IN THE MATTER OF THE *RESPONSIBLE ENERGY DEVELOPMENT ACT* Statutes of Alberta, 2012, C. R-17.3; AND THE *OIL SANDS CONSERVATION ACT*, R.S.A. 2000, C. 0-7 Section 10 and 11 and Sections 3, 24, and 26 of the *Oil Sands Conservation Rules*, Alberta Regulation 76/88;

AND IN THE MATTER OF THE *CANADIAN ENVIRONMENTAL ASSESSMENT ACT*, 2012, SC 2012, c 19, s 52;

AND IN THE MATTER OF A JOINT PANEL REVIEW BY THE ALBERTA ENERGY REGULATOR AND THE GOVERNMENT OF CANADA, REGARDING:
FRONTIER OIL SANDS MINE PROJECT
TECK RESOURCES LIMITED;
CEAR Reference No.: 65505
AER Application No. 1709793

Volume 1 of 10
SUBMISSIONS
OF THE OIL SANDS ENVIRONMENTAL COALITION
and APPENDICES TO WRITTEN SUBMISSIONS
AUGUST 31, 2018

Submitted To:
Joint Review Panel Secretariat

Canadian Environmental Assessment Agency
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19	Environment and Climate Change Canada, *Canada's Seventh National Communication on Climate Change and Third Biennial Report*, (Gatineau: 2017)	633
20	Environment and Climate Change Canada, *Progress towards Canada's greenhouse gas emissions reduction target*, (Gatineau: 2018)	949
21	Sonia Yeh et al, "Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands," (2010) 44 Enviro. Sci. Tech	961
22	Statistics Canada, *Report on Energy Supply and Demand in Canada, 2016 Preliminary* (Ottawa, 2018)	993
Volume 5 **Submissions by the Oil Sands Environmental Coalition** **Selected references from Frontier *Oil Sands Mine Project: Review of liability management and financial security options***		
23	Dalmia, Avinash, "Analysis of naphthenic acids in filtered oil sands process water (OSPW) using LC/TOF with no sample preparation" (2013) Perkin Elmer: Application Note	1126
24	Grewer DM et al., "Naphthenic acids and other acid-extractables in water samples from Alberta: What is being measured?" (2010) Science of the Total Environment. doi:10.1016/j.scitotenv.2010.08.013	1131
25	Alberta Environment and Parks, Oil Sands Information Portal, "Regional Totals for Reclamation and Disturbance Tracking, by Year" (2016), online at http://osip.alberta.ca/library/Dataset/Details/27	1145
26	Auditor General of British Columbia, *An Audit of Compliance and Enforcement of the Mining Sector*, (Victoria: 2016)	1146
27	Auditor General of Alberta, *Report of the Auditor General of Alberta*, (Edmonton: July 2015)	1255
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28	Alberta Energy Regulator, "Mine Financial Security Program – Security and Liability", (Calgary: September 2017)	1373

IN THE MATTER OF THE *RESPONSIBLE ENERGY DEVELOPMENT ACT* Statutes of Alberta, 2012, C. R-17.3; AND THE *OIL SANDS CONSERVATION ACT*, R.S.A. 2000, C. 0-7 Section 10 and 11 and Sections 3, 24, and 26 of the *Oil Sands Conservation Rules*, Alberta Regulation 76/88;

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Table of Contents

A DESCRIPTION OF INTERVENORS

1. The Oil Sands Environmental Coalition ("OSEC") is a coalition of Alberta public interest groups with a longstanding interest in the Athabasca oil sands area. OSEC was formed to facilitate more efficient participation in the regulatory approvals process for oil sands applications. Its members include:

a) The Fort McMurray Environmental Association ("FMEA"), consisting of residents living in and around Fort McMurray who are concerned about the effects of oil sands development on human health, the ecosystem and the socioeconomic quality of life in the Regional Municipality of Wood Buffalo, and who may be directly and adversely affected by the environmental and socioeconomic effects of the Frontier Oil Sands Mine Project ("Frontier" or the "Project"); and

b) The Pembina Institute ("Pembina"), an Alberta-based non-profit environmental research and policy analysis organization with members across Alberta. One of its objectives is to minimize the environmental impacts associated with fossil fuel development in Alberta. Pembina has monitored the health and environmental implications of oil sands development since the mid 1980s and has been particularly active in the assessment and management of long-term, chronic and cumulative impacts.

2. OSEC's primary objectives are:

a) monitoring the environmental implications of oil sands development; and

b) minimizing the environmental impacts associated with oil sands development in the Athabasca oil sands region.

3. OSEC has been engaged in reviewing and assessing oil sands development since the mid 1980's and has been particularly active in the assessment and management of long-term chronic and cumulative impacts. OSEC has provided evidence and/or submissions to the Alberta Energy Regulator ("AER"), Energy Resources Conservation Board ("ERCB") and Joint Review Panels at several hearings, including the following:

a) The 1993 Syncrude expansion hearing (under the name Syncrude Environmental Assessment Coalition);

b) The 1997 Syncrude Aurora Mine (Pembina Institute and Toxics Watch);

c) The 1998 Shell Canada Muskeg River Mine Project;

d) The 1999 Suncor Millennium Project;

e) The 1999 Syncrude Canada Mildred Lake Upgrader Expansion;

f) The 1999 PanCanadian Christina Lake Project;

g) The 2000 Petro-Canada McKay River Project;

h) The 2002 TrueNorth Fort Hills Project (Alberta Wilderness Association and OSEC);

i) The 2003 Joint Panel Review of the CNRL Horizon Project;

j) The 2003 Joint Panel Review of the Shell Jackpine Mine Phase 1 Project;

k) The 2006 Suncor Voyageur Expansion Project;

l) The 2006 Shell Albian Muskeg River Mine Expansion Project;

m) The 2006 Imperial Kearl Project;

n) The 2010 Total Joslyn North Mine Project;

o) The 2012 Shell Jackpine Mine Expansion Project;

p) The 2017 Enhanced Review Process for the Tailings Management Plan for the Suncor Base Plant; and

q) The 2017 Enhanced Review Process for the Tailings Management Plan for the Syncrude Aurora North oil sands mines.

4. Members of OSEC participated actively from 2000 to 2008 with other stakeholders in the Cumulative Environmental Management Association ("CEMA") to develop environmental management systems intended to preserve and to protect the long-term ecological integrity of the Athabasca region from industrial development. One OSEC member rejoined CEMA in 2010 as board member. OSEC members' specific involvement included:

a) Member of CEMA Board (2005-2008), as well as one OSEC member serving on the Board until CEMA was disbanded in 2016;

b) Officer at large – CEMA Management Committee;

c) Co-chair of NOx/SO2 management working group ("NSMWG");

d) Member of the Sustainable Ecosystems Working Group ("SEWG");

e) Member of the Surface Water Working Group ("SWWG");

f) Member of the Reclamation Working Group; and

g) Member of the Watershed Integrity Task Group.

5. OSEC members continue to assist with the planning and management of environmental assessment and monitoring in the region through other provincial and regional multi-stakeholder groups, including:

a) Wood Buffalo Environmental Association ("WBEA"): FMEA was a founding member of WBEA and served on the Governance Committee for 20 years. One representative of OSEC sat on the Board of Directors of WBEA until January 2018 and one member sat on the WBEA –Human Exposure Monitoring Program until 2014; and

b) The Alberta Biodiversity Monitoring Institute ("ABMI"): One OSEC member currently serves on the Board as vice chair.

6. An employee of Pembina was an individually appointed member of the Oil Sands Advisory Group ("OSAG") established by the Minister of Environment and Parks in July 2016, and sat on technical committees providing advice to the Minister on the mechanisms to implement the 100 Mt greenhouse gas emission ("GHG") limit for oil sands operations. Another staff member sat on the technical committee providing advice for the implementation of processes to address biodiversity and environmental concerns in the oil sands region.

7. OSEC members have a history of participation in Government of Alberta and AER fluid tailings working groups such as:

a) Representative of OSEC as an appointed environmental non-governmental organization ("ENGO") delegate at the multi-stakeholder Surface Water Quantity Management Framework working group hosted by the Alberta Environment and Parks (2013 - 2014);

b) Representative of OSEC as an appointed ENGO delegate at the multi-stakeholder Surface Water Quality Management Framework working group hosted by the Alberta Environment and Parks (2013-2014);

c) Representative of OSEC as an appointed ENGO delegate at the multi-stakeholder Tailings Management Framework ("TMF") workshops hosted by the Alberta Environment and Parks (2014);

d) Representative of OSEC as an appointed ENGO delegate at the multi-stakeholder Technical Advisory Committee ("TAC") for Tailings Regulatory Management, hosted by the Alberta Energy Regulator (2015-16);

e) Representative of OSEC as an appointed ENGO delegate at the multi-stakeholder Stakeholder Interest Group concerning the Tailings Management Framework (TMF), hosted by the Government of Alberta (2016-current);

f) Representative of OSEC as an appointed ENGO delegate at the multi-stakeholder Mine Financial Security Program - Tailings Management Framework ("MFSP-TMF") Working Group, hosted by the Government of Alberta (2016-2018); and

g) Representative of OSEC as an appointed ENGO delegate at the multi-stakeholder Integrated Water Management Working Group ("IWMWG") concerning the Tailings Management Framework, hosted by the Government of Alberta (2016-2018).

8. OSEC has a long-standing practice of working proactively with oil sands proponents, in order to resolve issues when possible. OSEC has met with Teck Resources Limited ("Teck") on numerous occasions regarding the Project and proactively sought to address outstanding concerns.

9. Pembina has published the following research reports about oil sands in Alberta:

- Oil Sands Fever: The Environmental Implications of Canada's Oil Sands Rush (2005);
- The Climate Implication of Canada's Oil Sands Development (2005);
- Carbon Capture and Storage: an Arrow in the Quiver of a Silver Bullet to Combat Climate Change – A Canadian Primer (2005);

- Troubled Waters, Troubling Trends (2006);
- Down to the Last Drop: The Athabasca River and Oil Sands (2006);
- Death by a Thousand Cuts: The Impacts of In Situ Oil Sands Development on Alberta's Boreal Forest (2006);
- Thinking Like an Owner: Overhauling the Royalty and Tax Treatment of Alberta's Oil Sands (2006);
- Carbon Neutral by 2020: A Leadership Opportunity in Canada's Oil Sands (2006);
- Haste Makes Waste: The Need for a New Oil Sands Tenure Regime (2007);
- Royalty Reform Solutions: Options for Delivering a Fair Share of Oil Sands Revenues to Albertans and Resource Developers (2007);
- Danger in the Nursery: Impact on Birds of Tar Sands Oil Development in Canada's Boreal Forest (2008);
- Catching Up: Conservation and Biodiversity Offsets in Alberta's Boreal Forest (2008);
- Taking the Wheel: Correcting the Course of Cumulative Environmental Management in the Athabasca Oil Sands (2008);
- Under-Mining the Environment: the Oil Sands Report Card (2008);
- Fact or Fiction: Oil Sands Reclamation (2008);
- Carbon Copy: Preventing Oil Sands Fever in Saskatchewan (2009);
- Upgrader Alley: Oil Sands Fever Strikes Edmonton (2009);
- Cleaning the Air on Oil Sands Myths (2009);
- Pipelines and Salmon in Northern British Columbia: Potential Impacts (2009);
- The Waters That Bind Us: Transboundary Implications of Oil Sands Development (2009);

- Heating Up in Alberta: Climate Change, Energy Development and Water (2009);
- Carbon Capture and Storage in Canada: CCS and Canada’s Climate Strategy (2009);
- The Pembina Institute’s Perspective on Carbon Capture and Storage (2009);
- Climate Leadership, Economic Prosperity: Final Report on an Economic Study of Greenhouse Gas Targets and Policies for Canada (2009);
- Tailings Plan Review: An Assessment of Oil Sands Company Submissions for Compliance with ERCB Directive 074 (2009);
- Drilling Deeper: The In Situ Oil Sands Report Card (2010);
- Opening the Door to Oil Sands Expansion: The Hidden Environmental Impacts of the Enbridge Northern Gateway Pipeline (2010);
- Northern Lifeblood: Empowering Northern Leaders to Protect the Mackenzie River from Oil Sands Risks (2010);
- Keystone XL in context: oilsands and environmental management (2011);
- Oilsands and climate change: How Canada's oilsands are standing in the way of effective climate action (2011);
- Oilsands Performance Metrics Summary Report (2011);
- Full disclosure: Environmental liabilities in Canada's oilsands: Perspective for investors (2011);
- Solving the Puzzle - Environmental responsibility in oilsands development (2011);
- Pembina Institute’s input on the draft Lower Athabasca Integrated Regional Plan (2011);
- The link between Keystone XL and Canadian oilsands production (2011);
- Developing an environmental monitoring system for Alberta (2011);
- Life cycle assessments of oilsands greenhouse gas emissions (2011);

- Pipeline and tanker trouble - The impact to British Columbia's communities, rivers, and Pacific coastline from tar sands oil transport (2011);
- Responsible Action - An assessment of Alberta's greenhouse gas policies (2011);
- Backgrounder: EU fuel-quality directive. Reducing greenhouse gas emissions through transportation fuel policy (2012);
- In the Shadow of the Boom - How oilsands development is reshaping Canada's economy (2012);
- Backgrounder: Lower Athabasca Regional Plan (LARP) performance backgrounder (2012);
- Beneath the Surface: A review of key facts in the oilsands debate (2013);
- Solving the Puzzle Progress Update (2013);
- Forecasting the impacts of oilsands expansion: Measuring the land disturbance, air quality, water use, greenhouse gas emissions, and tailings production associated with each barrel of bitumen production. (2013);
- Losing Ground: why the problem of oilsands tailings waste keeps growing (2013);
- Booms, busts and bitumen: the economic implications of Canadian oilsands development (2013);
- Oilsands expansion, emissions and the Energy East pipeline (2014);
- Measuring oilsands carbon emission intensity (2016);
- Putting a price on carbon pollution across Canada (2017);
- The Right to a Healthy Environment: Documenting the need for environmental rights in Canada. Case Study 3: Regional impacts of oilsands development in northern Alberta (2017);
- Carbon price vintaging of credits in the output-based allocation system (2017);
- Understanding the pros and cons of Alberta's new industrial carbon pricing rules (2017); and

- Prospects for Alberta oil and gas in a decarbonizing world (2018).

B NATURE AND SCOPE OF OSEC'S INTENDED PARTICIPATION

10. OSEC intends to participate in this hearing by:

a) examining the witness panels of Teck, the Government of Alberta (if they are in attendance at the hearing), the Government of Canada and it reserves its right to ask questions of other witnesses as necessary;

b) presenting an expert witness panel responding to Teck's application and the issues described herein (Sections E through H of this submission); and

c) making final argument.

11. Four of Pembina's in-house experts will provide expert opinion testimony. They are Jan Gorski, Jodi McNeill, Nina Lothian and Simon Dyer. The *curricula vitae* of Mr. Gorski, Ms. McNeill, Ms. Lothian and Mr. Dyer are appended at Tabs 3, 5, 6 and 8, respectively, of the Appendices to this submission. The written report of Mr. Gorski with respect to GHG emissions from the Project is found at Tab 4. The written report of Ms. McNeill and Ms. Lothian with respect to reclamation liability and financial security options for the Project is found at Tab 7. The evidence of Mr. Dyer is found at section H of this submission.

12. In addition to Pembina's in-house experts providing expert opinion evidence, Dr. Chris Joseph, MRM PhD, will provide expert opinion testimony on behalf of OSEC, to speak to matters set out in section E of this submission. Dr. Joseph's *curriculum vitae* is appended at Tab 1. His expert report, which contains a Cost Benefit Analysis of the Project is appended at Tab 2.

C REQUESTED DISPOSITION

13. OSEC respectfully requests the Joint Review Panel ("Panel" or "JRP") conclude that:

a) if a cost-benefit analysis is applied by the Panel in assessing whether the Project is in the public interest, it should be concluded the Project will not create economic benefits and hence is not in the public interest;

b) GHG emission costs add to the likelihood the Project will not prove economical to Alberta and Canada hence approval of the Project is not in the public interest;

c) GHG emissions from the Project will be inconsistent with the steps Alberta and Canada will need to take to meet Canada's 2030 and 2050 targets for GHG emissions and therefore the Project is not in the public interest;

d) reclamation liabilities, the risk of reclamation failure and the risk the posting of security to pay for reclamation is so uncertain as to further economically harm the people of Alberta and Canada dictate that the Project is not in the public interest; and

e) the risks to biodiversity posed by the Project and the failure of the Government of Alberta to create a biodiversity management framework under the Lower Athabasca Regional Plan dictate the Project is not in the public interest.

14. In economic terms, externalities such as air pollution, water pollution, GHG emissions and reclamation liabilities are or can be additional costs associated with initiating and sustaining industrial development typically not fully borne by the industry. Environmental impact assessments ("EIAs") generally do not provide a sufficient base of information adequate to support public-interest decision-making and negative externalities are excluded from the EIA process. It is recognized that analytical rigour and completeness is key to EIAs, particularly in the assessment of the costs associated with the environmental (and human health) aspects that would result from the project going ahead.[1]

15. Lack of evaluation of the Project's externalities impedes the ability to determine the "public interest" question: Is the Project expected to provide a net positive contribution to the welfare of society as a whole? Recent oil sands EIA final reports reviewed by the Royal Society of Canada fell short of providing what others deem necessary to allow for an adequately informed determination of whether a given project is in the public interest.[2]

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[1] Pearce, D., G. Atkinson, and S. Mourato. 2006. Cost-Benefit Analysis and the Environment – Recent Developments. Paris: Organisation for Economic Cooperation and Development (OECD); Pierre Gosselin, Steve E. Hrudey, M. Anne Naeth, André Plourde, René T Errien, Glen Van Der Kraak, and Zhenghe Xu, 2010. The Royal Society of Canada Expert Panel: Environmental and Health Impacts of Canada's Oil Sands Industry. Online at: http://www.rsc.ca/documents/expert/RSC%20report%20complete%20secured%209Mb.pdf.

[2] Royal Society of Canada, *Environmental and Health Impacts of Canada's Oil sands Industry,* (Ottawa: 2010)

D CONDITIONS REQUESTED

16. In the event the Panel concludes the proposed Project is in the public interest, OSEC seeks the imposition of the following conditions on an approval, as alternatives to a dismissal of the application:

- Teck must implement, as a minimum, all of the policies, practices, programs, mitigation measures, recommendations and procedures for the protection of the environment included or referred to in the Project Update (June 15, 2015) and information request responses, or as otherwise committed to during the hearing proceeding;
- Prior to commencement of construction of the Project, Teck shall submit a GHG management plan for the Project to the AER for approval which confirms the steps Teck will take to ensure the Project is in the best performing quartile of oil sands producers with respect to GHG emissions intensity. Best-in-class performance would require direct and indirect GHG emissions of less than 28.9 kg CO_2e/bbl in 2026. Further, the GHG management plan must demonstrate how GHG emissions will be reduced by a further 50 percent between 2026 and 2050 consistent with the requirements of each sector according to Canada's mid-century GHG targets;
- Teck shall not commence construction until the *Oil Sands Emissions Limit Act* regulations have been enacted;
- Teck shall not commence construction of the Project if the Government of Alberta's ten year forecast indicates cumulative oil sands GHG emissions will exceed 100 Mt CO_2e/annum at any time in the first five years of that forecast;
- Teck shall submit to the AER for approval a tailings management plan prepared in compliance with AER *Directive 085: Fluid Tailings Management for Oil Sands Mining Projects* at least two years prior to bitumen production;
- Teck shall, prior to bitumen production, submit to the AER for approval a comprehensive economic assessment of feasible active water treatment options that Teck could implement to ensure water release from pit lakes will meet Alberta guidelines for the protection of aquatic life;

- Teck shall, prior to commencing mining operations, submit to the AER for approval a comprehensive economic assessment of terrestrial closure options for landscapes containing fluid tailings which demonstrates how Teck will manage the risks and uncertainties posed by the closure of fluid tailings sites;

- Teck shall continue to meet its commitments with respect to fluid tailings and reclamation regardless of any future regulatory changes that would reduce the regulatory obligations with respect to fluid tailings treatment or reclamation;

- Teck shall post security for closure, remediation and reclamation of the Project in accordance with the full security option of the Mine Financial Security Program;

- Teck shall have its estimates of closure, remediation and reclamation costs in each annual report under the Mine Financial Security Program verified by an independent third-party;

- Teck shall not commence construction of the Project until such time as the Province of Alberta has completed a Biodiversity Management Framework under the Lower Athabasca Regional Plan;

- Teck shall fully comply with the requirements of the Biodiversity Management Framework;

- Teck shall not commence construction of the Project until such time as an approved range plan is completed by the Government of Alberta for the Red Earth caribou range;

- Teck shall fully comply with the requirements of the approved range plan for the Red Earth caribou herd;

- Prior to commencement of construction of the Project, Teck shall submit to the AER for approval a plan for conservation offsets at a mitigation ratio of at least 4:1 to ensure the Project impacts on biodiversity are fully mitigated and the Project will have no net negative impact on biodiversity; and

- All conditions set on the Project shall be binding on any subsequent operator(s) of the Project.

OSEC reserves the right to request additional conditions throughout the hearing and in final submissions.

E COST-BENEFIT ANALYSIS OF THE PROJECT

17. This is the evidence of Dr. Chris Joseph. The *curriculum vitae* of Dr. Joseph is at Tab 1 of the Appendices to this Submission.

18. By way of a brief introduction, Dr. Joseph earned his Doctorate in Resource Management in 2013 from the School of Resource and Environmental Management of Simon Fraser University. He is the Principal of Swift Creek Consulting in Squamish, B.C. Dr. Joseph has consulted for private industry and governments as well as parties involved in the regulatory process for industrial development projects, has instructed relevant courses at Simon Fraser University, and has provided both written and oral expert opinion evidence in proceedings such as the National Energy Board review of the Enbridge Northern Gateway Project and the Minnesota Public Utilities Commission on the Enbridge Line 3 Replacement project, among others.

