the specified environmental objective at a lower total cost. From a policy-making perspective, the indirect link between the economic instrument and the ultimate reduction in pollution creates a communications challenge; however, the link between that same instrument and the pocketbooks of voters is typically much more direct.

There is also a dynamic advantage to the use of economic instruments. Basically, once the underlying condition addressed by a command-and-control instrument has been reached—for example, one a specified emissions standard is attained—there is little (if any) policy-driven incentive for emitters to continue to improve their environmental performance in the absence of explicit changes in the standard. When an economic instrument (such as an emissions charge) is used, however, there is always an incentive to consider reductions in polluting emissions since emitters can always avoid paying the charge through actions (including technological innovations) that reduce emissions.

In addition to issues relating to the choice of approach and instruments, there are also more general challenges to government action on environmental objectives. Most of these challenges can be grouped under three broad headings: the level and distribution of the costs of action; difficulties associated with linking the cost of acting and the resulting benefits; and competitiveness issues. It is clear that addressing environmental objectives generally imposes costs on polluters (and in some cases on their customers) that they would not otherwise have to bear. Not only are these additional costs a source of controversy and reluctance to act, but so is the distribution of these costs across sectors of the economy and groups of consumers. Sectors that generate proportionately more polluting emissions will feel targeted by government action on this front. In a similar vein, from a policy-making perspective, acting to induce pollution abatement will be more difficult if the resulting additional costs fall disproportionately more heavily on lower-income individuals and households.

A second type of challenge relates to the fact that those who bear the costs of acting to reduce pollution will not share to the same extent in the benefits generated by their actions. For any cost distribution, this becomes increasingly controversial as the distribution of benefits widens. The case of climate policy and greenhouse gas (GHG) emissions is instructive here. For example, the costs of Canadian firms acting to reduce GHG emissions would be borne by these firms (and possibly their customers). The benefits flowing from these actions, however, would be felt around the world. These huge differences in the distribution of costs and benefits clearly make it more difficult for governments to justify taking action in this kind of situation.

Finally, competitiveness issues are frequently brought up whenever government action aimed at reducing environmental footprints is considered. Within a given jurisdiction, to the extent that the

consequences of such action would be unevenly felt across economic sectors, then the position of sectors relative to one another will change, with those most (negatively) affected seeing their competitiveness suffer vis-à-vis that of the other sectors. By extension, this type of argument can be extended to the situation where trade (and investment) can flow across jurisdictions. If some jurisdictions act to reduce emissions of a given pollutant and other don't, then the firms located in the jurisdictions that act will have to bear costs additional to those borne by their competitors located elsewhere and thus impede their ability to compete in markets that span both types of jurisdictions. Production and investment patterns will reflect these inter-jurisdictional differences, including the (negative) competitiveness effects on firms located in the jurisdictions that act.

Appendix A8 Reference

Callan, S. J., and J. M. Thomas. 2007. *Environmental Economics & Management: Theory, Policy, and Applications*, fourth edition. Mason OH: Thomson Southwestern.

14.12 Traditional Ecological Knowledge and Land Use

14.12.1 Project Refinements

This section provides a qualitative assessment update of the project effects on traditional ecological knowledge and traditional land use (TEK–TLU) within the project and surrounding areas. The project refinement that is relevant to the TEK–TLU assessment since submission of the 2007 SI Project Update is the increase in the project footprint (see Section 11.3.1).

14.12.2 Approach and Methods

The following project effects are addressed, similar to the 2007 SI Project Update:

- Moose Lake trail
- Ells River
- Joslyn Creek and a Jack pine area
- trapping

Potential effects on TEK and TLU are also addressed in response to Joint Review Panel (JRP) Additional Information Responses (AIR) Question 1 to Question 4.

In 2005, a TEK–TLU study was commissioned for the Joslyn Lease with Fort McKay First Nation (DCEL 2005). This study identified a number of issues of concern to the local traditional users and identified specific traditional use sites. Representatives of the Fort McKay Industrial Relations Corporation (IRC) indicated that the TEK–TLU study completed for the 2006 Integrated Application, Volume 5, Consultant Report 12 was sufficient for the 2007 SI Project Update, Section 13.12.4. In addition, a *Fort McKay First Nation Traditional Knowledge Report* was completed and published in May 2009 (Shell Pierre River Mine Project, Supplemental Information, Volume 2, Appendix A). At the time of this submission, the Fort McKay IRC has not requested any further TEK–TLU work be completed for the project.

The Fort McMurray 468 First Nation published a Traditional Land Use Study in 2006 titled *Nistawayaw: Where Three Rivers Meet* (Fort McMurray 468 First Nation 2006.) and provided TEPJ with a copy in 2008.