19. Dr. Joseph's August 22, 2018 Expert Report *Teck Frontier Mine: Review of Economic Benefits and Cost-Benefit Analysis* (the "Joseph Report") is at Tab 2 of the Appendices to this Submission, and Dr. Joseph adopts the Joseph Report as his evidence.

20. The evidence contained in the Joseph Report, which will be highlighted in oral testimony will tend to establish the findings in the following paragraphs 21 to 32. Alberta and Canadian regulatory criteria emphasize project proposals need to demonstrate the project is in the public interest, yet the information Teck presents in its environmental assessment ("EA") application does not provide an accurate or comprehensive answer to the question of whether the Project is in the public interest.

21. Teck states its economic benefit information shows the Project is a net benefit to society. Teck used a method of benefits assessment well-known in the economics profession to be deficient with respect to informing of net benefits. Teck used economic impact analysis based on input-output modeling to assess a subset of economic effects linked to investment. This method ignores constraints in the economy, such as limits to investment capital and the labour supply, and ignores a range of economic effects, such as incremental government burdens and health

costs of pollution. Teck provides much information on the expected adverse effects of the Project in their EA application but does not synthesize this information with respect to the Project's public interest value.

22. Given the Alberta and Canadian EA regulatory frameworks' concern with whether a project is in the public interest, including the *Canadian Environmental Assessment Act, 2012*'s concern with whether a project's significant adverse effects are "justified in the circumstances" (s.31(1)(a)), it is prudent to adopt methods of impact assessment such as Cost-Benefit Analysis ("CBA") that directly explore and inform such questions. CBA is the primary method in economics for assessing a project's net benefits to society, and thus Dr. Joseph applied this method to the Frontier project.[3]

23. CBA is the standard method of project evaluation used around the world to evaluate the net benefits of major projects to society. The method first came into practical use in the 1930s in the United States to address water resource management issues, and by the 1950s much of the theoretical and practical foundation for CBA had been developed. Today, CBA figures prominently in major project evaluations, regulatory impact assessments, and other policy contexts in many countries including Canada, Australia, New Zealand, European Union countries, the United States, Chile, and by the World Bank. CBA is not currently required for EA in Canada or Alberta, though the method has been used in EAs in Canada on various occasions.[4]

24. CBA revolves around the notion the welfare of society is equal to the sum of the welfare of all individuals. The objective of CBA is to identify how a project will affect peoples' welfare and to aggregate all these effects to indicate whether a project creates a net gain or loss in social welfare.[5]

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[3] Chris Joseph, *Teck Frontier Mine: Review of Economic Benefits and Cost Benefit Analysis*, (22 August 2018), Vol. I, Tab 2, of Submission, at 3.

[4] *Ibid*, at 10-11.

[5] *Ibid*, at 11.

25. Dr. Joseph assessed the value of the Project to society and to private investors (Table ES-1 in the Joseph Report). He focused his analysis on the following benefits and costs:

- revenues from oil production;[6]
- construction, operations, and reclamation costs;[7]
- potential employment benefits;[8]
- costs to government;[9]
- impacts on other commercial activities;[10]
- air pollution;[11]
- GHG emissions;[12]
- impacts on water resources;[13] and
- impacts on ecosystem services.[14]

26. Dr. Joseph's analysis found under base case assumptions the Project will be a net loss to society of $4.6 billion (net present value) and also a net loss to investors with an internal rate of return of 7.8 per cent (Table ES-1).[15]

27. Dr. Joseph concluded little if any employment benefits should be expected from the Project due to current and expected labour market conditions, and as such the Project has little if any public interest value from the perspective of jobs.[16] Several adverse impacts are not captured

[6] *Ibid*, at 14-17.
[7] *Ibid*, at 17-20.
[8] *Ibid*, at 20-22.
[9] *Ibid*, at 23.
[10] *Ibid*, at 23-24.
[11] *Ibid*, at 24-28.
[12] *Ibid*, at 28-31.
[13] *Ibid*, at 31-33.
[14] *Ibid*, at 33-36.
[15] *Ibid*, at 38-39.
[16] *Ibid*, at 21-22.

in his CBA due to technical or philosophical reasons, suggesting his results overestimate the Project's value to society.[17]

28. There are numerous uncertainties in any modeling of a project's future social and private value, yet Dr. Joseph's sensitivity analysis suggests the Project will be a net social loss under a range of scenarios. He tested 17 different scenarios including scenarios in which oil prices, environment damage costs, Project costs, discount rates and approaches, and labour market assumptions were varied. Only four scenarios yielded a positive net social benefit: ignoring GHG damages outside of Canada; the adoption of three per cent and eight per cent uniform discount rates applied to all impacts; and the adoption of the International Energy Agency's *New Policies* oil price forecast. There are reasons to doubt the appropriateness and/or realism of these scenarios given that: it is standard practice to consider the global damages of GHG emissions and not just those occurring within a jurisdiction; a three per cent discount rate is not consistent with private investor expectations; an eight per cent discount rate is not appropriate for long-term environmental impacts; and the International Energy Agency's oil price forecast is unlikely given global climate change concerns, likely future carbon policy, and technological change.[18]

29. Regardless, from a private investor perspective, Dr. Joseph found the Project would be a relatively poor investment earning only a 7.8 per cent internal rate of return under base case conditions and would only provide a reasonable return in four of the 17 scenarios he tested. He feels each of these four higher-return scenarios – in which there would be incremental employment benefits, Project operational and capital costs would be low, or high oil prices would be realized – are not likely. Thus, his findings support the conclusions of both the National Energy Board and the International Energy Agency that new bitumen mines are unlikely to be built.[19]

30. From a distributional standpoint, Dr. Joseph's model suggests the Project is a gain only to the Alberta and federal governments. For investors, the Project is a loss, and for citizens of Alberta, Canada, and beyond, the Project is a loss due to environmental impacts.[20]

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[17] *Ibid*, at 56.

[18] *Ibid*, at 56.

[19] *Ibid*.

[20] *Ibid*, at 57.

31. While Aboriginal groups in the region may experience some employment benefits with the Project, Dr. Joseph opines few economic benefits should be expected without concrete commitments by Teck in the form of contractual obligations contained in an impact-benefit agreement. Regardless, he expects the Project will affect Aboriginal groups through its contribution to the cumulative effects of other development in the region, further compromising not just the landscape and water but the cultural and social activities that depend on them.[21]

32. Dr. Joseph's findings challenge Teck's message of billions of dollars in benefits to governments, businesses, workers, and households. His overall finding is the Project is not in the public interest as it is likely to be a net loss to society and a poor private investment. Even if the Project was developed, workers have at least equal opportunities elsewhere. These conclusions, on top of the Project's substantial environmental impacts, call into serious question whether this Project is in the public interest.

F GREENHOUSE GAS EMISSIONS OF THE PROJECT

33. This is the evidence of Jan Gorski. Mr. Gorski's *curriculum vitae* is at Tab 3 of the Appendices to this submission.

34. A brief summary of Mr. Gorski's qualifications is as follows:

- Bachelor's degree in Aerospace Engineering and a Master's degree in Mechanical Engineering in experimental combustion research;
- Contributor to the development of methane regulations across Canada;
- Led domestic and international projects to measure emissions, conducted emissions inventories, developed new emissions measurement systems, and assessed new technologies to reduce emissions and other environmental impacts from upstream oil and gas developments;
- Field coordination, technical analysis, and report preparation for measurement of fugitive emissions from tailings ponds, mines and other sources at Canadian oil sands facilities; and

[21] *Ibid*.

- Field measurement of GHG emissions from fired equipment in the upstream oil and gas industry.

35. Mr. Gorski's report, *Frontier Oil Sands Mine Project: Review of greenhouse gas emissions and climate change commitments* ("*GHG Report*"), is at Tab 4 of the Appendices, and is adopted by Mr. Gorski as his evidence in this proceeding.

I Teck has underestimated the GHG emissions from the Project.

36. Based on Teck's estimates in the Project Update, the indirect GHG emissions resulting from the Project are expected to total 11,183 t CO2e/day. Teck's estimation of GHG emissions from the Project excludes upstream emissions from the production of natural gas and diesel fuels used on site, as well as GHG emissions resulting from land use changes related to the Project.[22]

37. Emissions from the upstream production of natural gas and diesel fuels used on site and land use changes total 5,343 t CO_2e/day, or an additional 48 percent above Teck's GHG emission estimate (Figure 1).[23]

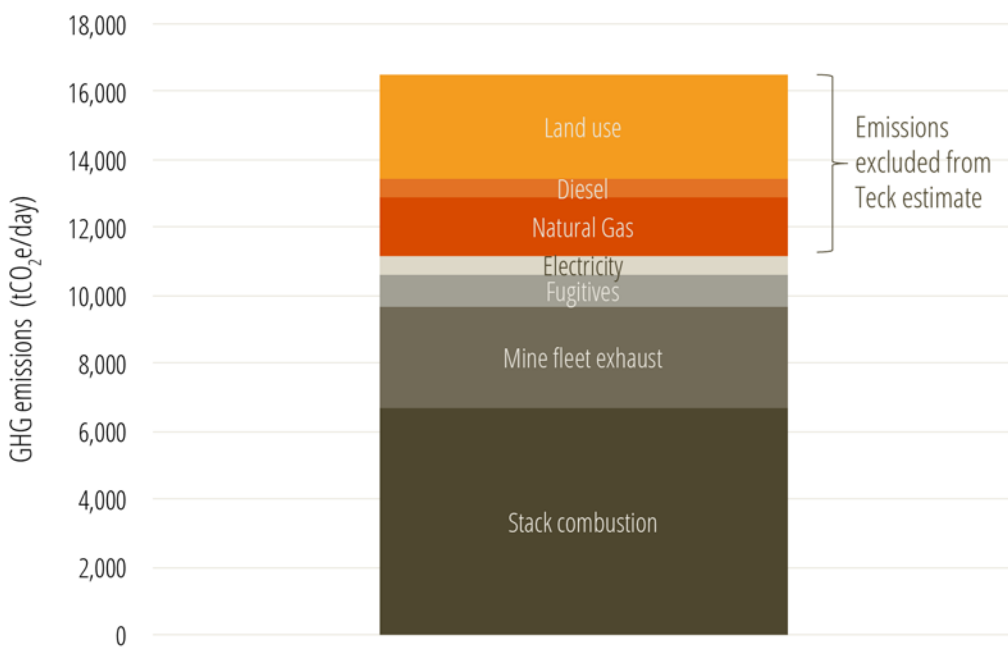

Figure 1. Teck Frontier direct and indirect upstream GHG emissions

[22] Jan Gorski, *Teck Frontier Mine: Review of greenhouse gas emissions and climate change commitments*, (Edmonton: Pembina Institute, 2018), Vol. I, Tab 4, at 2.

[23] *Ibid.*

38. These indirect emissions should be considered when determining the climate impacts of the Project, especially in relation to provincial and national GHG emission targets.[24]

II The Project's GHG emissions intensity will not be best-in-class.

39. Teck has estimated the GHG emission intensity for the Project to be 38.4 kg CO_2e/bbl for direct emissions and 40.4 kg CO_2e/bbl for direct and indirect emissions. A comparison of this emissions intensity against other oil sands mining projects using the paraffinic froth treatment process indicates the Project will have a GHG emissions intensity that is 24 percent above the best-in-class project.[25]

40. Further, the Project's GHG emissions intensity will be 40 percent higher than the 2026 *Carbon Competiveness Incentive Regulation* limit of 28.9 kg CO_2e/bbl which is based on the performance of the top-quartile of bitumen mining operations.[26]

41. While the emissions intensity of the Project may be about average for oil sands mining and extraction projects, it is unlikely to achieve the best-in-class standard. New oil sands projects should be required to demonstrate that their GHG emissions intensity is at least as good as the top quartile performers. Alberta and Canada will be unlikely to meet their GHG targets if sub-par projects are allowed to proceed.

III Teck has underestimated the cost of compliance within the 100 Mt GHG limit.

42. Teck states it believes the Project emissions will not exceed the 100 Mt cap and that the cap may not be reached at all depending on how the regulation is structured and how emitters respond. Other sources predict the 100 Mt limit will be reached between 2024 and 2030 (Figure 2). Therefore, there is a risk the Project will have to fit its emissions under the cap either before its start-up date or during its early operating years.[27]

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[24] *Ibid*, at 3.
[25] *Ibid*, at 4-5.
[26] *Ibid*, at 5.
[27] *Ibid*, at 7.

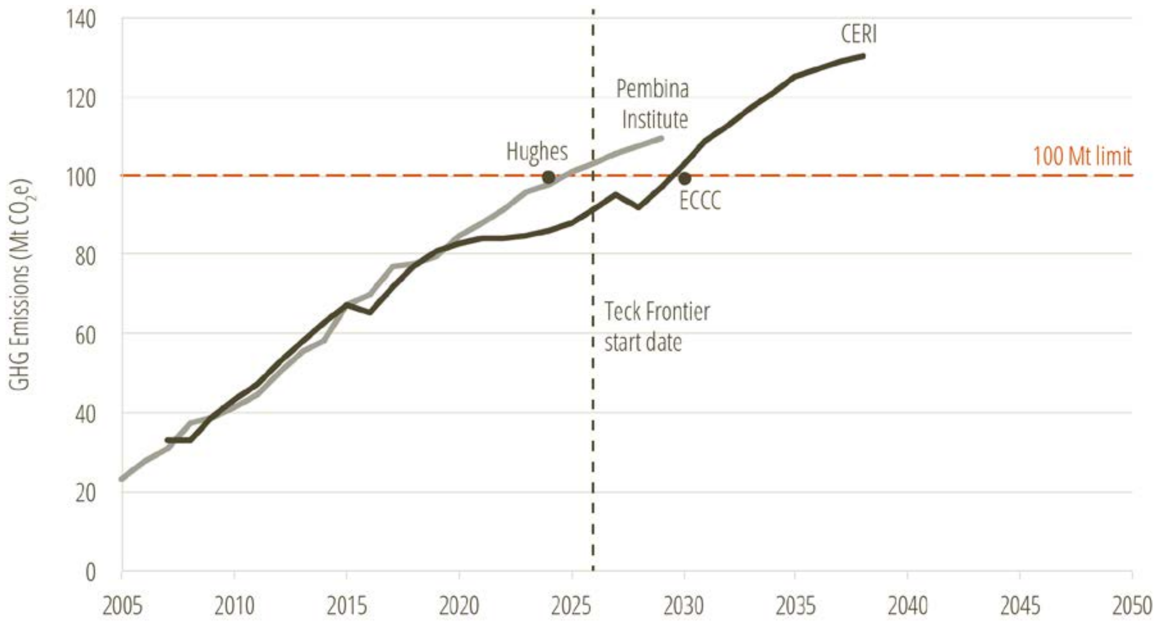

Figure 2: Oil Sands GHG emissions forecasts

43. While the structure of the regulation of the 100 Mt cap is not known at this time, the Oil Sands Advisory Group recommended that once the 100 Mt cap is reached, facilities in the worst two performing quartiles would be required to make emissions reductions. OSAG also recommended the Minister of Energy or Minister of Environment and Parks should have the authority to suspend the project approval of facilities that have not yet started construction if the 100 Mt limit is approached. These actions would be determined based on 10-year forecasts. If a forecast indicates that oil sands emissions are expected to exceed the 100 Mt limit within five years, this would trigger the actions stated above.[28]

44. However, Teck has not made any allowance for the cost of compliance within the 100 Mt cap or the possibility of delay or suspension of the Project due to the limit.[29]

[28] *Ibid*, at 9

[29] *Ibid*, at 10

IV Teck has underestimated the cost of compliance with the Carbon Competitiveness Incentive Regulation

45. Teck has calculated the cost of compliance with the former *Specified Gas Emitters Regulation* ("*SGER*") at $635 million over the life of the Project. This cost underestimates the cost of compliance with the current *Carbon Competitiveness Incentive Regulation* ("*CCIR*").[30]

46. Teck's calculation of cost under the *SGER* assumes a carbon credit price of $30/tonne. The Alberta Climate Leadership Plan anticipates the carbon fund credits rising to $50/tonne in 2022.[31]

47. OSEC has calculated the cost of compliance with the *CCIR* through the purchase of fund credits at $1.9 billion over the life of the Project with a carbon price of $30/tonne, and $3.1 billion with a carbon price of $50/tonne.[32]

V GHG emissions from the Project are inconsistent with Canada's climate targets.

48. In 2015, Canada signed onto the Paris agreement, committing to a 30 percent reduction in GHG emissions from 2005 levels by 2030. Although the oil sands 100 Mt limit forms a firm stop for oil sands emissions growth, the Government of Canada's own projections show both current and planned policies are likely to leave the country 66 Mt short of its Paris target.[33]

49. Looking further into the future, Canada has set a mid-century GHG emissions target of 80 percent below 2005 levels, or a total national GHG emissions target of 150 Mt by 2050. It is not in the realm of possibility the oil sands would be allowed to grow and account for more than two-thirds of Canada's GHG emissions in 2050 while all other sectors of the economy decarbonize.[34]

50. Teck has not accounted for the fact that, in order to meet Canada's mid-century GHG targets, oil sands projects, including the Frontier Project, will be required to significantly reduce their GHG emissions intensity or to curtail production.

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[30] *Ibid*, at 11.
[31] *Ibid*.
[32] *Ibid*.
[33] *Ibid*, at 12.
[34] *Ibid*, at 13.

51. The Project application fails to demonstrate how this will be in line with Canada's mid-century GHG targets, or to propose a plan to reduce GHG emissions by 50% in line with Canada's mid-century GHG targets.

52. If the Project is approved, the federal government must demonstrate how the GHG emissions from the Project will be offset by reductions in GHG emissions in other industrial sectors in order to meet Canada's 2030 and mid-century GHG emission targets.

G RECLAMATION LIABILITIES OF THE PROJECT

53. This is the evidence of Jodi McNeill and Nina Lothian. Ms. McNeill's *curriculum vitae* is at Tab 5 of the Appendices to this submission. Ms. Lothian's *curriculum vitae* is at Tab 6 of the Appendices.

54. A brief summary Ms. McNeill's qualifications is as follows:

- Masters and undergraduate degrees in interdisciplinary programs focusing on the intersections between sustainable development, geography, environmental science, public policy, and resource management;
- Published masters dissertation research focusing on contemporary public engagement with regulatory processes for major Alberta oil sands projects;
- Signatory and co-author of seven statements of concern regarding the Tailings Management Plans ("TMPs") submitted since November 2016 under Alberta's *Directive 085: Fluid Tailings Management for Oil Sands Mining Projects*;
- Participant in Enhanced Review Process for the TMPs for the Suncor Base Plant and Syncrude Aurora North oil sands mines;
- Signatory and co-author of detailed review and comment on the AER's draft conditions of approval for seven TMPs;
- Primary representative of the Pembina Institute and the ENGO caucus at the multi-stakeholder Stakeholder Interest Group concerning the Tailings Management Framework, hosted by the Government of Alberta (2016-current);

- Primary representative of the Pembina Institute and the ENGO caucus at the multi-stakeholder Integrated Water Management Working Group ("IWMWG") concerning the Tailings Management Framework, hosted by the Government of Alberta (2016-2018);

- Deputy representative of the Pembina Institute and the ENGO caucus at the multi-stakeholder Mine Financial Security Program - Tailings Management Framework ("MFSP-TMF") Working Group, hosted by the Government of Alberta (2016-2018);

- Primary representative of the Pembina Institute and the ENGO caucus at the multi-stakeholder Technical Advisory Committee ("TAC") for Tailings Regulatory Management, hosted by the Alberta Energy Regulator (2015-16); and

- Analysis quoted on the subjects of oil sands tailings and liability in media outlets including the Globe and Mail, National Post, Calgary Herald, Canadian Press, and Bloomberg. Op-eds on these subjects published by the Calgary Herald, iPolitics, and THIS magazine.

55. A brief summary of Ms. Lothian's qualifications is as follows:

- Professional engineer with an undergraduate degree in mining engineering;

- Eight-and-a-half years' experience working for an oil sands mining operation in a variety of roles including mine planner, project engineer on a tailings relocation project, project manager for mine projects, cost estimating team leader, and strategic planning advisor; and

- Since joining the Pembina Institute, collaborated with government, industry, Indigenous organizations and other ENGOs on oil sands tailings management. This work included: participation in the Government of Alberta Mine Financial Security Program working group and Tailings Management Framework workshops, participation in the Alberta Energy Regulator's Enhanced Review Process of Suncor and Syncrude Tailings Management Plans, review and submission of statements of concern for each of the seven Tailings Management Plans submitted under Directive 085.

56. Ms. McNeill's and Ms. Lothian's report, *Frontier Oil Sands Mine Project: Review of liability management and financial security options* ("*Liability Report*"), is at Tab 7 of the

Appendices, and is adopted by Ms. McNeill and Ms. Lothian as their evidence in this proceeding.

I Teck has underestimated the reclamation timelines and costs for the Project

57. There is a high likelihood Teck has underestimated the requirements and costs of post-closure monitoring and mitigation for the Project. Teck has proposed an adaptive management approach that will require monitoring of deposit settlement, erosion, vegetation growth, and water quality for decades – or potentially centuries – after the reclamation period ends in 2081. Teck has not provided any detailed contingency plans delineating how it will manage changes to timelines and costs due to poorer-than-anticipated performance of various closure landscape features, real-world seepage patterns and cumulative substance concentrations which differ from modeled projections, and/or any other unforeseen circumstances.[35]

58. Teck repeatedly cites its experience with mining reclamation across a variety of assets as evidence of its ability to carry out closure and reclamation of the Project. While Teck's reclamation experience is valuable, it is imperative to note reclamation in the oil sands mining sector poses unique challenges relative to hard rock and coal mining operations.[36]

59. In the last fifty years of industrial-scale oil sands mining only 0.12 per cent of land disturbed has been certified as reclaimed. The industry claims that 6.5 per cent of land has been permanently reclaimed, but this land has not yet met regulatory requirements for certification. Further, no oil sands operator has successfully reclaimed a fluid tailings site. Teck has failed to account for the challenges of oil sands reclamation in its reclamation timelines and cost estimates.[37]

II Teck's reliance on it diversified assets to cover reclamation costs and security is unfounded.