TEPJ has also participated in joint industry funded traditional knowledge studies with Fort McMurray Elder's Society, the Wood Buffalo Elders Society and the Fort McMurray Métis Local 1935. In 2008, the *Wood Buffalo Elders Interview Project* (Golder 2008) was completed and submitted to the funding parties.

In 2008 TEPJ contributed funding to the Fort McMurray Métis Local 1935 project titled *Mark of the Métis.* The project effort included interviewing about 25 elders from the area. Métis Local 1935 has stated the project is only in the first phase of completion.

Studies for the Athabasca Chipewyan First Nation (ACFN) and the Mikisew Cree First Nation (MCFN), funded by TEPJ, were commenced in mid 2008 and are ongoing.

For a description of project-related public consultation, including TLU study funding, see Section 16.

14.12.3 Assessment

14.12.3.1 Moose Lake Trail

The Moose Lake Trail traverses the project development area within the Joslyn Lease. Additional effects on the trail due to the revised project are not expected. Measures to mitigate effects will remain the same as those proposed in the responses to *Integrated Application Review Recommendations on Joslyn North Mine Project* FMFN Recommendations 115 and 116, available from the Joint Review Panel Canadian Environmental Assessment Agency Registry, and includes the development of an access management plan.

14.12.3.2 Ells River

Effects on the Ells River due to the project are not predicted (see Section 14.8.3 and Section 14.11.3). Measures to mitigate effects will remain the same as those indicated in the 2007 SI Project Update, Section 13.12.3.2.

14.12.3.3 Joslyn Creek and Jack Pine Area

As with the 2007 SI Project Update, the current plan is to have a permanent realignment of Joslyn Creek. No additional effects on traditional land use are expected as a result of project refinements. For information on the permanent realignment of Joslyn Creek, see Section 8.5.2.

Effects on the Jack pine area were considered in the 2007 SI Project Update, Section 13.12.3.3 and remain the same in this assessment.

14.12.3.4 Hunting and Trapping

As documented in the 2007 SI Project Update, Section 13.12.3.4, three trappers hold Registered Fur Management Agreements (RFMAs) on the Joslyn Lease, only two of which are affected directly by the project. Both RFMA holders are consulted on a regular basis to discuss surface land activities, and where applicable, provide compensation.

Early in the life of the project, portions of the project development area might be accessible for traditional hunting activities, and such opportunities will be discussed with First Nations as the mine progresses. However, as the mine advances, it can be anticipated that hunting activity will largely be excluded from the project development area for the safety of the public and mine workers.

Outside of the project development area, project activities will have little effect on traditional hunting activities. The project will be utilizing the existing CNRL road to access the project site, and will not be developing any significant new road access outside of the project development area. In addition, project workers will be prohibited from carrying firearms onto the mine site.

14.12.4 References

14.12.4.1 Literature Cited

DCEL (Deer Creek Energy Limited). 2005. *Joslyn In-Situ Oil Sands Project Traditional Land Use Report.* Prepared by: FMA Heritage Resources Consultants Inc. February 2005.

Fort McMurray 468 First Nation. 2006. *Nistawayaw, "Where Three Rivers Meet".* Fort McMurray 468 First Nation: Traditional Land Use Study. Calgary, Alberta. Nicomacian Press.

Golder (Golder Associates Ltd.). 2008. *Wood Buffalo Elders Interview Project: Final Report.* Fort McMurray Elder's Society, the Wood Buffalo Elders Society and the Fort McMurray Métis Local 1935.

Shell (Shell Canada Limited). 2007. *Application for Approval of the Jackpine Mine Expansion Project and Pierre River Mine Project.* Traditional Knowledge and Land Use Study, Volume 5, Section 8.1.

APPENDIX A10 PUBLIC HEALTH LITERATURE SEARCH STRATEGY

1. Introduction

The purpose of this section is to outline approaches that were used for conducting a comprehensive search of the scientific literature concerning the health impacts of oil sands exploitation, for compiling and managing data as well as tracking the references.

The first step in this literature search was to define the research question and identify relevant keywords with the help of a librarian specialized in medical sciences at Laval University in Québec City. Then, main sources of information were identified and Boolean searches were performed using search engines available on the web as well as online databases. Lastly, personal contacts and experts in the field were contacted.

2. Research Question and Keywords

The research question was defined as: *What are the known (or possible) health impacts of the development of oil sands exploitation?*

Different search concepts and associated keywords were identified (Table 1).