60. Teck raises its diversified portfolio of operations as a means to ensure financial security for the closure and reclamation of the Project. However, this brings into question the viability of the Project as a stand alone enterprise. Despite requests to do so, Teck has not provided a

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[35] Jodi McNeill and Nina Lothian, *Teck Frontier Mine: Review of liability management and financial security options*, (Edmonton: Pembina Institute, 2018) Vol. I, Tab 7, at 4-9

[36] *Ibid*, at 9-10.

[37] *Ibid*, at 10.

comparison of closure liability to posted security or revenue over the life of the Project or identified specific sources of funds for security.[38]

61. This information gap is highly relevant to the review of the Project because, while it is reasonable to anticipate Teck may need to use cash flows from its other assets to provide financial security for the Project at the outset, the Project itself must be able to provide security over its life. If this is not possible, it raises serious concerns as to the economic viability of the project.[39]

62. Further, reliance on other Teck assets to provide security for the closure and reclamation of the Project assumes that:

a) the other corporate entities continue to operate in a profitable manner;

b) revenue from the other corporate entities is surplus to that needed to close and reclaim those other properties; and

c) the Project is not sold to another operator with a less diverse portfolio of assets.[40]

63. For these reasons, other assets in Teck's corporate portfolio should not be considered by the Panel in assessing Teck's ability to meet its closure and reclamation obligations.

III Teck's reliance on the Mine Financial Security Program will not provide adequate security for closure and reclamation.

64. Teck's stated preference is for a liability management approach that follows the current Mine Financial Security Program ("MFSP"). However, the MFSP as it exists today fundamentally misrepresents the liability risk to the Crown incurred by oil sands mines and improperly transfers significant public liability to future generations of Albertans.[41]

65. The MFSP underestimates the liabilities associated with an oil sands project. Further, the MFSP's reliance on undeveloped oil sands resources as assets is unfounded. If an existing

[38] *Ibid*, at 12.
[39] *Ibid*.
[40] *Ibid*, at 13.
[41] *Ibid*, at 14.

operator is unable to complete extraction of their reserves for economic reasons, it is unlikely the province or another operator will be able to do so viably either.[42]

66. Only a full security option under the MFSP, based on realistic third-party costs for closure and reclamation, will protect the Alberta taxpayer from financial risks. Therefore, OSEC recommends the full security option under the MFSP be set as a condition of approval of the Project.[43]

H BIODIVERSITY IMPACTS OF THE PROJECT

67. This is the evidence of Simon Dyer. Mr. Dyer's *curriculum vitae* is at Tab 8 of the Appendices to this submission.

68. A brief summary of Mr. Dyer's qualifications is as follows:

- Masters and undergraduate degrees in natural sciences, specialization in Zoology (University of Cambridge) and Environmental Biology and Ecology (University of Alberta);
- Published masters dissertation research focusing on impact of industrial developments on movement and distribution of woodland caribou;
- Member of the Sustainable Ecosystems Working Group of the Cumulative Environmental Management Association that developed the Terrestrial Ecosystem Management Framework that informed the Lower Athabasca Regional Plan (2005-2008);
- Appointed to the Oil Sands Advisory Group by Minister of Environment and Parks (2016-2018);
- Author of over 40 publications on environmental impacts of energy development from 2006 to 2018;
- In 2013, Mr. Dyer was awarded the Queen Elizabeth II Diamond Jubilee Medal for his work to support environmentally responsible energy development in Alberta and Canada;

[42] *Ibid*, at x16

[43] *Ibid*, at 18.

- Board member of the Alberta Biodiversity Monitoring Institute since 2007, and Vice chair from 2016 – present; and
- Registered Professional Biologist from 2000 – present.

69. In OSEC's original statement of concern, submitted on June 4, 2012, OSEC argued the Project should not proceed until thresholds had been established to manage cumulative effects under the Lower Athabasca Regional Plan ("LARP").[44] While LARP was released in August 2012, biodiversity management frameworks have not been completed which precludes responsible decision-making under a cumulative effects management approach.

70. The Regional Sustainable Development Strategy ("RSDS") was released in 1999. It promised biodiversity objectives for management of the oil sands would be completed in two years.[45] OSEC member organizations participated in good faith for many years to help the government advance this work as a member of CEMA and through participation in land use planning processes.

71. Nineteen years later, Alberta and Canada are no closer to managing the cumulative impacts of projects in the oil sands for biodiversity or setting objectives for acceptable impacts on biodiversity values.

72. The Project has similar impacts and commits to similar inadequate mitigation of impacts to biodiversity as the Shell Jackpine Expansion project. Teck suggests that it <u>may</u> consider conservation offsets to mitigate impacts but makes no commitment to do so. The Joint Review Panel, in its decision report for the Shell Jackpine Expansion project concluded that:

> *(9) The Panel finds that the Project would likely have significant adverse environmental effects on wetlands, traditional plant potential areas, wetland-reliant species at risk, migratory birds that are wetland-reliant or species at risk, and biodiversity. There is also a lack of proposed mitigation measures that have been proven to be effective. The Panel also concludes that the Project, in combination with other existing, approved, and planned projects, would likely have significant adverse cumulative environmental effects on wetlands; traditional plant potential areas; old-growth forests; wetland-reliant species at risk and migratory birds; old-growth forest reliant species at risk and migratory*

[44] Oil Sands Environmental Coalition, Statement of Concern re Teck Resources Limited Frontier Oil Sands Mine Project (4 June 2012) at 5.

[45] Alberta Environment, *Regional Sustainable Development Strategy for the Athabasca Oil Sands Area,* (Edmonton: 1999) at 23.

birds; caribou; biodiversity; and Aboriginal traditional land use (TLU), rights, and culture. Further, there is a lack of proposed mitigation measures that have proven to be effective with respect to identified significant adverse cumulative environmental effects.

(14) The Panel also believes that the Lower Athabasca Regional Plan (LARP), although still a work in progress, is an appropriate mechanism for identifying and managing regional cumulative effects, including the proposed biodiversity management framework and new Alberta wetlands policy (both in development). The LARP is an excellent and important framework for beginning to introduce a more integrated regional approach, and the Panel strongly encourages Alberta to continue to implement this regional plan. It is critical that the frameworks, plans, and thresholds identified in the LARP be put in place as quickly as possible. Future project reviews will benefit greatly from the completion of this regional approach.

(31) …Although the Panel recognizes that LARP and other regulations and policies of the government of Alberta do not currently mandate the use of conservation offsets in the oil sands region, given that there are few options available for avoiding or minimizing the adverse effects of large surface mines, the Panel believes that the use of conservation offsets may be necessary.[46]

73. All these findings apply, and are more urgent with respect to the proposed Teck Frontier project. The biodiversity management framework must be in place and Teck must commit to conservation offsets before the Project proceeds.

74. The LARP stated:

A new biodiversity management framework for the Lower Athabasca Region on public land in the Green Area and provincial parks will bring context to these efforts [to protect and manage biodiversity] at the regional level. The framework will be developed by the end of 2013 and will:

- Set targets for selected biodiversity indicators (vegetation, aquatic and wildlife); and
- Address caribou habitat needs in alignment with provincial caribou policy.[47]

[46] Joint Review Panel for the Jackpine Mine Expansion Project, *Report of the Joint Review Panel, Shell Canada Energy Jackpine Mine Expansion Project*, 2013 ABAER 011, at paras 9, 14, 31.

[47] Government of Alberta, *Lower Athabasca Regional Plan, 2012-2022* (Edmonton: 2012), at 28.

75. Alberta has not completed Biodiversity Management Frameworks contrary to the requirement in LARP. As such it is not possible for the Panel to responsibly determine if the Project has acceptable impacts on biodiversity. This continued failure represents 19 years of delay and obfuscation on this issue.

76. Woodland caribou from the Red Earth range have been documented using the proposed Project site. Alberta was required to have completed range plans for Woodland Caribou by October 2017, five years after the release of the Recovery Strategy for Woodland Caribou.[48] A range plan for the Red Earth herd that meets the 65 per cent undisturbed habitat threshold required by the federal *Species at Risk Act* has not been completed.

77. It is not acceptable Alberta continues to miss legal deadlines to protect caribou and ignore the direction of previous panels that management frameworks for biodiversity are implemented. As such, OSEC makes the following recommendations with respect to biodiversity and caribou:

(a) OSEC recommends the Project be rejected, or approval is conditional on Alberta completing the LARP Biodiversity Management Frameworks and Red Earth caribou range plan;

(b) OSEC recommends the Panel, in strongest possible terms, sanction Alberta for its failure to implement biodiversity and caribou management frameworks and plans, which are necessary to support responsible decision-making; and

(c) OSEC recommends if the Project is recommended for approval, the Panel include conditions that, at a minimum require there is a no net impact on biodiversity through a mandatory requirement for conservation offset actions, at a mitigation ratio of at least 4:1, to ensure Project impacts are fully mitigated.

I CONCLUSIONS

78. In summary, OSEC submits the Project is not in the public interest and should not be approved.

[48] Environment Canada, *Recovery Strategy for the Woodland Caribou (Rangifer tarandus caribou), Boreal population, in Canada* (Ottawa: 2012) at 38-39.

79. On a cost-benefit analysis, the Project is a net loss to Albertans and Canadians when environmental costs are considered. The costs of GHG emissions, when internalized, render the Project uneconomic. Further, the GHG emissions from the Project are inconsistent with the significant GHG emission reductions that are required for Canada to meet its 2030 and 2050 GHG emission targets.

80. Teck's closure and reclamation plans call for monitoring and possible mitigation measures for decades and possibly centuries beyond the end of mine life. These monitoring and mitigation costs are not accurately represented in the costs of the Project. Further, Teck's planned reliance on the Mine Financial Security Program leaves Albertans at risk for reclamation liabilities.

81. Alberta's ongoing failure to produce a Biodiversity Management Framework under the Lower Athabasca Regional Plan and failure to produce a range plan for the Red Earth caribou range, leaves caribou and other species unprotected from Project development.

82. In terms of cumulative impacts, the Panel does not have adequate evidence to demonstrate the cumulative impacts from the Project are sustainable or acceptable. OSEC urges the Panel to find the Project has significant adverse environmental impacts, to recommend those impacts are not justified in the circumstances, and to recommend against approval of the Project.

ALL OF WHICH IS RESPECTFULLY SUBMITTED this 31st Day of August, 2018

Kurt Stilwell	Barry Robinson
Kurt Stilwell	Barry Robinson
Barrister and Solicitor	Barrister and Solicitor
Counsel for Oil Sands Environmental Coalition	Counsel for Oil Sands Environmental Coalition

LIST OF APPENDICES

TAB	DOCUMENT
Vol. I	APPENDICES TO WRITTEN SUBMISSION
1	*Curriculum vitae* of Dr. Chris Joseph
2	Report of Dr. Chris Joseph: *Teck Frontier Mine: Review of Economic Benefits and Cost-Benefit Analysis*
3	*Curriculum vitae* of Jan Gorski
4	Report of Jan Gorski: *Frontier Oil Sands Mine Project: Review of greenhouse gas emissions*
5	*Curriculum vitae* of Jodi McNeill
6	*Curriculum vitae* of Nina Lothian
7	Report of Jodi McNeill and Nina Lothian: *Frontier Oil Sands Mine Project: Review of liability management and financial security options*
8	*Curriculum vitae* of Simon Dyer
Vol. II	SELECTED REFERENCES
A	**Selected References from *Frontier Oil Sands Mine Project: Review of greenhouse gas emissions and climate change commitments***
1	Environment and Climate Change Canada, *National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada*, (Ottawa: 2018)
2	Government of Alberta, “Standard for Establishing and Assigning Benchmarks V2.1 Carbon Competitiveness Incentive Regulation,” (Edmonton: June 2018)
3	Government of Alberta, “Total Oil Sands Production”, accessed online at: http://osip.alberta.ca/library/Dataset/Details/46

4	Government of Alberta, "Capping oil sands emissions," accessed online at: https://www.alberta.ca/climate-oilsands-emissions.aspx (15 August 2018)
5	Excerpt from J. David Hughes, *Canada's Energy Outlook: Current Realities and Implications for a Carbon-Constrained Future*, (Vancouver: Canadian Centre for Policy Alternatives, 2018)
6	Dinara Millington, *Canadian Oil Sands Supply Costs and Development Projects (2018-2038)*, Study No. 170 (Calgary: Canadian Energy Research Institute, 2018)
7	Experience Nduagu, *Economic Potentials and Efficiencies of Oil Sands Operations: Processes and Technologies*, Study No. 164 (Calgary: Canadian Energy Research Institute, 2017)
8	Oil Sands Advisory Group, "Recommendations on Implementation of the Oil Sands Emissions Limit Established by the Alberta Climate Leadership Plan ("ACLP")", (Edmonton: May 8, 2017)
9	Environment and Climate Change Canada, *Technical Paper on the Federal Carbon Pricing Backstop*, (Gatineau: 2017)
10	Environment and Climate Change Canada, *Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy*, (Gatineau: 2016)
11	Environment and Climate Change Canada, *Canada's Seventh National Communication on Climate Change and Third Biennial Report*, (Gatineau: 2017)
12	Environment and Climate Change Canada, *Progress towards Canada's greenhouse gas emissions reduction target*, (Gatineau: 2018)
13	Sonia Yeh et al, "Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands," (2010) 44 Enviro. Sci. Tech
14	Statistics Canada, *Report on Energy Supply and Demand in Canada, 2016 Preliminary* (Ottawa, 2018)
B	**Selected references from Frontier *Oil Sands Mine Project: Review of liability management and financial security options***
15	Dalmia, Avinash, "Analysis of naphthenic acids in filtered oil sands process water (OSPW) using LC/TOF with no sample preparation" (2013) Perkin Elmer: Application Note

16	Grewer DM et al., “Naphthenic acids and other acid-extractables in water samples from Alberta: What is being measured?” (2010) Science of the Total Environment. doi:10.1016/j.scitotenv.2010.08.013
17	Alberta Environment and Parks, Oil Sands Information Portal, “Regional Totals for Reclamation and Disturbance Tracking, by Year” (2016), online at http://osip.alberta.ca/library/Dataset/Details/27
18	Auditor General of British Columbia, *An Audit of Compliance and Enforcement of the Mining Sector*, (Victoria: 2016)
19	Auditor General of Alberta, *Report of the Auditor General of Alberta*, (Edmonton: July 2015)
20	Alberta Energy Regulator, “Mine Financial Security Program – Security and Liability”, (Calgary: September 2017)
21	Branko Bošković and Andrew Leach, “Leave It in the Ground? Incorporating the Social Cost of Carbon into Oil Sands Development”, (2017) University of Alberta School of Business Research Paper No. 2920341.
22	Excerpt from Canada’s Ecofiscal Commission, *Responsible Risk: How putting a price on environmental risk makes disasters less likely*, (Ottawa: 2018).
C	**Selected references from submissions of Simon Dyer**
23	Alberta Environment, *Regional Sustainable Development Strategy for the Athabasca Oil Sands Area*, (Edmonton: 1999)
24	Joint Review Panel for the Jackpine Mine Expansion Project, *Report of the Joint Review Panel, Shell Canada Energy Jackpine Mine Expansion Project*, 2013 ABAER 011
25	Government of Alberta, *Lower Athabasca Regional Plan, 2012-2022* (Edmonton: 2012)
26	Environment Canada, *Recovery Strategy for the Woodland Caribou (Rangifer tarandus caribou), Boreal population, in Canada* (Ottawa: 2012)

TAB 1

Chris Joseph MRM, PhD

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cjoseph@swiftcreekconsulting.com; 604-848-9804; www.swiftcreekconsulting.com

Expertise and Skillsets

- environmental assessment including the assessment of economic impacts, the impacts of energy development, and the theory of environmental assessment and cumulative effects
- environmental and ecological economics, including cost-benefit analysis and non-market valuation
- megaproject development and their valuation
- collaborative planning, multi-stakeholder engagement, and facilitation
- policy evaluation and policy implementation
- literature synthesis and surveying/questionnaires
- structured decision-making
- project management and group leadership
- instruction and communications

Education

PhD (Resource Management), 2006 - 2013
School of Resource and Environmental Management. Simon Fraser University
"Megaproject Review in the Megaprogram Context: Examining Alberta Bitumen Development"
Recipient of several scholarships and awards, including Canada Graduate Scholarship – Doctoral (SSHRC) 2006-2009

Masters of Resource Management, 2002 - 2004
School of Resource and Environmental Management. Simon Fraser University
"Evaluation of the B.C. Strategic Land-Use Plan Implementation Framework"

Bachelor of Science (Honours with Distinction; Geography), 1993 - 1998
University of Victoria
"The Impact of Rock Climbing on the Soils and Vegetation at the Base of Cliffs within Greater Victoria, British Columbia"

Professional Affiliations

International Association of Impact Assessment

International Association of Impact Assessment – Western and Northern Canada

Past membership with the Association of Professional Economists of BC, International Association of Energy Economics, the Planning Institute of BC, Canadian Institute of Planners, and Connecting Environmental Professionals

Summary of Professional Experience

2016 - present
Principal, Swift Creek Consulting, Squamish, BC

2016 – 2018
Senior Socio-economic Specialist, SNC Lavalin, Vancouver BC

2003 – 2017
Sessional Instructor and Teaching Assistant, SFU, Burnaby BC
Courses: REM 321 Ecological Economics, REM 356 Resource Management Institutions, GEOG 389 Political Ecology, HSCI 845 Occupational and Environmental Health

2010 - 2016
Associate, Compass Resource Management, Vancouver BC

2000 - Present
Owner, Chris Joseph Photography, Squamish BC
Photography and writing published in national and international publications, websites, and catalogues including Globe and Mail, Patagonia, Explore, Climbing, BC Paraplegic Association, Canada Science and Technology Museum, British Columbia Magazine, Mountain Equipment Co-op, Readers Digest, Ski Canada, Pique, Vancouver Sun, Westworld (BCAA), and National Post.

2003 - 2013
Researcher, Sustainable Planning Research Group, SFU, Burnaby BC

2005 – 2009
Independent Consultant, Vancouver BC

2005 – 2006
Research Associate, MK Jaccard & Associates, Canadian Industrial Energy End-Use Data and Analysis Centre, Vancouver BC

2004 – 2005
Assistant, Melting Mountains Awareness Program (David Suzuki Foundation / Alpine Club of Canada / Environment Canada), Vancouver BC

2000 – 2001
Project Supervisor, Outland Reforestation, Toronto / Thunder Bay ON

Past Assignments

West Moberly First Nations: Impacts of a Suspension of the Site C Project on Construction Workers and Municipalities. Wrote expert testimony to inform the court with respect to an application for injunction with regards to how suspension of the project may affect current construction workers and municipalities in the region. (May 2018)

Indian and Northern Affairs Canada: Technical Review of Socio-economic Impact Assessment of the proposed Hope Bay Phase 2 Mine. Team lead of SNC Lavalin's technical review of socio-economic material in the final environmental impact statement of TMAC Resources' proposed Hope Bay Phase 2 mine in Nunavut. Review included reviewing regulatory and proponent documentation and advising INAC on appropriate responses. (Winter and Spring 2018)

BC Parks: Development of Living Labs climate change research framework. Developed a funding framework for climate change research in BC parks and protected areas. Work included developing a database of recent climate change research in BC Parks through literature review and survey, a database of potential research and funding partners, and facilitating sessions at a meeting with BC government staff. Oversaw two subcontractors in this work. (Fall 2017-Spring 2018)

BC MFLNRO: Socio-economic profiles and scenario development – Caribou Range Planning in NE BC. Subcontracted to Green Analytics. Developed scenarios of forestry and gas development, and provided strategic advice. (Spring 2018)

Alberta Environment and Parks: Advice on Improved Integration of Project-level Environmental Impact Assessment and Regional Cumulative Effects Management. Reviewed existing linkages between project-level EIA in the South Athabasca Oil Sands area with regional cumulative effects management, including through expert interviews. Provided recommendations to improve the contribution of project-level EIA to regional cumulative effects management. (Fall 2017 – Spring 2018)

Environmental Law and Policy Center (USA): Assessment of the need for the Enbridge Line 3 Replacement Program. Provided written and in-person expert testimony of the need for the Enbridge L3R project, including an assessment of supply and demand of oil transport capacity, costs to Minnesota, and economic benefits of the project. (Fall 2017)

Centremount Coal: Socio-economic lead for SNC Lavalin's environmental assessment of the proposed Bingay coal mine. Scoping, baseline, and impact assessment studies of potential social, economic, and community health effects of the proposed Bingay coal mine in south-east BC. (2016-2018)

Pacific Future Energy: Socio-economic lead for SNC Lavalin's environmental assessment of the proposed Pacific Future Energy green refinery. Scoping and baseline studies of potential social, economic, and community health effects of the proposed green refinery in north-west BC. Advising to proponent on Aboriginal engagement, and engagement with Kitselas First Nation representatives. (2016-2017)

Gitga'at First Nation: Environmental assessment advisor. Since 2013, on an as-needed basis, provided advice to the Gitga'at First Nation regarding EA applications and processes, generally pertaining to socio-economic topics. Assignments included critiquing proponent EA applications, preparing Information Request submissions to EA bodies, and examining issues in EA application content and methodology with proponent consultants. (2013-2017)

Ng Ariss Fong: Assessment of the economic impacts of the Nathan E. Stewart tug spill on the Heiltsuk First Nation. Supported First Nation's legal claim against shipping company by gathering quantitative data, interviewing community representatives and members regarding traditional and commercial harvests, and estimating monetary impact of spill on Heiltsuk harvests. (2016)

Stk'emlupsemc te Secwepemc First Nation: Economic Review of Ajax Mine. Critiqued environmental assessment application of the KGHM Ajax mine project in Kamloops, BC with respect to economic impacts and value of the project. Conducted a multiple-accounts cost-benefit analysis of the project. Identified potential additional mitigation measures. Testified to the Nation's environmental assessment review panel. (2016)

International Pacific Halibut Commission: Facilitation of Management Strategy Evaluation workshops and design of outreach strategy. Over 2015 and 2016 designed and facilitated meetings for Management Strategy Advisory Board in support of their management strategy evaluation (a collaborative analysis of optimal fishery management actions). Also supervised the development of an outreach strategy for the board. (2015-2016)

Hemmera / Yukon Energy: Stakeholder engagement, meeting facilitation, and options assessment pertaining to the mitigation of impacts of the Southern Lakes Storage Enhancement Concept. Designed and facilitated two rounds of engagement with stakeholders regarding their preferences for erosion mitigation, including small and large group meetings. Conducted options assessment with engineering team (NHC) and explored options collaboratively with stakeholders. (2015)

Tsawout First Nation, Upper Nicola Band, Living Oceans Society: Public Interest Evaluation of the Kinder Morgan Trans Mountain Expansion Project. Contributing editor. Deliverable included an evaluation of Kinder Morgan's economic impact assessment of their proposed Trans Mountain Expansion Project and a cost-benefit analysis of the project. (2015)

Instream Fisheries Research: Facilitation of Gates Creek Sockeye Workshop. Designed and facilitated workshop focused on bringing together the variety of scientists and Aboriginal knowledge-holders, finding research gaps, and identifying steps forward with respect to information gathering, collaboration, and support of management. (2015)

Gitga'at First Nation: Impact Assessment of Prince Rupert LNG Projects. Led a two-person team and was the lead analyst in screening-level analyses of potential socio-economic impacts of three LNG projects (Prince Rupert LNG, Aurora LNG, Pacific Northwest LNG) and a detailed economic impact assessment of the Kitimat LNG project. Examined issues including: economic opportunities including jobs and contracts, access to goods and services, housing, human resources in remote communities, social cohesion, commercial fishing, tourism, carbon offsets, and economic development. Also supervised the writing of a baseline data report to help proponents fill their data gaps. (2014)

Metlakatla First Nation: Assessment of potential impacts of LNG development. Led a six-person team including subcontractor, and was lead analyst, examining the potential impacts of the Pacific Northwest LNG, Prince Rupert LNG, Westcoast Connector LNG pipeline, and Prince Rupert Gas Transmission LNG pipeline projects). Identified seven valued components through document review, interviews, and community workshop. Topic matter covered the economic, health, heritage, and social pillars. Developed baselines and gathered data for proponents. Developed a spreadsheet-based database and model to examine cumulative effects. Assessed the effects of projects in the context of cumulative effects of other development and stresses. Conducted a final workshop with community representatives to validate draft results. Researched mitigation opportunities. Developed a plain language summary for client in addition to detailed report. (2013-2014)

Gitga'at First Nation: Assessment of the potential economic impacts of LNG Canada project. Led a three-person team, and was the lead analyst. Identified six economic valued components through document review and interviews. Developed baselines. Developed a spreadsheet-based database and model to examine cumulative effects. Assessed the effects of projects in the context of cumulative effects of other development and stresses. Researched mitigation opportunities. Conducted a workshop with community representatives to validate draft results. (2013-2014)

Canadian Oil Sands Innovation Alliance: Structuring and gathering thinking on innovations in oil sands mine reclamation. Worked with two other firms on a multiple component project that gathered knowledge across oil sands mining companies on how to reclaim watersheds and to identify research priorities. (2013)

BC Ministry of Forests, Lands, and Natural Resources Operations: Recommendations for a Provincial Trails Advisory Body. Led a two-person team researching alternative governance models across Canada for recreational trails advisory bodies. Used a structured approach to identify key desired design elements, alternative governance structures, evaluate alternative models, and make recommendations for the BC trails context. (2013)

Marine Planning Partnership: Socio-economic data and editing. Supported MaPP planning team by gathering data on socio-economics including commercial fisheries and sport fishing along the BC coast and editing relevant sections of MaPP plans. (2013)

Environment Canada: Guidance on the valuation of ecosystem services for use in environmental assessment decision-making. Reviewed literature to identify existing gaps in the practice of environmental valuation in the environmental assessment context. Advised on the design of an expert workshop used to gather guidance on key issues in environmental valuation. Facilitated major portions of the workshop. Wrote guidance for Environment Canada to improve their in-house economic valuations of environmental impacts. (2012-2013)

Port Metro Vancouver: Facilitation of Technical Advisory Group in Support of Pre-EA Work for Marine Terminal Expansion at Roberts Bank. Co-designed a multi-meeting, multi-month process to engage technical experts to gather advice for Port Metro Vancouver (PMV) and their consultants to improve their baseline studies and environmental assessment methods for the proposed Terminal 2 project. Facilitated meetings over Fall 2012 and Winter/Spring 2013 in support of process, and worked with PMV consultants to refine issues and enhance their ability to engage with the technical experts. Lead facilitator for the Coastal Geomorphology technical advisory group (one of four such groups convened as part of this contract). (2012-2013)

Gitga'at First Nation: Assessment of the potential economic impacts of the Enbridge Northern Gateway Project. Assessed the potential economic impacts of the Enbridge Northern Gateway pipeline and tanker project on the Gitga'at Nation and examined broader issues such as how to incorporate risk information into decision-making. Critiqued the proponent's application, established baseline data, conducted original impact assessment work, and wrote evidence that was submitted to the Joint Review Panel examining the project. Testified to the Panel in April 2013. (2011-2013)

BC Environmental Assessment Office: Refinement of Impact Assessment Methodology. Co-wrote discussion paper for the BC EAO making suggestions with respect to how the BC government might modify the existing environmental assessment process in order to strengthen the process, particularly with respect to cumulative effects assessment. This work involved identifying key outstanding issues, interviewing experts, and writing policy guidance. (2012)

Cumulative Environmental Management Association: Support for a structured decision-making process to identify solutions to linear footprint management issues in the oil sands. Developed objectives and measurement criteria, and led workshop discussion on these topics, for work on the linear footprint management plan for the Stony Mountain 800 Area south of Fort McMurray. The objective of this project was to identify recommendations for government to address multiple uses of the area, including SAGD, forestry, trapping, and recreation. (2012)

City of Merritt: Water planning and conservation. Researched water conservation tools in support of recommendations to the City of Merritt for their new water plan, including interviewing of water experts in municipalities across BC and ranking of water conservation tools used across BC. Analyzed the City of Merritt's water use data. (2011)

Department of Fisheries and Oceans: Facilitation of SARA consultations for species recovery. Developed consultation strategies with DFO and facilitated two evening open-house meetings and five day workshops for stakeholder consultations required under the Species at Risk Act for the Salish Sucker, Nooksack Dace, Cultus Pygmy Sculpin, and Rocky Mountain Ridged Mussel. (2010-2011)

Haida First Nation: Evaluation of environmental and economic impacts of proposed NaiKun offshore wind project. Provided a third-party review of BC, federal, and consultant environmental assessments of the project in terms of gaps in data and logic, identified potential significant impacts, and advised on financial viability of the project. (2011)

Tides Foundation: Benefits of Marine Planning: An Assessment of Economic and Environmental Values. Reviewed the social and economic context for marine development on the BC coast and examined the benefits of marine planning with respect to environmental protection, economic development, and social capital. This research was also published in the journal Environments. (2009)

Department of Fisheries and Oceans: Review of potential impacts of renewable ocean energy development in BC. Reviewed the potential social and economic impacts of renewable ocean energy development in BC. Examined the potential for renewable ocean energy development (tidal, wave, and wind) on the BC coast, reviewed current levels of development, reviewed the socio-economic context of the BC coast, and explored how such development might affect employment, existing industries (e.g., air travel, aquaculture, forestry, and marine navigation), energy supply in rural areas, recreation, rural demographics, traditional activities, and other values. (2008)

Coastal First Nations: Review of environmental and socio-economic impacts of port development and shipping on BC North Coast. Reviewed the potential impacts of port expansion and shipping (including tankers) on the BC North Coast. Characterized the significance of potential impacts and reviewed potential mitigation measures, including Impact Benefit Agreements. (2008)

David Suzuki Foundation: Toward a National Sustainable Development Strategy in Canada. Researched and contributing writer of an examination of the legal and policy framework for sustainability planning across jurisdictions in Europe, Japan, the US, and Canada. Identified components across jurisdictions that facilitate a jurisdiction's ability to plan for and achieve greater sustainability. Report proposed a draft federal law which in 2008 was adopted by Parliament (Federal Sustainable Development Act). (2007)

Natural Resources Canada: National Circumstances Affecting Canada's Greenhouse Gas Emissions. Contributed to a quantitative study of factors shaping Canada's GHG emission patterns. Conducted analysis of emission patterns and contributing factors to emissions of Canada's residential housing, transportation, and wood processing sectors. This research was also published in the Energy Journal. (2005)

National Round Table on the Environment and the Economy: Canada's Energy and Greenhouse Gas Context. Contributed to a study on the linkages between Canada's energy sources and economy, international comparisons, and policy options for reducing GHG emissions. (2005)

Coastal First Nations: Review of offshore oil and gas development in BC. Literature review of the legal, environmental and socio-economic issues of offshore oil and gas development in BC and evaluation of the relevant planning process. Highlighted issues relevant to strategic and project-level decision-making. (2004)

Peer-Reviewed Publications

Joseph, C., T. Gunton, and M. Rutherford. 2017. A Method for Evaluating Environmental Assessment Systems. *Journal of Environmental Assessment and Policy* 19(3): 33 pp.

Joseph, C., T. Zeeg, D. Angus, A. Usborne, and E. Mutrie. 2017. Use of Significance Thresholds to Integrate Cumulative Effects into Project-level Socio-economic Impact Assessment in Canada. *Environmental Impact Assessment Review* (67): 1-9.

Joseph, C., T. Gunton, and M. Rutherford. 2015. Good practices for effective environmental assessment. *Impact Assessment and Project Appraisal* 33(4): 238-254.

Joseph, C., and A. Krishnaswamy. 2010. Factors of resiliency for forest communities in transition in British Columbia. *BC Journal of Ecosystems and Management* 10(3): 127-144.

Gunton, T. and C. Joseph. 2010. Economic and Environmental Values in Marine Planning: A Case Study of Canada's West Coast. *Environments* 37(3): 111-127.

Joseph, C., T.I. Gunton, and J.C. Day. 2008. Implementation of resource management plans: Identifying keys to success. *Journal of Environmental Management* 88: 594-606.

Bataille, C., N. Rivers, P. Mau, C. Joseph, and J. Tu. 2007. How malleable are the greenhouse gas emission intensities of high-intensity nations? A quantitative analysis. *Energy Journal* 28(1): 145-169.

Expert Evidence

Enbridge Line 3 Replacement project. Written and in-person testimony to the Minnesota Public Utilities Commission. 2017.

Ajax Copper/Gold Mine. Written and in-person testimony to Stk'emlupsemc te Secwepemc Nation Review Panel. 2016.

Kinder Morgan Expansion Project. Written testimony to the National Energy Board. 2015.

Enbridge Northern Gateway Pipeline. Written and in-person testimony to National Energy Board. 2013.

Peer Review of Research

Environmental Management

Journal of Environmental Assessment Policy and Management

Select Other Professional Publications

Joseph, C., and T.I. Gunton. 2010. Net economic and environmental benefits of an oil sands mine. Proceedings of the 29th USAEE/IAEE North American Conference in Calgary, Alberta, Canada, October 14-16, 2010.

Joseph, C. 2010. The Tar Sands of Alberta: Exploring the Gigaproject Concept. Proceedings of the Prairie Summit geography conference, June 1-5, 2010, Regina, SK.

Joseph, C., and T. I. Gunton. 2009. Benefits of Marine Planning: An Assessment of Economic and Environmental Values. Marine Planning Research Report No. 4. Prepared for Tides Canada Foundation. Burnaby, BC: School of Resource and Environmental Management, Simon Fraser University. 34 pp.

Nyboer, J., and C. Joseph. 2006. Development of Energy Intensity Indicators for Canadian Industry 1990-2004. Prepared for Canadian Industry Program for Energy Conservation and Natural Resources Canada. Canadian Industrial Energy End-use Data and Analysis Centre, Simon Fraser University. 32pp.

Nyboer, J., C. Joseph, and P. Mau. 2006. Development of Greenhouse Gas Intensity Indicators for Canadian Industry, 1990 to 2004. Prepared for Environment Canada and Natural Resources Canada. Canadian Industrial End-Use Energy Data and Analysis Centre, Simon Fraser University. 584pp.

Nyboer, J., C. Joseph, N. Rivers, and P.Mau. 2006. A Review of Energy Consumption and Related Data Canadian Aluminium Industries 1990-2003. Prepared for Aluminium Industry Association. Canadian Industrial Energy End-use Data and Analysis Centre, Simon Fraser University. 36pp.

Nyboer, J., C. Joseph, N. Rivers, and P.Mau. 2006. A Review of Energy Consumption and Related Data Canadian Mining and Metal Smelting and Refining Industries 1990-2003. Prepared for Mining Association of Canada. Canadian Industrial Energy End-use Data and Analysis Centre, Simon Fraser University. 159pp.

Presentations, Guest Lectures, and Workshops

Lead workshop for environmental professionals entitled "Environmental Assessment in Canada: Current Issues and Prospects for Improvement" for Faculty of Environment, Simon Fraser University, October 26, 2017. Vancouver, BC.

Lead workshop entitled "Valued Components Masterclass" at Canadian Institute's Cumulative Effects conference, June 21, 2017. Calgary, AB.

Presentation at Canadian Institute's Cumulative Effects conference entitled "Improving Cumulative Effects Assessment in Project-Level Assessment", June 20, 2017. Calgary, AB.

Presentation to SNC Lavalin staff entitled "Megaprojects: Navigating Failures, Bias, Symbolism, and Other Interesting Stuff", April 19, 2017. Vancouver, BC.

Presentations at IAIA'17 entitled "Benefits Assessment in Western Canada: Case studies and Lessons", April 6, 2017, and "Significance Thresholds to Integrate CEA in Project-level EA", April 7, 2016. Montreal, QC.

Presentation to the Federal EA Review Panel, December 11, 2016, Vancouver, BC.

Guest lecture to undergraduate economics class on economic impact assessment and the public interest, Simon Fraser University, March 13, 2014, Burnaby, BC.

Public presentation for Moving Planets on Enbridge Northern Gateway project, March 27, 2012, Squamish, BC.

Guest lecture to undergraduate environmental studies class on megaproject review and the Enbridge Northern Gateway pipeline project at Quest University, March 15, 2012, Squamish, BC

Guest lecture to masters environmental assessment class on tar sands project review, School of Resource and Environmental Management, Simon Fraser University, February 28, 2011, Burnaby, BC.

Presentation at Unwrap the Research Conference entitled "The Tar Sands of Alberta: Exploring the Gigaproject Concept", October 24, 2010, Fort McMurray, AB.

Presentation at 29th USAEE/IAEE North American Conference entitled "Net economic and environmental benefits of an oil sands mine", October 16, 2010, Calgary, AB.

Presentation at Prairie Summit 2010 geography conference entitled "The Tar Sands of Alberta: Exploring the Gigaproject Concept", June 4, 2010, Regina, SK.

Guest lecture to ecological economics class on cost-benefit analysis of tar sands development at Quest University, April 26, 2010, Squamish, BC

Presentation at community meeting on the economic risks of the Garibaldi at Squamish ski and residential project proposal, April 12, 2010, Squamish, BC.

Guest lecture on environmental assessment of large-scale projects to Geography 319 "Environmental Impact Assessment" at March 17, 2010, University of British Columbia, Vancouver, BC.

Public presentation hosted by Squamish Climate Action Network on Alberta Tar Sands, May 25, 2009, Squamish, BC.

Guest lecture entitled "Energy: A Love and Hate Relationship" to students at Capilano College, September, 2008, North Vancouver, BC.

Presentation to Butterfield & Robinson travel group on oil sands development, August 20, 2008, Calgary, AB.

Panel presenter at Whistler Energy Forum on energy and sustainability, June 8, 2008, Whistler, BC.

Presentation for REM seminar series entitled "Can Cost-Benefit Analysis be Improved with Stakeholder Involvement?", Simon Fraser University, November 1, 2007, Burnaby, BC.

Presentation at Canadian Pollution Prevention Roundtable entitled "Pricing Oil Sands Pollution? Balancing Expert and Stakeholder Input", June 14, 2007, Winnipeg, MB.

Presentation at ISSRM 2006 Conference entitled "Implementing Resource Plans: Lessons from BC", June 5, 2006, Vancouver, BC.

Presentation at PIBC Conference as part of session entitled "Planning Implementation: Lessons from the Field", April 19-22, 2005, Vancouver, BC.

Invited Speaker at "Dialogue Café" on climate change, February, 2005, Whistler, BC.

Co-presenter for REM Seminar series entitled "Offshore Oil and Gas in BC", Simon Fraser University, February 28, 2005, Burnaby, BC.

Presentation at BC Land Summit 2004 as part of session entitled "BC's Crown Land Planning Process - Does it Work?", May 14, 2004, Vancouver, BC.

Presentation at CONFOR 2004 conference entitled "An assessment of the British Columbia strategic land use plan implementation framework and an identification of best practices for plan implementation", Dalhousie University, February 6, 2004, Halifax, NS.

Presentation for REM Seminar Series entitled "An Evaluation of the BC Strategic Land Use Planning Implementation Framework: Best Practices, Current Practices.", Simon Fraser University, November 14, 2003, Burnaby, BC.

Presentation at Annual Meeting of the Western Division of the Canadian Association of Geographers entitled "The Impact of Rock Climbing on the Soils and Vegetation at the Base of Cliffs.", Kwantlen University College, March 12-14, 1998, Richmond, BC.

Co-presenter at Annual Meeting of the Western Division of the Canadian Association of Geographers entitled "The Geomorphology of Small Push Moraines at Hilda Glacier, Banff National Park, Alberta", Kwantlen University College, March 12-14, 1998, Richmond, BC.

Awards

Sustainable Prosperity research grant, 2011

Waterhouse Graduate Fellowship in Organizational Change and Innovation, 2009

Jake McDonald Memorial Scholarship, 2007

Canada Graduate Scholarship – Doctoral (SSHRC), 2006-2009

2nd Place, Photography, Vancouver International Mountain Film Festival, 2003

Treeplanter of the Year, Outland Reforestation, 1996

Student Leadership, Ontario Secondary School Teachers' Federation, 1993

TAB 2

Teck Frontier Mine:
Review of Economic Benefits and Cost-Benefit Analysis

August 22, 2018

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Executive Summary

Teck Resources Limited (Teck) proposes to build a new bitumen mine north of Fort McMurray called Frontier. Teck provides its estimate of economic benefits of the Project, as well as its predictions of the potential adverse effects of the Project, in its environmental assessment application and subsequent submissions. I was hired by the Athabasca-Chipewyan First Nation and the Oil Sands Environmental Coalition to review Teck's economic benefit information and conduct my own study of the economics of the Project.

Alberta and Canadian regulatory criteria emphasize that project proposals need to demonstrate that they are in the public interest. The information that Teck presents in its environmental assessment application does not accurately or comprehensively address this requirement.

Despite Teck's statements that their economic benefit information shows that the Project is a net benefit to society, Teck used a method of benefits assessment that is well-known in the economics profession to be deficient with respect to informing of net benefits. Teck used economic impact analysis based on input-output modeling to assess a subset of economic effects linked to its investment. This method ignores constraints in the economy, such as limits to investment capital and labour supply, and ignores a range of economic effects, such as incremental government burdens and the health costs of pollution. Teck provides information on the expected adverse effects of the Project in their environmental assessment application but does not synthesize this information with economic benefits information to inform of the Project's public interest value.

Using the standard method around the world for the evaluation of projects – cost-benefit analysis – I examined the Project in terms of the following benefits and costs:

- revenues from oil production;
- construction, operations, and reclamation costs;
- potential employment benefits;
- costs to government;
- impacts on other commercial activities;
- air pollution;
- greenhouse gas emissions;
- impacts on water resources; and
- impacts on ecosystem services.

I concluded that under base case assumptions the Project will be a net loss to society of $4.6 billion (net present value) and earn only an internal rate of return of 7.8%, suggesting that the Project is not in the public interest and not a good prospect for

investors (Table ES-1). I also found that little to no employment benefits should be expected from the project due to current and expected labour market conditions, and as such the Project has little if any public interest value from the perspective of jobs. Furthermore, while my cost-benefit analysis does incorporate a variety of environmental impacts, there are several adverse impacts not captured in my analysis results due to technical or philosophical reasons, suggesting that my results overestimate the Project's value to society.

Table ES-1. Key results of base case.

Indicator	Result
Net Present Value	$4.6 billion net loss
Private Internal Rate of Return	7.8%

There are numerous uncertainties in any modeling of a Project's future value, yet my sensitivity analysis suggests that the Project will be a net loss to society under a range of scenarios. I tested different oil price scenarios, environmental damage cost scenarios, Project cost scenarios, discounting scenarios, and the possibility of employment benefits. Only four scenarios yield a positive net benefit to society: ignoring greenhouse gas damages outside of Canada, the adoption of 3% and 8% uniform discount rates applied to all impacts, and adoption of the high oil prices assumed in the International Energy Agency's *New Policies* oil price forecast. There are reasons to doubt the appropriateness and/or realism of these scenarios given that: it is standard practice to consider the global damages of greenhouse gas emissions, not just those occurring within a jurisdiction; a 3% discount rate is not consistent with private investor expectations; an 8% discount rate is not appropriate for long-term environmental impacts; and the International Energy Agency oil price forecast is unlikely given global climate change concerns, likely future carbon policy, and technological change.

Similarly, in sensitivity analysis I found that the Project would be a relatively poor investment in all scenarios other than four of the 17 scenarios I tested: if 10% of labour would otherwise be unemployed, if the Project's operational costs end up being 25% less than what Teck predicted in 2015, if Teck's 2015 capital cost estimate ends up being correct, or if the International Energy Agency's *New Policies* oil price scenario is realized. The evidence suggests that none of these scenarios are likely, and so overall my findings support the conclusions of both the National Energy Board and International Energy Agency that new bitumen mines are unlikely to be built due to their poor financial outlook.