Table 1: Search concepts and associated keywords

Search Concepts	Associated relevant keywords
Oil Sands	Tar sands; Bituminous sands; Asphaltic sands
Petroleum	combustible fuels; petrochemicals; lubricants; crude oils
Hydrocarbons	Volatile organic compounds
Environmental Exposure	Environmental Monitoring, Inhalation Exposure, Maternal Exposure, Maximum Allowable Concentration, Occupational Exposure, Paternal Exposure, Environmental Remediation, Food Contamination, Noise, Waste Products, Water Pollution
Environmental Pollutants	Air Pollution; Biofouling; Body Burden; Environmental Exposure; Environmental Remediation; Food Contamination; Noise; Waste Products; Water Pollution; Epidemiologic Factors; Epidemiologic Measurements; Epidemiologic Methods; Equipment Contamination; Hygiene; Public Health Practice;Radiologic Health ;Sanitation
Environmental Illness	Multiple Chemical Sensitivity; Sick Building Syndrome; Hypersensitivity; Delayed; Hypersensitivity; Immediate Immune Complex Diseases; Latex Hypersensitivity; Wissler's Syndrome
Public Health	Epidemiology; preventive medecine

Occupational Health	Occupational medicine, Occupational safety
Occupational Diseases	Dermatitis, Occupational ; Hand-Arm Vibration Syndrome ; Inert Gas Narcosis; Laboratory Infection ;Pneumoconiosis ;Sleep Disorders, Circadian Rhythm
Disorders of Environmental Origin	DNA Damage ; Environmental Illness; Multiple Chemical; Sensitivity; Sick Building Syndrome; Motion Sickness; Occupational Diseases; Poisoning; Preconception Injuries; Substance-Related Disorders; Wounds and Injuries
Accidents, Occupational	Industrial Accidents
Environmental Health	Sanitary Engineering ; Sanitation
Population Growth	Population explosion
Social environment	Community network, social support
Alberta	N/A
Athabasca	N/A

3. Sources of information

3.1 Web-based searches

We performed an initial search for relevant worldwide web (www) sites using search engines. Google.com (including Google Books and Google Scholar) was searched on December 1, 2009 to first get a sense of the amount of published information on the issue and second to search for peer-reviewed publications and grey literature. Also, Scirus.com a search engine for scientific information on the web was searched December 9, 2009.

3.2 Databases

PubMed was used with the following mesh on December 14, 2009:

((("Environmental Exposure"[Mesh] OR "Environmental Pollutants"[Mesh]) OR "Environmental Illness"[Mesh]) OR ((((((("Public Health"[Mesh])) OR ("Occupational Health"[Mesh])) OR ("Occupational Diseases"[Mesh])) OR ("Disorders of Environmental Origin"[Mesh])) OR ("Accidents, Occupational"[Mesh]))) OR ("Environmental Health"[Mesh]))) AND ((("Petroleum"[Mesh])) OR ("Hydrocarbons"[Mesh])) AND ("Extraction and Processing Industry"[Mesh]))) AND (Alberta OR Athabasca)

Web of Science, a very broad scientific and social sciences database as well as Proquest (Digital Dissertations) and Scopus, an online abstract and citation database of peer-reviewed literature, was also searched using advanced search with equivalent keywords.

3.3 Grey Literature Searches

Grey literature comprises publications not published commercially or indexed by major databases. We searched for grey literature in government sites, institutional repositories and association sites. Here is a complete list of consulted sites between December 9 and 15, 2009:

- Library and Archives Canada
- Canadian Centre for Policy Alternatives
- Canadian Health Services Research Foundation (CHSRF)
- Canadian Institutes of Health Research (CIHR)
- Canadian Center for Occupational Health and Safety (CCOHS) National Research Council (NRC)
- Canadian Institute for Health Information (CIHI)
- The Fraser Institute
- Health Canada
- Index to Canadian Federal "Royal Commission Reports"
- Industry Canada
- NRCAN Geological Survey Current Research
- Public Health Agency of Canada
- Statistics Canada
- UBC Library - Searching for Health Statistics and related publications
- University of Toronto - Environmental Studies Grey Literature
- University of Alberta
- The National Academies
- Alberta Environment
- Alberta Health and Wellness
- The oil sands development group ?

3.4 Citations and Manual Searches

Literature was identified by conducting citations searches of the bibliographies of the papers identified as relevant. Citation and manual searching were also effective ways of identifying more recent studies not identified in the initial literature search; this approach therefore complemented the databases searches by identifying information that may not have been captured initially.

3.5 Personal or Expert Contacts

We identified and contacted individual experts and members of other organizations and agencies for leads to data and information that may not have been readily accessible from the open literature. People contacted were:

- Preston McEachern, Section Head of the Science, Research and Innovation, Oil Sands Environmental Management Division at Alberta Environment. Contacted by email on April 26, 2010.
- Steve Burgess, Executive Director, Project Reviews, Canadian Environmental Assessment Agency (CEAA), contacted by email and phone on April 7, 2010.
- Roy E. Kwiatkowski, Chief, Environmental Health Assessment Services
  Health Canada, contacted by phone on April 1, 2010.

4. References

Reference Manager® was used for organizing, tracking and managing references. Using this software, references were exported from diverse databases and a reference list was created.