From a distributional standpoint, my results suggest that the Project is a gain only to the Alberta and federal governments. For investors my analysis finds that the Project will be a loss, and for citizens of Alberta, Canada, and the world my analysis finds also that the Project will be a loss due to adverse environmental impacts. While Aboriginal groups in the region may experience some employment benefits with the Project, few economic benefits should be expected by these groups without concrete commitments by Teck in the form of contractual obligations contained in an impact-benefit agreement. Regardless, I expect the Project to affect Aboriginal groups through its contribution to the cumulative effects of other development in the region, further compromising not just the landscape and water but the cultural and social activities that depend on them.

My findings challenge Teck's message of billions in benefits to governments, businesses, workers, and households. My overall finding is that the Project is likely to be a net loss to society and a poor private investment. Even if the Project was developed, workers have at least equal opportunities elsewhere. These conclusions, on top of the Project's substantial environmental impacts, call into serious question whether this Project is in the public interest.

Contents

Acronyms

AAAQOs	Alberta Ambient Air Quality Objectives
AER	Alberta Energy Regulator
CAPEX	capital costs
CBA	cost-benefit analysis
CDN	Canadian dollars
CEA Agency	Canadian Environmental Assessment Agency
CEAA 2012	*Canadian Environmental Assessment Act, 2012*
CERI	Canadian Energy Research Institute
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
EA	environmental assessment
EconIA	economic impact analysis
EPEA	Alberta *Environmental Protection and Enhancement Act*
GDP	gross domestic product
GHGs	greenhouse gas emissions
ha	hectare
kbpd	thousand barrels per day
IBA	impact and benefit agreement
IEA	International Energy Agency
NEB	National Energy Board
NO_x	nitrogen oxides
NPV	net present value
OPEX	operational costs
OSCA	*Oil Sands Conservation Act*
PM	particulate matter
PY	person-years
REDA	*Responsible Energy Development Act*
RMWB	Regional Municipality of Wood Buffalo

RPPs	refined petroleum products
RSCs	reduced sulphur compounds
SCC	social cost of carbon
SO_2	sulphur dioxide
TBCS	Treasury Board of Canada Secretariat
tCO_2e/yr	tonnes of carbon dioxide equivalent per year
USD	US dollars
VOCs	volatile organic compounds
WCS	Western Canadian Select
WTI	West Texas Intermediate

1. Qualifications

My qualifications are as follows:

- I have undergraduate, masters, and doctorate degrees in resource and environmental management;
- my doctorate was focused on the environmental assessment process, including an examination of appropriate methods of economic impact assessment for evaluating major energy projects, and a cost-benefit analysis of the Kearl bitumen mine;
- I have written and co-written peer reviewed articles on aspects of the environmental assessment process, economic valuation, and resource management policy;
- I have 15 years' experience consulting on the impacts of major projects, including oil and gas pipelines, bitumen extraction projects, LNG projects, mines, refineries, and port and shipping projects;
- I work as a private consultant, and from 2016 until earlier this year I was also the socio-economic impact assessment lead at SNC Lavalin;
- I have provided expert testimony to: the Minnesota Public Utilities Commission regarding the Enbridge Line 3 Replacement; to the National Energy Board regarding the proposed Enbridge Northern Gateway Project and the proposed Kinder Morgan Trans Mountain Expansion Project, and to the Stk'emlupsemc te Secwepemc First Nation's Review Panel for the proposed Ajax copper/gold mine;
- I have written guidance and advised the BC, Alberta, and federal governments on aspects of socio-economic impact assessment, economic valuation, and cumulative effects management; and
- I have instructed university-level and professional courses in economics, resource and environmental management, and environmental assessment.

A copy of my CV is presented in Appendix A.

2. Scope of Work

Teck Resources Limited (Teck) proposes to build a new bitumen mine north of Fort McMurray called Frontier (the Project). Teck provides its estimate of economic benefits of the Project, as well as its predictions of the potential adverse effects of the Project, in its 2011 and updated 2015 environmental assessment (EA) applications and subsequent submissions to the Alberta Energy Regulator (AER) and the Canadian Environmental Assessment Agency (CEA Agency).

I was hired by the Athabasca-Chipewyan First Nation and the Oil Sands Environmental Coalition to review Teck's economic benefits assessment and conduct my own study of the economics of the Project. Teck used the method of economic impact analysis (EconIA), which relies on input-output modeling, to assess the Project's economic benefits, and Teck used a variety of biophysical and human environment impact assessment methods to assess the Project's potential adverse effects. I relied on the method of cost-benefit analysis (CBA) for my study to examine both the Project's benefits and adverse effects.

CBA is the standard method in modern economics for assessing a project's value to society. CBA entails identifying a project's benefits and costs, and then summing these impacts to arrive at an estimate of a project's net benefits. While the method of CBA is not required under current Alberta and federal EA guidelines, CBA is a standard method for project evaluation in many other countries including Australia and New Zealand, EU countries, the US, and by international development banks, and is a standard method of economic analysis of proposed regulatory change in Canada, the US, and many other countries.

CBA was recently applied in a study of Alberta's oil industry by the Canadian Energy Research Institute (CERI) (Millington et al. 2014), an independent, charitable organization founded in 1975 to study and report on energy issues facing Canada and an organization that has been conducting studies of oil/tar sands issues for many years. As CERI noted (Millington et al. 2014, 2), CBA is superior to the EconIAs that are typically done as part of EAs in Alberta because while EconIA may:

> *highlight some of the economic effects of [projects] but [are] not reflective of the net social benefit of [projects] because [EconIA does] not account for opportunity costs of the resources used in the project, costs incurred by government, impacts on other players (if any) operating in the area and social environmental impacts. Such costs are an economic externality of [projects] that should be considered. [In contrast, CBA] provides a robust method for evaluating the costs and benefits (including both economic and non-economic impacts) of a project or policy change in today's dollars to society as a whole. [CBA] is not currently used by the regulatory agencies when making a decision to approve or reject a project, but [CBA] might serve as an additional tool for them to rank and assess options and decide whether to implement them.*

CERI raises the fundamental problems with the method of EconIA respecting the method's ability to assess the economic benefits of projects undergoing EA: constraints on development inputs such as labour are ignored, and only a subset of economic effects are examined leading to only a *gross* accounting of a project's economics (see s.5 below for more detailed discussion). CERI (Millington et al. 2014, 35) went on to conclude that

> *the CBA exercise was valuable in demonstrating the usefulness of the method as a framework for evaluating project costs and benefits. The CBA presents an alternative assessment of costs and benefits to an [EconIA conducted as part of an EA] which assumes that all impacts associated with the project are incremental and focuses on economic impacts instead of costs and benefits. The CBA also makes clear that there are other costs of the project not included in the [EconIA conducted as part of an EA].*

Given the Alberta and Canadian EA regulatory frameworks' concern with whether a project is in the public interest, including the *Canadian Environmental Assessment Act, 2012*'s concern with whether a project's significant adverse effects are "justified in the circumstances" (s.31(1)(a)), it is prudent to adopt methods of impact assessment that directly explore and inform such questions. CBA is the primary method in economics for assessing a project's net benefits, and thus I apply this method to the Frontier project.

In the next section of this report I provide a brief overview of the Frontier project, and in s.4 I review the regulatory context for the Frontier EA. In s.5 I provide a critique of Teck's assessment of the Project's economic benefits, and in s.6 I present my own analysis of the Project's economics. Section 7 of my report summarizes my main conclusions.

3. Overview of Project

As described in Teck's 2015 application update (2015 Application, Volume 1, s.1), the Frontier project is a proposed bitumen mine located north of Fort McMurray with a nominal capacity of 260 thousand barrels per day (kbpd). Two construction and operational phases are proposed: phase 1 construction would begin in 2019 and last through 2025 with phase 1 operations beginning in 2026, and phase 2 construction would begin in 2030 and last through 2036 with phase 2 operations beginning in 2037. Operations of the two-phased project would last until 2066 followed by final reclamation lasting until 2081. Teck first applied for approval for the Project to the AER and CEA Agency in a 2011 application but then updated the application in 2015 based on several design changes.

4. Regulatory Context

For EA purposes, the Project is being assessed under the following laws:

- the Alberta *Environmental Protection and Enhancement Act* (*EPEA*);
- the Alberta *Responsible Energy Development Act* (*REDA*);

- the Alberta *Oil Sands Conservation* Act (*OSCA*); and
- the *Canadian Environmental Assessment Act, 2012* (*CEAA 2012*).

Each of these laws require major project applicants to gather and present to regulators and the public a range of information on a project's potential negative effects and potential benefits, and each of these laws put forth various tests pertaining to whether a project proposal should be approved or not.

The *EPEA* requires proponents to gather a variety of information on a project's potential environmental (including non-biophysical) effects (AEP 2016). The *EPEA* does not set out a decision-making process, and thus there are no decision criteria listed in the act, but the act does indicate that it is intended to promote environmental protection and sustainable development (s.40).

The *REDA* identifies a set of decision criteria for major project proposals including:

- efficiency, safety, orderly, and environmentally responsible development of energy resources (s.2(1)(b));
- disposition and management of public lands, protection of the environment, and conservation and management of water, including the wise allocation and use of water (s.2(1)(b));
- factors prescribed by the law's regulations as well as the interests of landowners (s.15); and
- factors identified in regional plans made under the *Alberta Land Stewardship Act* (s.20).

The *REDA* does not include a specific public interest test unlike its predecessor, the *Energy Resources Conservation Act*, but the *Responsible Energy Development Act General Regulation* notes that the AER must consider:

- the social and economic effects of the energy resource activity,
- the effects of the energy resource activity on the environment, and
- the impacts on a landowner as a result of the use of the land on which the energy resource activity is or will be located (s.3).

The *OSCA* and associated AER directives require proponents to gather a range of information on a project's potential economic benefits and adverse environmental (including non-biophysical) effects. Decision criteria in the *OSCA* include:

- conservation and prevention of waste of bitumen resources, ensuring orderly, efficient and economical development in the public interest, controlling pollution and to ensure safe and efficient practices (s.3);
- orderly, efficient, and economic development of hydrocarbon resources (s.7(2)(b)); and
- the public interest (s.10(3)(a), s.11(3)(a).

The *OSCA* does not define the public interest, but decisions made under this law demonstrate how this concept is defined in practice. For example, in finding that the diversion of the Muskeg River for the Shell Jackpine Mine Expansion Project was in the public interest, the Joint Review Panel referred to industry predictions that the diversion would have low impact on water quality and flows, the low fisheries value and limited Aboriginal use of the affected area, the compensation proposed by the proponent, and the extent of sterilization of oil sands if the diversion does not occur as decision factors (Jackpine Mine Expansion Project Joint Review Panel 2013).

The *CEAA 2012* requires proponents to gather information on a project's purpose and why the project is needed, as well as information on adverse environmental effects. Decision criteria in the *CEAA 2012* are implied in the various purposes of the law listed in s.4 (which include environmental protection, sustainable development, maintenance of a healthy environment and healthy economy) and are identified in ss. 37, 52, and elsewhere regarding whether a project poses the likelihood of causing significant adverse effects and whether these significant adverse effects are justified in the circumstances. The *CEAA 2012* does not define the term 'justified in the circumstances'; I interpret this term to imply that final decision-makers conduct some sort of analysis of whether the positives of the project are likely to outweigh the project's negatives.

Altogether, the Alberta and Canadian regulatory framework requires evaluation of a range of economic, environmental, and other information to inform a decision on whether or not a project proposal is in the public interest and should be approved. While I leave it to statutory decision-makers to interpret this law and associated policy, I have written my report and conducted my analysis with this regulatory context in mind.

5. Critique of Teck Economic Benefits Assessment

5.1 Overview of Teck's Economic Benefits Assessment

In its 2015 application (Volume 1, p1-19), Teck came to the conclusion that

> *the Project is in the public interest and will yield substantial net benefits to residents of the Athabasca Oil Sands Region, to Alberta and to Canada.*

Teck appears to have based this conclusion on the following arguments (2015 Application, Volume 1, p1-19):

- Teck's experience and ranking as a sustainability leader;
- the Project's supposed ability to provide for North American energy security;
- the Project's use of a fly-in/fly-out program for workers to minimize stress on Fort McMurray;

- the opportunities provided by the Project for local Aboriginal employment;
- the Project's use of current technology;
- capital cost expenditures of over $20 billion, operating expenditures of over $77 billion over the life of the Project, an estimated 278,190 person-years (PY) of total employment across Canada, and tax and royalty payments of $66 billion (all in 2014CDN); and
- the Project's planned phase approach which is argued to limit labour and other types of cost inflation.[1,2]

Teck goes on to note on p1-22 (2015 Application, Volume 1) that the Project will provide:

- $20.6 billion in construction expenditures, an estimated 94,300 PY of direct, indirect, and induced employment across Canada related to construction, $18.3 billion in provincial gross domestic product (GDP), and $13.2 billion in household income (all in 2014CDN);
- annual operational expenditures of $2.1 billion once the Project is fully operational, 4,100 PY of direct, indirect, and induced employment annually in Alberta, annual GDP of $2.1 billion, and $2.2 billion in household income (all in 2014CDN);
- total payments of taxes and royalties to the Government of Alberta of $54 billion (2014CDN);
- total payments of taxes to the federal government of $11.8 billion; and
- total payments of $3.5 billion in municipal taxes to the Regional Municipality of Wood Buffalo (RMWB; all in 2014CDN).

With respect to these effects, but also in light of several adverse effects noted by Teck in their socio-economic impact assessment, Teck later argues that

> *from a socio-economic perspective, the updated Project is expected to be a net contributor to the study area, Alberta and Canada (2015 Application, Volume 1, p16-2)*

and then on p16-38:

> *[t]he analyses presented in the updated [socio-economic impact assessment] support the conclusion that the Project will be a net benefit to the RMWB, Alberta and Canada.*

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[1] The qualifier "2014CDN" signifies Canadian dollars in the year 2014. Given differences in purchasing power between country currencies, and how inflation over time changes purchasing power, I specify such details throughout my report.

[2] Employment impact information expressed in terms of person-years (PY) can easily be misinterpreted. One PY is one person working for a year at a job. However, if that single person works for ten years then there is ten PY of employment. Alternatively, ten PY could mean ten people working for one year.

Most recently, in its May 2017 response to information requests (Information Request Package 5, p5-9), Teck presents some updated economic benefit information. Under its "reference oil price" scenario, Teck estimates that the Project will have the following economic impacts from phase 1:

- Alberta royalty payments of $46.8 billion and Alberta income taxes of $8 billion;
- federal tax revenues of $12 billion;
- municipal property taxes of $3.6 billion;
- operations expenditures in Alberta of $18.3 billion;
- Alberta and federal carbon tax payments of $635 million;
- construction GDP of $12.3 billion, and annual average operations GDP of $1.5 billion; and
- household income during construction of $7.5 billion and during operations of an annual average of $790 million (all CDN dollars).[3]

5.2 Teck's Assessment Fails to Inform of Net Benefits

Typically in EA, the objective is to forecast the *incremental* effects of a proposed project. Impact assessors make predictions about the *residual* effects of projects on the environment, communities, and other things that people value after mitigation measures are taken into account. As such, what is of interest is the *net* effects of a project beyond what would've happened otherwise, not the *gross* effects where mitigation measures or other offsetting or altering factors are not considered.

However, the method of EconIA used by Teck in its economic benefits assessment is not able to estimate net benefits except under very limited circumstances. The reason that EconIA cannot inform of net benefits is because EconIA is not designed to do so but instead is a method for understanding the gross economic impacts linked to a 'shock' to an economy such as a major investment.

EconIA begins with estimation of a project's expected capital costs, operating costs, and labour needs. These estimates are then used to estimate the project's direct, indirect, and induced economic effects on indicators such as GDP, employment, labour income, and government revenue.[4] Indirect and induced effects associated with a project's direct effects are estimated using multipliers derived from input-output modelling or other techniques. GDP can be estimated in several ways but in the project context can be derived from the project's revenue and the proponent's spending plans, and multipliers are used to estimate associated indirect and induced GDP. Direct employment is based

[3] Teck does not indicate the dollar years of these estimates.

[4] Direct effects are the initial inputs, e.g., the cost of project capital, operating costs, and the labour directly employed on the project. Indirect effects are the project's purchases of supplies and services. Induced effects are the purchases of project employees.

on the proponent's expected direct requirements based on engineering estimates, and multipliers are used to derive associated indirect and induced employment. Direct labour income is the proponent's anticipated compensation multiplied by direct employment estimates, and associated indirect and induced labour income is derived from indirect and induced labour estimates and wage rates in affected industries. Government revenue is derived from estimates of the project's anticipated costs and production, oil price, and royalty and tax rates.

This information provided by an EconIA is not informative of net effects for two main reasons.

First, EconIA ignores constraints in the economy, a well-known and well-documented limitation of the method (Davis 1990; Denniss 2012; Grady and Muller 1988; Kinnaman 2011; McDonald 1990; Shaffer 2010; Tombe 2016). In a well-functioning economy like Canada's, most labour and investment capital have alternative opportunities. Under this condition, the labour and capital used by a project such as Frontier is not free but a real cost to the economy since if used on the Frontier project this labour and investment capital cannot be employed or used elsewhere. In simpler terms, an employee working on Frontier can't work elsewhere at the same time, and investment monies put towards Frontier can't be invested elsewhere. This means that there is an *opportunity cost* to employing labour and investment capital on the Frontier project: if used in one place, the opportunity presented by the alternative use is foregone. Yet in EconIA the limits of supply of labour and investment capital are ignored and EconIA treats these costs to a project proponent as benefits because EconIA is not designed to look at net effects but instead to identify the magnitude of economic impacts linked to an investment. While project costs (such as capital and operating costs, and wages paid to employees) may be framed as benefits generated by a project, these impacts and linkages are not incremental benefits to the economy but money spent in the hopes of earning a return on investment. An illogical consequence of EconIA's ignoring of constraints is that a project is more 'beneficial' if a project costs more per unit of output compared to a project that costs less – higher costs are interpreted in EconIA as inherently beneficial. In my CBA I value Project inputs in terms of their opportunity costs, which is the standard practice in CBA.

The explanation for why EconIA ignores constraints in the economy (and thus treats project costs as economic benefits) is that EconIA is designed to trace the linkages between a change in one part of a geographically-bounded economy with other parts of that same economy. For example, if a new pulp mill is built in a region, then that mill will need inputs (such as forest fibre but also machinery, electricity, and workers), some of which may be obtained by suppliers in the region. EconIA can be used to understand the ripple effects of that investment across the region's economy, and the method can be used to examine the regional incremental economic impacts of development because investment in the region may not be assured and therefore there may not be any opportunity costs to that money within the region. However, from a larger geographic scale, this assumption of no opportunity costs is usually invalid. The issue is one of how the method of EconIA is applied and how results are interpreted.

The second main reason that EconIA does not inform of net effects is that EconIA considers only a limited subset of impacts and thus provides only a partial picture of a project's economic effects. EconIA concerns itself with the financial transactions associated with capital and operational spending, spending on labour, and revenue owing to government, but EconIA ignores other economic transactions such as environmental costs and costs to government associated with a project. For example, the public health care costs to treat asthma caused by air pollution are ignored, and government expenditures that may be incurred with a project, such as investment in new roads or road maintenance that is required to support the project, is ignored. Consequently, EconIA is incapable of examining the net benefits of a project, and these examples further highlight how EconIA was never designed to assess net benefits. I cover several notable costs of the Frontier project in ss. 6.6 through 6.12 below that need to be accounted for in any assessment of the project's net benefits, and while Teck examined many of these topics in other parts of their EA Teck did not look at these impacts from an economic perspective to the detriment of their assessment of the Project's economic benefits.

Another reason why EconIA does not inform of net benefits is the tendency for EconIA outputs to be presented alongside one another as if they were separate benefit streams that can be summed to indicate a project's total benefits. This is not the case and a problem (conscious, or unconscious) of presentation. For example, presentation of capital and operating expenditure 'benefits', GDP 'benefits', and labour income 'benefits' is duplicative – workers only get paid once, despite their wages being a component of capital and operating costs, an input to GDP, and labour income. Outputs from EconIA studies therefore require careful interpretation.

A common problem with EconIA as it is typically practiced and reported is a lack of concern for uncertainty, in contrast to standard good practice in forecasting and EA. Teck's EconIA – particularly expenditure 'benefits', GDP, and royalty and tax revenue estimates – rests upon two critical but uncertain inputs: project costs and oil price. Teck acknowledges how cost (and workforce) estimates that are used in its economic benefits assessment are uncertain (2015 Application, Volume 1, p16-15) but only explores the effect of uncertainty on its results in terms of alternative oil price scenarios in analysis from May 2017 (Information Request Package 5, p5-5+). An analysis of the effect of alternative Project costs has not been done by Teck, and an analysis of alternative prices should've been presented in the original application. I discuss uncertainties of Project cost and discuss the history of cost overruns in bitumen and other projects in s.6.4, and I show in ss. 6.14.2 and 6.14.3 how the net benefits of the Project and the scale and distribution of benefits are highly contingent upon Project costs and oil price.

Another problem with Teck's economic benefit assessment is that they didn't provide information on the multipliers that they used in their EconIA. Multipliers are central to calculations of indirect and induced effects, and thus for transparency and validation purposes it is essential to publish the multipliers used, the methodology used to estimate the multipliers, and the limitations of multipliers.

Teck claims on p5-10 in its Information Request Package 5 that the Project "will be economically robust, financially viable". However, no information is provided on the Project's financial viability. Teck provides updated information in this information request package on royalties, tax revenues, expenditures, GDP, and household income, but Teck does not provide any information on the Project's private net present value which would substantiate its statement on the financial viability of the Project.[5]

In summary, Teck's economic benefits assessment provides insufficient information to decision-makers and stakeholders. Teck states in its EA application and later filings that it provides information on the Project's net benefits, and that the net benefits of the Project are positive, yet Teck's methodology is incapable of informing of net benefits. Teck uses the method of EconIA, which ignores constraints in the economy and only considers a limited subset of economic effects, among other limitations. As a result, Teck's assessment informs only of gross economic impacts, not net benefits. Furthermore, Teck has still not considered the effect of uncertainty in one key parameter – Project cost – in its assessment of benefits, and as such Teck's results are not robust.

6. Cost-benefit Analysis of Proposed Teck Frontier Mine

6.1 Overview of Method of Cost-benefit Analysis

CBA is the standard method in the economics profession for evaluating the net benefits of major projects to society. The method first came into practical use in the 1930s in the US to address water resource management issues, and by the 1950s much of the theoretical and practical foundation for CBA had been developed. Today, CBA figures prominently in major project evaluations, regulatory impact assessments, and other

[5] Net present value, or NPV, is the discounted sum of a project's benefits and costs over the life the project. Discounting is the process of converting benefits and costs that occur at different points in time into a common temporal unit. See s.6.13 for further discussion on discounting.

policy contexts in many countries including Canada, Australia, New Zealand, European Union countries, the United States, Chile, and by international development banks such as the World Bank. CBA is not currently mandated for EA in Canada or Alberta, though the method has been used in EAs in Canada on various occasions (McLeod-Kilmurray and Smith 2010).[6]

CBA revolves around the notion that the welfare of society is equal to the sum of the welfare of all individuals. The objective of CBA is to identify how a project may change individuals' welfare and to aggregate all of these effects to indicate whether a project creates a net gain or loss in social welfare. The reliance in CBA on individuals' valuations of impacts is based on a fundamental assumption of the method and of modern economics that human preferences (as expressed in the marketplace or otherwise) should count in decision-making (Pearce 1998). In doing so, CBA evaluates the net impacts accruing to society as a whole instead of gross benefits or gross costs that might occur to any one individual party.

The basic steps in CBA in are: (1) specify alternative scenarios, (2) determine standing, (3) catalogue potential impacts of the project with positive impacts being benefits and negative impacts being costs, (4) predict impacts quantitatively over the life of the project, (5) tabulate impacts in monetary terms including converting any impacts not normally measured in monetary terms into such terms as appropriate and feasible, (6) discount these monetized impacts, (7) compute net present values (NPV) and internal rates of return (IRR) of alternative scenarios, (8) perform sensitivity analyses to test the effect of uncertainty on results, and (9) interpret results (Boardman et al. 2011). Benefits and costs that result from a Project (i.e., outcomes) are measured in terms of peoples' willingness to pay for positive impacts or what people require as compensation for negative impacts, and Project inputs are measured in terms their opportunity costs.

The key outputs of a modern, good practice CBA are estimates of a project's NPV, the project's IRR for the private developer, the distribution of predicted benefits and costs, and results from sensitivity analysis to address uncertainty. A positive NPV suggests – from the perspective of modern economics – that a project would be a net gain for society, while a negative NPV suggests that a project would be a net loss. The IRR is indicative of the private profitability of a project; if the IRR is below the private sector's earning expectations then the analysis suggests that the investment should not be made. The distribution of benefits and costs across groups in society is an important aspect of interpreting CBA results (TBCS 2007; US EPA 2010 (updated 2014)), as while a

[6] Dated guidance by the former Alberta energy regulator (ERCB 1991) states that CBA is required as part of energy project applications, but I'm not aware of whether this guidance has any practical relevance to the current EA process in Alberta.

project may be a net social benefit there may be certain groups who lose substantially.[7] Sensitivity analyses are important because they inform of the robustness of a project's social value: if a project is only a net social benefit under limited circumstances (such as only particularly high oil price forecasts) then the project may be considered too risky to proceed.

Like any method of impact assessment, CBA has a variety of limitations. Some of the most common critiques of CBA include: difficulties valuing impacts on things not normally traded in the marketplace (e.g., impacts on the environment), a focus on an individualistic consumer perspective as opposed to peoples' broader societal preferences, CBA's 'one dollar-one vote' logic which means that the distribution (and equitability) of money across individuals in society is ignored, controversy over key parameters such as the appropriate discount rate, and lack of understanding and mistrust (e.g., Anonymous 1992; Boardman et al. 2011; Boardman et al. 2010; Brown 1984; Jacobs 1997; Knetsch 2007; Sagoff 1988; Sen 2000; Vatn and Bromley 1994).

Despite these limitations, CBA remains the prime method from the discipline of economics for assessing the net benefits of major projects to society, also referred to as a project's social value. As CERI (Millington et al. 2014, 35) noted upon completing its CBA of a proposed greenfield refinery in Alberta:

> *the CBA exercise was valuable in demonstrating the usefulness of the method as a framework for evaluating project costs and benefits. The CBA presents an alternative assessment of costs and benefits to an [EconIA conducted as part of an EA] which assumes that all impacts associated with the project are incremental and focuses on economic impacts instead of costs and benefits. The CBA also makes clear that there are other costs of the project not included in the [EconIA conducted as part of an EA].*

To provide perspective on the actual net benefits of the proposed Frontier mine I applied the method of CBA by building a spreadsheet-based, quantitative model in Microsoft Excel. All monetary figures described in my CBA are expressed in 2017 Canadian dollars ($2017CDN) unless otherwise specified. Conversions of Canadian dollar amounts from other years are made using the Canadian Consumer Price Index, and conversions of US dollars are made using a US inflation calculator. While Teck used a 0.9 CDN:USD exchange rate (2015 Application, Volume 1, p16-14), I relied on the National Energy Board's (NEB) 0.837 CDN:USD exchange rate (NEB 2017) which is much closer to actual rates in the last few years.

[7] Note that taxes and royalties paid to governments are transfers from one party to another and have no effect on the NPV of a project to society, but these transfers do affect the IRR of a project because IRR is calculated from a private investor perspective.

For step one in my CBA of the Project, the scenarios for comparison are two futures: one with and one without the Project. As such, the incremental change associated with the Project and valued in the CBA are those impacts of the Project that wouldn't otherwise be reasonably expected to occur in the absence of the Project.

The second step in CBA is to determine standing, i.e., to who do benefits and costs of the Project count? My CBA is conducted from the perspective of Canada.

Steps three through nine, including an examination of the distribution of predicted benefits and costs, are presented below in ss. 6.2 to 6.14. Many impacts are assessed quantitatively and in monetary terms, but in some cases impacts are not amenable to quantification and monetization and thus are only assessed qualitatively.

For each part of my CBA when there is uncertainty as to appropriate model inputs I either make a judgment on the 'most likely' model input (and provide a rationale), or where I have little basis for which input may be most likely I test alternative inputs. In the results section (s.6.14) I present the range of results that stem from the different inputs.

6.2 Development Schedule

According to Teck (2015 Application, Volume 1, p1-8), construction will entail two phases: phase 1 will begin in 2019 and last through 2025, and phase 2 will begin in 2030 and last through 2036. Operations are expected to commence in 2026 and last through 2066 (for a 41 year life). The Project is expected to have a nominal capacity of 260 kbpd (2015 Application, Volume 1, p1-2). Teck expects an initial 85 kbpd of production of bitumen in 2026, 170 kbpd of bitumen by 2027 as phase 1 operations ramp up, and then 260 kbpd of bitumen by 2037 when phase 2 operations commences (2015 Application, Volume 1, p1-8). Reclamation of the Project is currently expected to occur from 2066 through 2081. I rely on this schedule for my CBA.

Teck doesn't note a capacity utilization factor in their EA application, but it is common for projects to produce at a lower rate than their nominal design capacity. The relatively newly-built Kearl mine, for example, has produced at an average of 73% of design capacity since project start, and while Kearl achieved its highest capacity utilization in 2017 (89%) its production to date in 2018 is only 86% (Oil Sands Magazine 2018). The National Energy Board (NEB) notes that 85% is a typical capacity utilization factor for oil sands projects (NEB 2018, 5), the AER (2018) reports 90%, and CERI in its most recent oil sands supply cost study assumes an 89% factor (D. Millington, CERI lead author, pers. comm., February 26, 2018). In my analysis I use the average (88%) of each of the NEB, AER, and CERI capacity factors.

In summary, I used Teck's stated construction, operations, and reclamation schedule as a foundation for my CBA model. I used Teck's stated nominal production but use a capacity utilization factor consistent with established energy authorities to arrive at actual production.

6.3 Revenue from Oil Production

The main benefit of the Project is revenue earned from the production of oil, eventually paid out to employees and suppliers in the form of wages and purchases, government in the form of royalties and taxes, and to shareholders. Revenue from oil production is calculated by multiplying annual production of oil (s.6.2) by price, and thus estimating the Project's revenue requires the identification of future oil prices. Predicting future oil prices is notoriously difficult, and so this step is one of identifying a range of reasonable oil price forecasts.

In valuing the Project's output of partially deasphalted bitumen, Teck assumed an "average long-term oil price of $95 (USD, year unspecified) per barrel of West Texas Intermediate" (WTI) (2015 Application, Volume 1, p16-14). In its May 2017 submission (Information Request Package 5, p5-4) Teck later explained that it tested three price scenarios based on International Energy Agency's 2016 World Energy Outlook (IEA 2016):

- a *base case* scenario averaging $95/bbl ($2016USD WTI) over the 2015 to 2040 period based on the IEA's 2016 *New Policies* scenario, which assumes implementation of existing and new carbon policies announced as of mid-2016;
- a *low price* scenario averaging $76.51/bbl ($2016USD WTI) over the 2015 to 2040 period, which Teck says is based on the IEA's 2016 *450* scenario and which the IEA states is consistent with meeting the Paris Accord climate change commitments; and
- a *high price* scenario averaging $115/bbl over the 2015 to 2040 period ($2016USD WTI; Teck does not identify the source for its high price forecast).

Since Teck generated its price forecasts for its May 2017 submission, oil market forecasts have become more pessimistic, rendering Teck's price forecasts outdated.

The most recent International Energy Agency (2017) published in November 2017 forecast presents three price scenarios for "IEA crude"[8]:

- *Current Policies*, which assumes that none of the new policies that have been announced by governments are implemented. This scenario predicts that oil

[8] The IEA forecasts are for "IEA crude" oil which I assume is roughly equivalent to West Texas Intermediate priced at Cushing, Oklahoma.

prices will rise to $97/bbl (2016USD IEA crude) in 2025 to $136 (2016USD IEA crude) in 2040.

- *New Policies*, which is based on existing and new policies announced as of mid-2017. This scenario predicts that oil prices will be $83/bbl (2016USD IEA crude) in 2025 but rise to $111 (2016USD IEA crude) in 2040, which is about $18/bbl (2016USD IEA crude) lower than the IEA's 2016 *New Policies* scenario (IEA 2017, 52). Under the 2017 *New Policies* scenario the IEA forecasts some expansion in bitumen output from Canada up to 2025 from completion of projects currently under construction but very little expansion after 2025 due to the high cost of production relative to alternative sources of supply. Further, the IEA concludes that the limited bitumen expansion that does occur will consist of lower cost *in situ* projects, not higher cost mining projects such as Frontier.
- *Sustainable Development*, which is based on meeting the Paris Accord climate commitments and UN millennium goals. Prices in this scenario are forecast to be $72 (2016USD IEA crude) in 2025 and then gradually declining to $64 (2016USD IEA crude) in 2040, leading to a decline in world oil production.

The NEB's forecasts are also more pessimistic than what Teck forecasts. In October 2016, the NEB released an updated 2016 forecast (NEB 2016). The updated forecast provided three scenarios:

- a *reference* case, in which oil prices would gradually rise to the $80/bbl (2015USD Brent, or $81 2016USD Brent) range over the 2020 to 2030 period;
- a *high price* case, which assumed oil prices would rise above $100/bbl (2015USD Brent, or $101 2016USD Brent); and
- a *low price* case, which anticipated that oil prices would remain below $50/bbl (2015USD Brent, or $51 2016USD Brent), and that Canadian production would peak in the mid-2020s and gradually decline thereafter.[9]

The NEB noted that its updated forecast did not incorporate the impacts of Canada's future climate change policies, which would further reduce fossil fuel production.

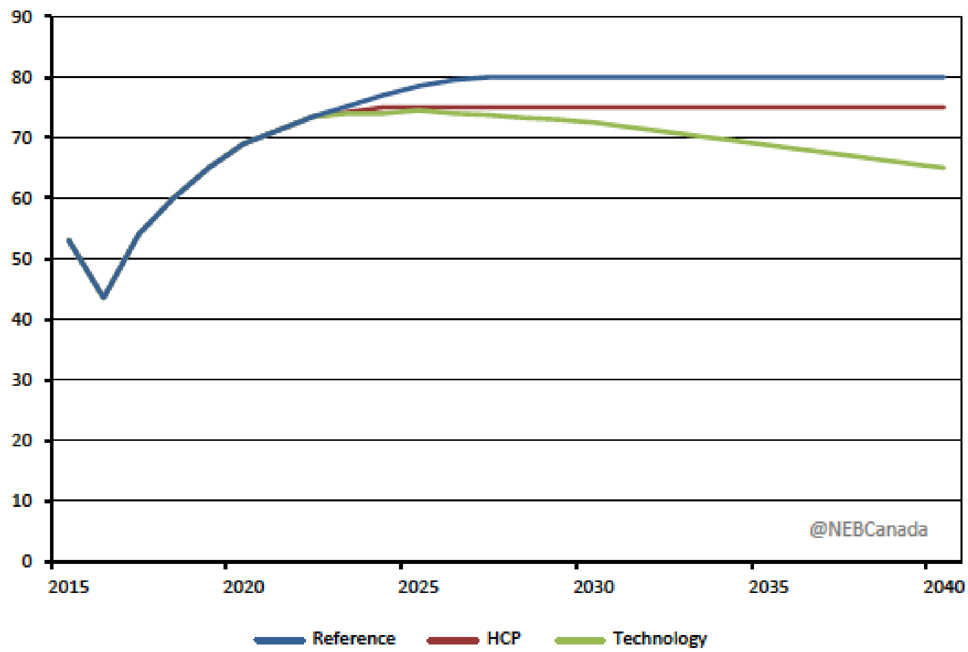
The most recent suite of NEB forecasts (NEB 2017) are also more pessimistic than Teck's forecasts. The NEB presents three price forecasts (Figure 1):

- a *Reference Case*, which forecasts oil prices gradually rising to $78/bbl (2016USD Brent) by 2027 and remaining at this level throughout the forecast period to 2040;
- a *High Carbon Price* scenario, in which oil prices peak by 2025 at $75/bbl (2016USD Brent); and

[9] Brent and WTI prices are roughly comparable, and under my assumption that "IEA crude" is comparable, all prices in this section of my report are comparable.

- a *Technology* scenario, which assumes faster penetration of new energy technologies such as electric cars and green energy, and anticipates oil prices gradually rising to $73/bbl (2016USD Brent) by 2025 and then gradually declining to $63/bbl (2016USD Brent) by 2040.

Figure 1. Most recent oil price forecasts from the National Energy Board ($2016USD Brent).



Source: NEB (2017, 20).

The NEB (2017, 35) concluded that under all three scenarios there will be no new mining bitumen projects built because prices will not be high enough to cover investment costs:

> *[a]fter mining projects currently under construction are completed and their production is brought up to capacity, no additional mining capacity is added over the projection period... crude oil prices do not reach high enough levels to encourage new investment.*

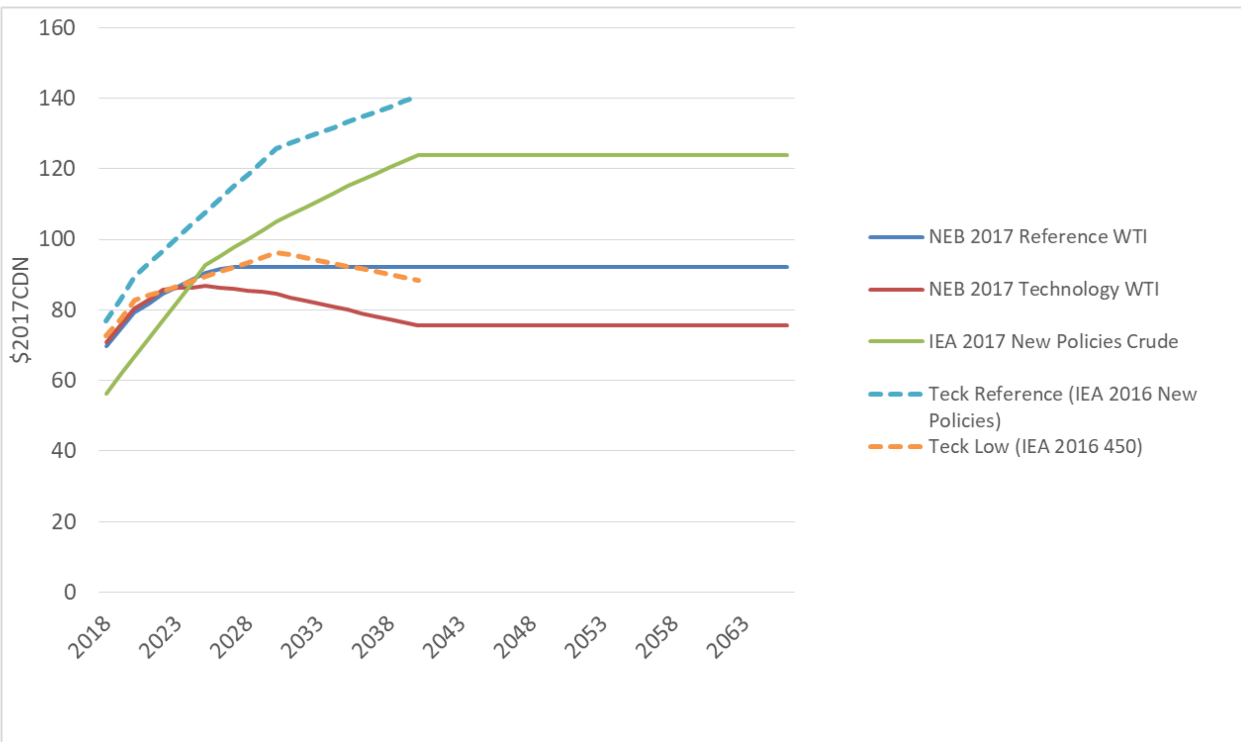
The NEB's most recent forecast and other recent studies highlight the challenges faced in the oil sands industry. Canadian bitumen is among the highest cost source of oil in world, and mining projects are the most expensive of bitumen projects (Jaccard et al. 2018; Rystad Energy 2016). CERI (Millington 2017) estimated new mines to be $16/bbl – 20% – higher than *in situ* projects. As such, even if oil markets rebound and prices rise higher than forecast, mining projects such as Teck's Frontier project will be less likely to proceed because there are lower cost and lower risk alternative investments available.

Based on my review of oil markets, I used three price scenarios for my analysis of the Frontier project (Figure 2):

- the NEB's 2017 *Reference Case* scenario as a base case scenario;
- the NEB's 2017 *Technology* Scenario, which assumes a more rapid adoption of new energy technologies and is similar to the IEA's *Sustainable Development* scenario, reflecting potentially lower future oil prices; and
- the IEA's 2017 *New Policies* scenario, which assumes that no new carbon policies are implemented to reduce GHG emissions other than those policies that had been announced as of mid-2017, reflecting potentially higher future oil prices.

As each of these oil price scenarios extended only to 2040 but the Project's operational life is planned to run to 2066, I extended the scenarios to 2066 by keeping the price constant after 2040.[10]

Figure 2. Three price scenarios used in my Frontier CBA (all in $2017CDN).[1,2,3,4]



Note: 1. The IEA only provides prices for intermittent years and so my IEA curve was developed through linear interpolation. 2. No line is shown for Teck's *high price* scenario as Teck only provides a long-term average price for their high price scenario of $115 (2015USD WTI) but no trend information over time. 3. The IEA 2017 *New Policies* scenario starts below $60 because its base year was 2016. 4. The two Teck forecasts extended only to 2040; I didn't extend the Teck forecasts as I didn't use them in my CBA.

[10] My assumption of constant prices past 2040 may under- or over-estimate future prices, depending on how oil markets transpire. This assumption seems the most reasonable course of action in the face of this uncertainty.

A second step in valuing the Frontier project's output is to translate the oil price scenarios identified in step one to what Teck would receive at the minehead. Doing so requires adjusting for the lower quality of bitumen relative to benchmark oil as well as accounting for transportation costs from the minehead to the distribution hub.

One method of bitumen valuation is that of CERI (Millington 2017) which entails valuing the Project's bitumen based on the price of Western Canadian Select (WCS), which is a benchmark Canadian heavy oil priced at Hardisty and incorporates quality and transportation cost differences relative to WTI. To implement this method I rely on the NEB's (Undated) latest forecast for WCS which anticipates a rise from $43/bbl in 2018 to $70/bbl by 2040. I take the NEB *Reference Case* scenario for WCS and make a further deduction of $1.37/bbl for transportation costs of diluent to the mine and transportation costs of the resulting diluted bitumen ("dilbit") from the mine to the Alberta distribution hub (Hardisty) based on information from CERI (D. Millington, CERI, pers. comm. March 11, 2018).[11]

An alternative method of valuing the Project's bitumen relies on a recent study by Wood Mackenzie for the Alberta Royalty Review (ARRAP 2016, pAdobe133) which estimated the price of bitumen at 60% of the WTI price (which I assume is at Cushing, Oklahoma, the main North American distribution hub for WTI). To implement this alternative method I applied this 60% differential to each of the WTI oil price scenarios to arrive at a value for the Frontier project's bitumen at the minehead. I have less confidence in this alternative method as the differential between bitumen and WTI does not always change proportional to changes in the WTI price.

Finally, note that while Teck's bitumen quality and transportation costs may vary somewhat from the quality and transportation cost parameters referenced above, these differences will be relatively small and are well within the range of the oil price forecasts that I used.

In summary, I identified three future oil price forecasts by reviewing a range of national and international forecasts, and then I applied two different methods of adjusting these price forecasts to arrive at a price for bitumen at the Frontier minehead. To get an estimate of Project revenues I then multiplied bitumen prices by the Project's anticipated production discussed in s.6.2.

6.4 Private Costs

The essence of a CBA of a project is to compare the benefits of development with its costs, and private costs to the developer are often the greatest component of total project costs. There are three main types of private costs of the Frontier project: capital

[11] I assume that the costs of diluent net out as Teck buys the diluent for the Project but can sell the diluent after use.

costs to build it (CAPEX), operational costs to run it while it is producing oil (OPEX), and reclamation costs.

Teck estimated the Project's CAPEX for both phases 1 and 2 to be $21.5 billion (2015 Application, Volume 1, p1-19), but I expect this to be an underestimate.[12] On a per barrel of capacity basis, Teck's CAPEX estimate ($82,562) compares closely with that of CERI ($82,041; Millington 2017) but is on the low end of the NEB's (2018) range of $80,000 to $95,000 per barrel of capacity, is low compared to the AER's (2018) range of $90,000 to $110,000 per barrel of capacity, and is low compared to three recently constructed bitumen mines. Kearl's cumulative CAPEX, for example, is just under $100,000 per barrel for its current 220 kbpd of capacity, and Kearl's per barrel of capacity is expected to amount to about $90,400 once the project achieves its planned 345 kbpd of capacity (Tait 2013). Healing (2017) reported that the CNRL Horizon project has a similar CAPEX per barrel capacity ratio as Kearl, and Fort Hills' CAPEX per barrel capacity is reported to be $88,000 to $90,000 (Anonymous 2018; Morgan 2018). Teck's estimate of $82,562 is from its 2015 EA application; the Project was early in the development process at that time, and cost estimates tend to rise as more detailed engineering is completed and construction begins (Olaniran et al. 2015). This is a pattern seen recently in Canada (e.g., Cryderman 2017; Deloitte 2017; Gunton 2017; Hendricks et al. 2017; Lewis and Fife 2018), around the world (Flyvbjerg et al. 2003; Olaniran et al. 2015), and in the history of the oil sands (AEDA 2004; Jergeas and Ruwanpura 2010), including for the most recently built oil sands mines. As such, it seems reasonable to assume that Teck's CAPEX estimate in its EA application will be an underestimate. Therefore, for my CBA I assumed a $90,000 CAPEX per barrel capacity ratio as a base case but I also tested Teck's 2015 estimate as a low case, and for a high cost case I used a 25% increase over the base case.

Given a lack of information in the EA application on annual CAPEX expenditures over the two construction phases, I also made the following two assumptions:

- CAPEX will be spent proportional to production capacity over the two phases, i.e., 65% of CAPEX is spent in phase 1 given that phase 1's capacity is 170,000 bpd, and 35% is spent in phase 2 given that the incremental capacity added in phase 2 is 90,000 bpd; and
- within phases, the timing of CAPEX will be spent consistent with the number of construction workers onsite (2015 Application, Volume 16 p16-9).

Teck estimates total OPEX (including sustaining capital but excluding energy) over the life of the Project of $80 billion and an annual average of $2.2 billion (2015 Application, Volume 1, p16-13). I used these amounts as the basis for OPEX in my CBA, as well as +/-

[12] All monetary values that I report are in 2017CDN unless indicated otherwise. See Teck references for monetary figures in dollar years used by Teck.

25% of these costs for sensitivity analysis, consistent with the alternative OPEX scenarios used in CERI's (Millington et al. 2014) refinery CBA. Given that Teck doesn't provide OPEX estimates by year, I assumed that OPEX will be spent proportional to production. Teck discusses how while the Project will produce more than enough electricity than it needs during phase 1 due to planned cogeneration, the Project will need to import electricity during phase 2. Lacking further information on electricity consumption I assumed that the Project's electricity needs are net zero. However, to account at least for Teck's natural gas consumption (as diesel and gasoline may yet be unaccounted for) I relied on CERI's (Millington 2017) assumption of 54,000 GJ/day of gas consumption for a new mine and the AER's (2018) forecast of future natural gas prices.

Teck did not provide a cost of reclamation and closure in their EA application, though it's possible that Teck included at least some of these costs (such as those associated with progressive reclamation) in their OPEX estimates. To estimate final reclamation and closure costs, given the lack of clarity in the Project application, I assumed a cost of 2% of CAPEX (which equals $429 million undiscounted), spread over the reclamation and closure years (2066 to 2081), consistent with CERI (Millington 2017). As Teck noted that reclamation costs will mostly be spent in the first 10 years of reclamation (2015 Application, Volume 1, p16-13), I assumed that 75% of reclamation costs will be spent over first 10 years of closure (2066 to 2075) and the remaining 25% will be spent over the remainder of the reclamation phase (2076 to 2081). Given uncertainty in the costs of future reclamation, and expert opinion (though dated) of oil sands reclamation costs ranging from $11,000 to $267,000 per hectare (Foote 2012), I also tested the effect of an average of these estimates (i.e., $139,000) applied to the Project area of 29,217 hectares (2015 Application, Volume 1, p13-2) and then spread out the resulting $4.1 billion over reclamation years, i.e., 75% over the first 10 years and 25% over the remainder.

In summary, I modeled the Project's construction, operations, and reclamation costs based on information Teck supplied in its application materials supplemented by information on other oil sands projects. Costs are allocated by level of activity, and the scenarios tested reflect cost uncertainty.

6.5 Employment

Employment associated with a major project is usually championed by developers as a key benefit of the project, but from the net benefits perspective of CBA employment is only a benefit if workers would otherwise be paid less or otherwise be unemployed. If one or both of these situations are the case, then a project's costs of labour is reduced accordingly to reflect the benefit earned by labour at the project compared to its alternative. In economic terms, this is a situation in which labour's opportunity cost is lower, as the alternative opportunity would pay less than the project. If neither of lower alternative earnings or unemployment can reasonably be expected for project workers, though, then wages and benefits paid to employees are simply costs of a project and tracked accordingly.

Teck anticipates requiring about 4,500 and 2,250 construction workers during phases 1 and 2, respectively, about 2,150 and 700 operations workers during phases 1 and 2, respectively, and about 200 reclamation workers (2015 Application, Volume 1, p12-8). Teck estimates that total wages paid over construction will be $6.6 billion (2015 Application, Volume 1, p16-11) and about $1 billion (2015 Application, Volume 1, p16-13).

However, Teck admitted in its EA application that:

> *[d]epending on the prevailing labour market conditions in the province at the time, this employment might not all be incremental to the Alberta economy (2015 Application, Volume 1, p16-10).*

On p16-11 Teck then noted that the labour market would likely be tight during the Frontier project's development (2015 Application, Volume 1), i.e., that existing supply of labour may not be able to meet demand. These are important acknowledgements that pertain to whether or not the Project will generate any net benefits for labour, and indeed recent labour market forecasts suggest that few net benefits should be expected.

BuildForce Canada (2018) forecasts a tight construction labour market due to numerous smaller-scale construction projects (including residential), the maintenance needs of existing and in-construction major projects, retirement in the construction labour workforce, and remaining bitumen development. In May of this year (2018), Alberta's general labour force unemployment rate was 6.5% (Alberta Undated-c), not much higher than the 6% natural unemployment rate (Jackson 2017; Millington et al. 2014; PetroLM/Enform 2018) and within the 5% to 7% range that others (BC Hydro 2013, s.17) place around the natural rate, suggesting few available workers for a new project.[13] This is consistent with PetroLM/Enform's fourth quarter 2017 labour market update (PetroLM/Enform 2017) which notes a tight oil and gas labour market unemployment rate of 4.7%.

All of this suggests that the Frontier project will not provide any incremental employment benefits, as Teck itself seems to have concluded. The labour market data and forecasts indicate and anticipate strong demand for labour, and therefore I assumed that labour will be able to find similar work at similar wages elsewhere if the Teck project doesn't go ahead. Under this conclusion of no employment benefit, the

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[13] The *natural rate of unemployment* reflects the fact that there are always people in between jobs or unwilling to work at a given point in time. Unemployment rates around 6% indicate a balanced labour market; rates higher than about 7% indicate excess of labour relative to job opportunities, and rates below about 5% indicate a shortage of labour.

Project's labour costs (which are components of the Project's CAPEX, OPEX, and reclamation costs) reflect the opportunity cost of labour and thus there is no reason to reduce CAPEX, OPEX, and reclamation costs.

However, it's possible that there is some incremental benefit to workers with this Project. Teck has indicated that it intends to facilitate local Aboriginal groups' interest in employment on the Project through such measures as providing flights for workers to and from Fort Chipewyan (2015 Application, Volume 1, pp 10-10 and 16-4), and unemployment rates in Aboriginal communities are relatively high. If any of these people – or other non-Aboriginals who would otherwise be under- or unemployed – work on the Frontier project then there is the potential that these workers would earn more than they otherwise would. Another scenario providing incremental employment benefits would be if specialized oil sands workers are able to earn a wage premium due to high demand for their skills. In either case, the cost of labour as components of Teck's CAPEX, OPEX, and reclamation costs should be lowered accordingly.

To test the scale of the effect of potential incremental employment benefits of the Project, in sensitivity analysis I assumed that 10% of the construction and operations employment goes to workers that are currently unemployed – 450 workers during phase 1 construction, 225 workers during phase 2 construction, 215 workers during phase 1 operations, and 70 workers during phase 2 operations.[14] To estimate the opportunity cost of labour, I further assumed that half of this labour is voluntarily unemployed, and the other half is involuntarily unemployed.[15] Under base case assumptions the resulting employment benefit is equivalent to a reduction on CAPEX and OPEX of 1.3% and 1.9%, respectively, which gives only a slight improvement on the Project's value to society (see s.6.14.2).

In summary, current and anticipated future labour market conditions strongly suggest that the Project would have no incremental benefit to labour. There is high demand for labour and little supply. However, I tested the possibility that 10% of the Project's labour would come from the unemployed and I found that this would have only a minor effect on model results.

[14] For the purposes of this test I ignored any effect on reclamation costs. Due to the relatively small workforce in final reclamation and the fact that this work would occur far into the future and thus be heavily affected by discounting, not to mention the uncertainty about labour conditions at that time, any estimated effect on the project's NPV from an adjustment to reclamation labour costs would be very small and unreliable.

[15] There is uncertainty about the opportunity cost of both voluntarily and involuntarily unemployed labour (Shaffer 2010), but according to Townley (1998) the value of the voluntarily unemployed is wages for the project net-of-tax, and for the involuntarily unemployed the value is in between an upper bound of wages net-of-tax plus benefits and a lower bound corresponding to the value that this labour puts on their leisure time (assumed to be 20%). For the voluntarily unemployed I thus summed the most recent federal and Alberta income tax rates (using a blended rate of 18% for federal tax; adding to 28%) and thus reduced 5% (i.e., half of the 10% assumed to otherwise be unemployed) of the wage bill portions of CAPEX and OPEX to 72% (i.e., wages net-of-tax) of what it would otherwise be. For the involuntarily unemployed I took the average of the upper (72%) and lower (20%) bounds (averaging to 46%) and reduced 5% of wage bills accordingly.

6.6 Incremental Government Costs

In CBA – as with any EA study of the effects of a project – it is important to consider all incremental costs that might be incurred in the course of development of a project. Teck states that the Project "will have a minimal direct effect on municipal costs" (2015 Application, Volume 1, p1-22), but even if such costs are small these costs should still be counted.

Government costs – whether municipal or senior government – related to providing infrastructure and services, some of which are used directly or indirectly by bitumen development projects (such as roads), are implicitly accounted for by the inclusion of sales, fuel, income and other taxes that appear in the expenditures captured in CAPEX, OPEX, and reclamation costs. These tax payments to government are designed to cover normal costs to government. However, major projects like bitumen mines can sometimes be associated with specific investments by government or other costs to government that wouldn't otherwise be made, and these costs should be counted.

In a past analysis of the Kearl bitumen mine (Joseph 2013) I determined that government was making several major investments that it wouldn't otherwise make had Kearl (and other major bitumen projects) not been planned or in development. These costs included investments in expansion of the Fort McMurray airport and in carbon capture and storage. In that study I also attributed a portion of government regulatory costs, including environmental monitoring, to the Kearl project. In total I estimated about $20 million (2010CDN) a year of incremental government costs associated with the Kearl project. McLeod-Killmurray and Smith (2010) also note how senior governments are often charged with the responsibility of monitoring and other activities when bitumen projects are approved, which creates incremental costs for government.

For the Frontier project I have not identified any substantial investments by government that wouldn't happen anyway, especially given a context of already substantial levels of bitumen development occurring in the region. However, there are incremental costs to each of the federal, Alberta, and RMWB governments associated with reviewing the Frontier application, and I would expect likewise some incremental costs to these governments to regulate the Project over its lifespan if the Project goes ahead. Given the relatively small size of these costs and the challenges of estimating them, I have not tried to estimate and include these costs to government for the present analysis.

6.7 Impacts on Other Commercial Activities

Development of the Frontier project has the potential to affect other commercial activities, and these effects are important to understanding the Project's net benefits. According to Teck, clearing and occupation of the Project site will affect forestry and trapping (2015 Application, Volume 1, p1-31). Such effects need to be accounted for, but in both cases I assumed that adverse effects on these other commercial users will be addressed through arrangements with Teck and the costs of which are already accounted. Forestry activity in the area by Al-Pac and Northland Forest Products will be interrupted, but Teck says that it will ensure that merchantable timber will be harvested during site preparation (2015 Application, Volume 1, pp 4-20, 13-40), and it is common for forest companies to be compensated for any long-term losses of timber value. Similarly, several trappers have traplines in the area (2015 Application, Volume 1, p1-31) but Teck indicates that compensation will be paid (2015 Application, Volume 1, p18-128). As such, I assume that these impacts on other commercial activities are accounted for in Teck's CAPEX and/or OPEX.

6.8 Air Pollution

Environmental costs can be a substantial cost of major development borne by society. Construction, operation, and (to a lesser extent) reclamation of the Project will lead to air pollution from equipment and from the mine face. Teck identifies numerous types of emissions including nitrogen oxides (NO_x), sulphur dioxide (SO_2), particulate matter (PM), volatile organic compounds (VOCs), greenhouse gas emissions (GHGs), reduced sulphur compounds (RSCs), and metals (2015 Application, Volume 1, p14-2). Aside from the impacts of GHG emissions which I address separately in s.6.9 below, the greatest impact of air pollution is that with respect to human health (Muller and Mendelsohn 2007; Spadaro and Rabl 2008). Teck expects that people in three communities would be exposed to the Project's air pollution: Fort Chipewyan, Fort McKay, and Fort McMurray (Table 1).

Table 1. Communities affected by Frontier air pollution according to Teck Frontier application.[1]

Community	NOx	SO_2	$PM_{2.5}$	VOCs	CO	RSCs	Metals
Fort Chipewyan	✓	✓	✓	✓	✓	✓	✓
Fort McKay	✓	✓	✓	✓	✓	✓	✓
Fort McMurray	✓	✓	✓	✓	✓	✓	✓

Source: 2015 Application, Volume 1, pp 18-22 to 18-23. Note: 1. Teck concludes that there will also be coarse particulate matter pollution (i.e., greater than 2.5 microns) but doesn't provide any forecast of this pollution, despite known health effects of this type of pollution (Health Canada 2016b; Muller and Mendelsohn 2007).

The Alberta government relies on the Alberta Ambient Air Quality Objectives (AAAQOs) (Alberta 2017a) to guide decision-making about acceptable levels of air pollution. The

AAAQOs are a function of scientific as well as social, economic, and technical factors (Alberta 2017a).

Teck predicts only one type of air pollutant from the Project to exceed an AAAQO in one community in the region: particulate matter less than 2.5 microns in size ($PM_{2.5}$) in Fort McMurray (2015 Application, Volume 1, p18-23). This suggests in the least that Teck's $PM_{2.5}$ pollution should be valued in my CBA. Further, as any amount of fine particulate matter pollution is harmful (Curtiss and Rabl 1996; Health Canada 2012; Samoli et al. 2005), all of Teck's emissions of $PM_{2.5}$ are damaging to those exposed to it, not just the portion of emissions beyond the AAAQO.

Similarly, I relied on recent reviews by Health Canada (2016a; 2016c) that concluded that health impacts of NO_x and SO_2 pollution occur at levels well below the levels of existing air quality objectives for these two pollutants, and that linear relationships exist between exposure to this pollution and health effects. As such, even low levels of Teck's NO_x and SO_2 emissions are damaging to those exposed to it.

Health Canada does not provide a health risk assessment of VOCs, but to be conservative in my CBA I also assume a linear dose-response function for this pollutant, and thus I consider all of Teck's emissions of VOCs as damaging to those exposed to it as opposed to just those emissions beyond some threshold concentration.

Due to a lack of damage cost factors for RSCs and metals (see below this section) I did not explore dose-response functions for these two pollutants.

The Project's air pollution will disperse throughout the region and reach the three affected communities that Teck identified. No study of the monetized damage costs of air pollution has been done for the Regional Municipality of Wood Buffalo, but this can be overcome by transferring damage cost values from other comparable studies to enable an approximation of Frontier's air pollution damages. I tested my model with air pollution damage cost factors from two studies.

For my base case I used the damage cost factors for NO_x, SO_2, $PM_{2.5}$, and VOCs for rural US locations presented in Muller and Mendelsohn (2007) (first row in Table 2), which have been used in other studies in Alberta such as CERI's refinery CBA (Millington et al. 2014).[16] In a sensitivity analysis I used damage cost factors from a more recent US study by Jaramillo and Muller (2016) examining air pollution from energy extraction (Table 2). Specifically, I used Jaramillo and Muller's damage cost factors for NO_x, SO_2, and $PM_{2.5}$ for the oil & gas extraction sector from 2011, which is the most recent year for which they provide damage cost factors. While I used the lower values from Muller and Mendelsohn (2007) in my base case I have no evidence to indicate if these values are

[16] Muller and Mendelsohn (2007) did not identify damage cost estimates for RSCs or metals.

more likely than the higher values from Jaramillo and Muller (2016). As such, my base case results may underestimate the actual costs of air pollutants from the Project and therefore overestimate overall net benefits of the Project.

Table 2. Air pollution damage cost estimates.

Study	Pollutant	Damage Cost ($2017CDN/t)
Muller and Mendelsohn (2007) – rural US	NO_x	$451
	SO_2	$1,353
	$PM_{2.5}$	$1,654
	VOCs	$451
Jaramillo and Muller (2016) – oil & gas extraction, 2011	NO_x	$6,136
	SO_2	$23,487
	$PM_{2.5}$	$53,608
	VOCs	not available[1]

Note: 1. As Jaramillo and Muller do not provide an estimate for VOCs I use the VOC estimate from Muller and Mendelsohn in the sensitivity analysis.

Table 3 presents estimates of Frontier's emissions by phase as well as estimates of damage costs. Teck provides air pollution estimates for a 277 kbpd project (2015 Application, Volume 1, pp 14-5 to 14-7), but to be consistent with the rest of my analysis (which assumes a 260 kbpd project) I scaled Teck's estimates down proportionally. Also, as Teck didn't provide emissions of pollutants by phase but instead only by source (such as from plant combustion stacks and mine fleet exhausts), I assumed that the only emission source during construction and reclamation are mine fleet exhausts. I used the damage cost values in Table 2 and the emission volumes presented in Table 3 to estimate air pollution damages by year in my CBA. Note that I wasn't able to monetize the Frontier project's emissions of PM_{10}, RSCs, or metals, despite this air pollution having some negative effect on human health and other receptors in the region, and so my NPV and IRR results overestimate the Project's value.

Table 3. Frontier mine emissions by phase.

Phase	Pollutant	Emissions	Estimated Costs - Muller and Mendelsohn (2007) Damage Cost Factors	Estimated Costs - Jaramillo and Muller (2016) Damage Cost Factors
construction[1,2]	NO_x	4,083t/yr	$1.8 million/yr	$96 million/yr
	SO_2	9t/yr	$13,000/yr	$220,000/yr
	$PM_{2.5}$	56t/yr	$98,000/yr	$3 million/yr
	VOCs	244t/yr	$110,000/yr	$110,000/yr
			total of $2.1 million/yr	*total of $99 million/yr*
operations[2]	NO_x	7,171t/yr	$2.6 million/yr	$133 million/yr
	SO_2	526t/yr	$563,000/yr	$9.8 million/yr
	$PM_{2.5}$	188t/yr	$260,000/yr	$8 million/yr
	VOCs	6,411t/yr	$2.3 million/yr	$2.3 million/yr
			total of $5.7 million/yr	*total of $153 million/yr*
reclamation and closure[1]	NO_x	4,083t/yr	$1.8 million/yr	$96 million/yr
	SO_2	9t/yr	$13,000/yr	$220,000/yr
	$PM_{2.5}$	56t/yr	$98,000/yr	$3 million/yr
	VOCs	244t/yr	$110,000/yr	$110,000/yr
			total of $2.1 million/yr	*total of $99 million/yr*

Sources: Teck Frontier 2015 application 2015 Application, Volume 1, pp 14-5 to 14-7. Notes: 1. Construction and reclamation emissions are derived from Teck's estimate of the amount of pollution from mine fleet exhausts. 2. Construction emissions are given for phase 1 construction, and operations emissions are the average emissions across operations years.

In summary, the Project's contribution to air pollution will impose damage costs (mostly health-related) on communities in the vicinity. I estimate these costs to amount to almost $6 million a year during the height of operations under one study's damage cost factors rising to as much as $153 million a year using an alternative set of factors. These conclusions are markedly different from Teck's conclusions (2015 Application, Volume 3, p4-3+) that changes to air quality will generally not be of any effect to people in the region.

6.9 Greenhouse Gas Emissions

GHG emissions pose costs to society that need to be accounted for in any assessment of a major project, and the Project will emit GHG emissions at the Project site in each phase. Teck notes that during construction over the years 2018 through 2036 Teck anticipates 19,800 tonnes of carbon dioxide equivalent per year (tCO_2e/yr) and an additional 86,900 tCO_2e/yr for site preparation over years 2019 to 2025 (2015 Application, Volume 1, p14-10). During operations, Teck anticipates an average of 4,082,000 tCO_2e/yr (2015 Application, Volume 1, p14-9), inclusive of indirect emissions associated with electricity demand. Teck doesn't provide GHG emission estimates for reclamation and closure, and so I assumed that the Project will emit the same amount of GHGs in reclamation years as Teck anticipates for construction years, i.e., 19,800 tCO_2e/yr.

These emissions – a maximum of 4.5 megatonnes per year which will occur during phase 2 operations – pose a damage cost to society in terms of climate change impacts on infrastructure, crops, human health, and many other things that people value. However, accounting for GHG damage costs requires that one take into account Alberta's carbon tax framework which requires large emitters to pay a tax for emissions above specified limits. The Alberta government states that it will use this tax revenue to address climate change (Alberta Undated-b), which in the CBA means a transfer from Teck to the Alberta government and eventually to citizens, all of which needs to be accounted for in the CBA.

Since January 1, 2018, facilities in Alberta emitting over 100,000 tCO_2e/yr by their second operational year must pay a carbon tax of $30/t in 2018 and rising 2% a year thereafter on their emission overages to the extent that their emissions intensity is greater than established benchmarks listed in the *Carbon Competitiveness Incentive Regulation* (Alberta Undated-a). The regulation specifies the GHG intensity limit for oil sands mines is 31.1 kilograms CO_2e per barrel in 2018 but declining after 2020; mines with higher intensities must pay the tax on their emission overages. Indirect emissions (e.g., from electricity imports) count towards the mine's emissions (Alberta 2017b). Teck doesn't provide an estimate of the Project's carbon tax liability in their application but did provide estimates in its 2017 Information Request Package 5 under alternative oil price forecasts: under their reference price forecast Teck estimates total carbon tax revenue of $635 million. However, Teck's estimate of carbon tax liability is based on the older, less stringent Alberta carbon tax framework, ignores indirect emissions, and may be based on different production numbers. As such, I estimated the Project's carbon tax liability myself as part of my CBA by calculating the Project's emission intensity from Teck's emission data (about 54 kg CO_2e /bbl during full operations), comparing this intensity to the regulated intensity limit, and multiplying the associated overage emissions (about 2.4 megatonnes CO_2e per year in the first year of phase 2 operations and rising from there) by the Alberta carbon tax rate.

I estimated an Alberta carbon tax liability of $50 million in the Project's second year of operations (2027), rising to $106 million by 2037 when full production is achieved, and continuing to rise on a year-over-year basis given the emissions limit decreases over time and the tax rate rises over time. I estimate total payments of $5.6 billion (undiscounted). Teck might make further investments in GHG abatement or purchase offsets instead of pay the tax in future years, especially as the emission limit tightens and the tax rises, and Teck can be expected to do so if the costs of these alternatives to the tax are lower. However, for modeling purposes I assumed the costs of abatement and offsets are equal to the carbon tax. I also assumed that Alberta's policy satisfies federal carbon pricing requirements (Alberta 2017b) and thus that the Teck project does not face an additional federal carbon tax liability. Lastly, I assumed that the Project does not incur any further liability associated with Alberta's 100 megatonne cap on oil sands emissions (the oil sands industry is currently emitting about 70 megatonnes per year).

To address damage costs incurred by society for the Project's GHG emissions independent of the carbon tax I multiplied emissions by the social cost of carbon (SCC) which is intended to reflect the monetary impact of GHG emissions on society. I relied on SCC values of the Government of Canada (ECCC 2016).[17] In my base case I applied the Government of Canada's "updated central" damage cost factors, which leads to average GHG damage costs during operations of $317 million and total Project GHG damage cost of $5.5 billion (NPV).[18] Given that there is substantial uncertainty about the SCC (Tol 2013), I also ran my model with the Government of Canada's "updated 95th percentile" factors which reflect the potentially catastrophic impacts of climate change. These 'high risk' damage cost factors may even be conservative given that climate change is progressing more rapidly than previous thought (e.g., Le Page 2018).

I also ran my model in two other ways to explore the potential magnitude of the Project's GHG damages.

To address the damages associated with downstream emissions induced by the Project, under the notion that the Project leads to not just to incremental production-related

[17] There are different SCCs for different types of GHGs; however, given that the vast majority of emissions will be carbon dioxide (CO_2). I used the SCC for CO_2 for all Frontier emissions.

[18] ECCC provides GHG damage cost factors from 2016 to 2050 yet the Project's lifespan lasts much longer. To mimic the rate of appreciation in these factors over this period I estimated the slope of the increase in the factor over time and then extrapolated through to the end of the Project's life.

emissions but also to incremental consumption of refined petroleum products and associated downstream emissions that wouldn't otherwise happen, I valued not just the emissions at the Project site but also emissions associated with transport of Frontier bitumen to refineries, refining, distribution of resulting refined petroleum products (RPPs), and combustion by end-users. Prior to estimating these damages I first accounted for volume changes in refining and the final product mix from crude oil by scaling Frontier bitumen deliveries according to Canadian refinery data.[19] I then used GHG emission factors for downstream steps from IHS CERA (2010)(Table 4) and multiplied the resulting emission volumes by my base case SCC (ECCC's "updated central" SCC value). I estimate that downstream emissions during operations are over seven times greater than upstream emissions and thus pose a significant climate change impact of the Project.[20]

Table 4. Downstream GHG emission factors and damage costs.

	Crude Transport	Crude Refining	Distribution of RPPs	Fuel Combustion	Total
GHG emission factors from IHS CERA (kg CO_2e per barrel)	6	70	2	384	462
Average emissions over operational years (t CO_2e per barrel)	359,553	4,576,131	137,284	25,103,347	30,176,315
Average damage costs over operational years[2]	$28 million/yr	$355 million/yr	$11 million/yr	$1.9 billion/yr	$2.3 billion/yr

Note: 1. Emission factors pertain only to the volume of oil or RPPs that advance to each step in the downstream supply chain. For example, the distribution emission factor is only applied to the volume of RPPs that are derived from Project crude oil output. 2. Damage costs calculated using ECC's "updated central" SCCs. Source: IHS CERA (2010).

[19] Based on Canadian refining data, there is a 6% volumetric gain in refining but only about 83% of refinery outputs become combustible fuels which mathematically works out to an 87% scaling factor (STC 2011).

[20] My wells-to-wheels emission estimates may be low, though, thus under-costing the Project's total GHG emission responsibility. Applying Swart and Weaver's (2012) wells-to-wheels emission factor for surface mining and upgrading yields emission totals during operation years that are 17% greater than what I estimate.

Finally, to address the notion that the scope of analysis – Canada in the case of my model – should be consistent across all impacts assessed, including GHG damages (Bennett 2014; Heyes et al. 2013), I ran my model in sensitivity analysis to include only the damages that would occur to Canadians on a population basis. Such a restricted scope dramatically reduces the damage costs of the Project counted in the analysis because Canada's population is but 0.5% of the global population. This scenario runs counter to standard social cost of carbon accounting and effectively ignores most of the climate change damage caused by the Project.

In summary, the Project's GHG emissions will cause damage costs to Albertans, other Canadians, and citizens of the world. I estimated these emissions from Teck and supplementary information and then multiplied emissions by estimates of the social costs of carbon from the Government of Canada. To account for uncertainties as to the damages of GHG emissions I conducted two sensitivity analyses. I also estimated Alberta carbon tax revenues which will be used by the Government of Alberta to help address climate change. Overall my findings challenge Teck's conclusion (2015 Application, Volume 3, p4-4) that the Project's emissions are quantitatively minor in provincial and national emission contexts.

6.10 Water Resources

Like other bitumen development projects, the Frontier project raises concerns in terms of consumption and contamination of fresh water resources, and these costs need to be accounted for in impact assessment. For many years, stakeholders and scientists have been voicing concerns about water use by bitumen developers and water contamination (Gosselin et al. 2010; Hebert et al. 2013; Kurek et al. 2013; NRTEE 2010; Timoney 2007; Woynillowicz et al. 2005). These concerns led government and industry to develop three regulatory frameworks:

- the *Surface Water Quantity Management Framework for the Lower Athabasca River* (Alberta 2015), which replaced a 2007 water management framework and established new rules for water withdrawals by bitumen developers and thereby established the basis for cumulative effects management of Athabasca River water quantity;
- the *Surface Water Quality Management Framework for the Lower Athabasca River* (Alberta 2012b), which provides the basis for cumulative effects management of water quality along the Athabasca River by setting triggers and limits for 38 water quality indicators measured at the Old Fort monitoring station near the entrance of the Athabasca River to Lake Athabasca; and
- the *Groundwater Management Framework for the Lower Athabasca Region* (Alberta 2012a), which lays the framework for cumulative effects management of groundwater.

According to Teck, the Project will consume fresh water, mostly from the Athabasca River (2015 Application, Volume 1, pp 7-1 and 14-17), and the Project will affect the local hydrological regime but only negligibly beyond Embarras Portage near the entrance of Lake Athabasca (2015 Application, Volume 3, p6-8). Teck concludes that the Project will comply with the *Surface Water Quantity Management Framework for the Lower Athabasca River* (2015 Application, Volume 1, p7-48; 2015 Application, Volume 3, p6-75). While I understand that some stakeholders challenge Teck's conclusion, for the purposes of my analysis I accept Teck's conclusion as I do not have sufficient basis to do otherwise. However, if Teck's conclusion is wrong then there would be negative effects that would need to be counted in the CBA.

With respect to water quality, Teck has various plans and design features intended to contain all contaminated water, though Teck admits that a small amount of pollution will inevitably make it out of the Project site and into regional waterways (2015 Application, Volume 1, p7-36) with potential effects on country food consumed by Aboriginals and others. Teck plans to contain all contaminated water onsite until the end of the Project's life when the water is expected to be sufficiently clean that it can be released to the Athabasca River (2015 Application, Volume 1, p13-1). Teck concludes that the Project will have

> *negligible effects on acute and chronic toxicity, and tainting potential concentrations in all receiving waters… negligible effects on aquatic health in Ronald Lake, Redclay and Big creeks and the Athabasca River" (2015 Application, Volume 3, p7-2).*

As part of its mitigation plans, Teck states that it will engage and participate in research on reclamation and water resource management in the region (2015 Application, Volume 1, p13-151) as well as surface water and groundwater monitoring (2015 Application, Volume 1, pp 14-26 and 14-27).

Regardless, stakeholders in the region, especially Aboriginal people living downstream of bitumen development such as the Athabasca-Chipewyan First Nation, are concerned about water quality in the Athabasca River and other regional waterbodies and waterways, especially given monitoring results finding evidence of water quality degradation (Candler et al. 2014; MCFN & ACFN 2017). These concerns and the resulting changes to harvesting and other cultural practices are real effects from a CBA perspective. I am not aware of any studies that have been done in the oil sands region estimating the monetary value of the bitumen industry's water impacts, but many such studies have been done elsewhere (CCME 2010). Beyond issues of clean water rights and Indigenous rights which are not appropriately considered in monetary terms, these impacts on water are a cost that could be included in a CBA of the Frontier project should the magnitude of the cost be known. I include water quality effects of the Frontier project as a non-monetized but still important cost of the Project in my conclusion.

In summary, the Project will have impacts on water resources, both in terms of water quantity and quality. Due to technical and methodological barriers I have not estimated a monetary damage cost associated with these impacts on water, but these costs still exist.

6.11 Ecosystem Services

Ecosystem services are the benefits people obtain from ecosystems (MEA 2005). As the Frontier project will substantially alter 29,217 hectares of landscape over the Project's multi-decade lifespan (2015 Application, Volume 1, p13-2), and possibly longer if reclamation isn't successful, there will be a loss of ecosystem services with an attendant cost to society. I have already discussed market effects of changes at the Project site in s.6.7 with respect to impacts on forestry and trapping, but there are additional non-market values that need to be counted such as:

- the change in provision of climate regulation, water stabilization and regulation, and erosion control services from the site's vegetation;
- the change in the site's contribution to soil formation, pollution absorption, and pollination services;
- the change in the site's capacity as habitat, including for rare and endangered species;
- the change in the site's capacity to provide country food and other raw materials (e.g., for traditional medicines); and
- the change in the site's recreational and cultural value, especially for Aboriginal groups in the area but also for non-Aboriginals.

In addition, site alteration may have effects on ecosystem services beyond the site boundaries. For example, some species may experience edge effects whereby habitat quality is not just a function of the land beneath a creature's feet but also a function of adjacent land. Similarly, the recreational and cultural value of lands is often not just a function of the lands a person stands on but the lands adjacent.

Teck assesses these topics directly or indirectly in various parts of its EA application, but regardless of Teck's conclusions on whether or not the effects will be 'significant' or not in the sense contemplated in the EA, incremental effects on ecosystem services still need to be counted in any CBA of the Project. Table 5 summarizes Teck's estimates of the number of hectares (ha) of pre-disturbance, closure area, and net change of ecosystem types; I use Teck's estimates of landscape change to estimate effects on ecosystem services.

Table 5. Teck predictions of net changes in ecosystem type over the course of Frontier project life.

Ecosystem Type	Pre-disturbance Area	Net Change	
Uplands	14,400 ha	+2,970 ha	+10%
Wetlands	14,096 ha	-8,489 ha	-28%
Littoral	0 ha	+886 ha	+3%
Submerged berms	0 ha	+215 ha	+0.1%
Freshwater bodies	0 ha	+3,780	+13%
Disturbed lands	721 ha	-721 ha	-3%

Source: 2015 Application, Volume 1, p13-76.

At present, the Project site is used for forestry, trapping, and traditional harvesting, but also provides a range of other ecosystem services (e.g., carbon sequestration, wildlife habitat). Using ecosystem services values for uplands and wetlands that have been used in several prior Canadian studies in the boreal forest (Table 6), the existing site provides approximately $24 million (2017CDN) in benefits annually.[21] For the purposes of my CBA, I assumed that these annual ecosystem services benefits would be fully lost over each year of the Project lifespan but then benefits would resume by 2082 when the Project is completed (2015 Application, Volume 1, p13-6). However, I estimate that the Project site would provide only $18 million in ecosystem services benefits per year following reclamation because some wetlands will be converted to uplands over the course of the Project.

Table 6. Value factors of boreal ecosystem types.

Ecosystem Type	Value ($2017CDN/ha)
Forests	$64.96
Wetlands	$1,632.32

Source: Anielski (2012).

My estimate of the ecosystem services losses over the Project life may underestimate actual ecosystem services damages for four reasons.

- First, undisturbed nature is becoming rarer over time, and thus I would expect the value of nature to rise over time, something which isn't accounted for in my analysis given that I use static ecosystem services value factors.

[21] Under the assumptions that: (a) uplands are currently used for forestry and thus provide only a portion of the value of undisturbed boreal forests; (b) Teck's classifications of littoral, submerged berms, and freshwater bodies provide the same value as wetlands; and (c) disturbed lands provide no benefits.

- Second, the ecosystem services value factors that I use may underestimate the value of the Project site. Teck concluded that the Project's impact on regional losses of peatland were of "high environmental consequence" (2015 Application, Volume 1, pp 18-83 and 18-99) due to the current inability to reclaim this type of wetland (2015 Application, Volume 1, pp 13-148 and 18-79), the importance of peatland as habitat for boreal caribou and various bird species, and the importance of wetlands for traditional use (2015 Application, Volume 1, pp 13-141, 13-142, 13-144, 13-147). As well, the Project site provides habitat for species-at-risk (2015 Application, Volume 1, p13-139), including caribou. Yet as Anielski (2012) notes, "[a]ny value for [ecosystem services] for wetlands should reflect the relative importance and scarcity of specific wetland areas in the context of watersheds or other large-scale ecosystem zones" (15). The same issue pertains to valuation of uplands. As the ecosystem services value factors provided by Anielski (2012) reflect average Canadian boreal landscapes, the special significance of the lands lost with Frontier may not be captured in my ecosystem services damage estimates.
- Third, while the ecosystem services value factors used include components for food production and culture, monetary representations of value cannot be expected to capture the full range of values of natural and culturally-important assets. The Frontier project site is part of the traditional territories of several Aboriginal groups in the region and is highly valued by these groups, especially given the current context of high levels of development. Teck's conclusion is that the Project will contribute to "high consequence" cumulative effects on traditional land use (2015 Application, Volume 1, p18-133). Monetary valuation cannot capture the many dimensions and full nature of these impacts. Along the same lines, infringements of human rights (such as to clean water, or to the ability to practice traditional activities) is not amenable to monetization because the two concepts aren't compatible (Sagoff 1988). Under growing international but also domestic conceptions and law, various rights may be infringed upon with development of the Frontier project site, and so ecosystem services value factors are not capable nor are suited to capturing these issues.
- Fourth, as already mentioned there is uncertainty about how successful oil sands mine reclamation will end up being (s.6.4). If reclamation is unsuccessful in any way then there will be further lasting losses of ecosystem services.

In summary, the Project will cause impacts on the Project site's and adjacent lands' ability to provide ecosystem services, and I have made an estimate of these costs using Teck's project footprint information and monetary estimates of the value of Canadian boreal forest. However, I identify four reasons why my estimate of ecosystem services losses may be an underestimate. Teck covers many ecosystem service issues throughout the Frontier EA application but does not conduct an analysis similar to what I have done.

6.12 Other Impacts

User Costs. The Frontier project's production of oil constitutes consumption of natural resources. Unless this *natural capital* is converted to other forms of capital – capital being a means to earn income – the Project does not earn true income but instead constitutes liquidation of capital and imposes what economists refer to as a user cost. In a past study of the Kearl bitumen mine I estimated an upper bound of the user cost of that project to be $29 million per year (Joseph 2013), with the key uncertainty being the level of investment by the project's developer and government of project proceeds into other forms of capital. As the potential user cost associated with Frontier would be appear to be relatively small, and as it is also uncertain how much private and government reinvestment of the proceeds of the Frontier mine will occur, I have not tried to estimate this cost.

Foreign Investment and Leakage. Foreign investment in the Canadian oil sector is very common, and this can mean incremental investment and associated royalty and tax revenue that wouldn't otherwise occur, but it also means that profits may be leaked (i.e., accrue) to foreigners. In a past study of the Kearl bitumen mine (Joseph 2013) I explored this issue and concluded that the gains and losses with foreign investment might cancel each other out. Likewise, for the Frontier mine it's nonetheless important to consider that while any foreign holders of Teck shares bring money into Canada that might not otherwise come to Canada, these shareholders also draw profits out of the country. I did not try to estimate foreign investment and leakage effects associated with Frontier.

Subsidies to the Fossil Fuel Industry. Senior governments in Canada have invested substantially in the fossil fuel industry (McLeod-Kilmurray and Smith 2010), including the recent investment in the Kinder Morgan Trans Mountain Expansion project, and for a long time governments have also subsidized the oil industry through tax breaks and other means (Dillon et al. 2008; EnviroEconomics Inc. et al. 2010; Environmental Defence Canada 2016; Taylor et al. 2005; Touchette 2015). These are costs borne ultimately by taxpayers and thus are costs that should be accounted for when assessing the net benefits of an oil project. However, due to the challenge of determining the actual amount of subsidy that the Frontier project may receive I have not tried to estimate this for my CBA.

Social Costs. Major project development is often associated with numerous community and other 'social' impacts, and oil sands development is no different. Teck reviews potential social impacts in its application, such as population pressure in Fort McMurray, and associated pressure on housing, traffic, infrastructure, and services (2015 Application, Volume 1, s.16). Beyond examining the issues of incremental employment and incremental tax and royalty revenues to government, incremental costs to government, as well as a discussion particular to potential effects on Aboriginal groups below in s.6.14.3, I have not tried to account for any other social impacts in my CBA. In many cases, social impacts are not amenable to monetization and instead are more suited to other forms of impact assessment. As such, I simply note that my CBA is not complete in this regard.

6.13 Discount Rate

A critical part of assessing the impacts of projects that span long periods of time is consideration of the fact that gains or losses in the future are not worth the same to people as gains or losses today. There are two main reasons for this: (1) people have an inherent tendency to prefer benefits sooner rather than later and to defer costs, and (2) the greater interest that can be earned when investments are made sooner. By converting all monetary values into a common temporal unit – a process called discounting – a project's net present value (NPV) can be calculated, where NPV is the discounted sum of a project's benefits and costs over the project's lifespan. However, discounting has the effect of diminishing future impacts, which in the case of environmental and health issues and thus from sustainability and intergenerational ethics points of view is problematic. Despite substantial effort, economists and philosophers have not resolved these conflicts, and may never do so.

Regardless, discounting is a real phenomenon, and so the challenge is identifying an appropriate discount rate, rates, and/or approaches to use. There are two main issues to consider when discounting the impacts of Frontier: investors' private opportunity costs of capital, and the sustainability implications of the Project.

Investors require a reasonable return on investment, and so from this point of view a discount rate reflective of what investors could earn elsewhere makes sense. Teck used an 8% discount rate in some of its calculations (2015 Application, Volume 1, pp 16-13 and p16-14), which is what the Treasury Board of Canada Secretariat recommends in its most recent CBA guide (TBCS 2007) for CBAs of regulatory change. CERI uses a 10% rate in its supply cost studies (e.g., Millington 2017) to examine private investment in the oil sands, and while the AER doesn't indicate what discount rate it used in its most recent supply cost study (AER 2018) its predecessor used 10% (ERCB 2011). In its 2014 refinery CBA, CERI (Millington et al. 2014) used 15% as a base case rate, with rates of 13% and 17% for sensitivity analyses. CERI argued that 15%, while above the traditional cost of capital, "is based on the assumption that the project proponent is not a vertically-integrated company" and as the building of the project in question (a new refinery) "faces market entry challenges and risks" (p29). These relatively high rates used by CERI reflect the particular project they were evaluating and is less relevant for the Frontier project. Regardless, discount rates reflecting how investors value future costs and benefits tend to be 8% or higher, and this fact influences how the Project's future impacts are discounted.

Yet from a sustainability perspective, much lower discount rates are often advocated and used (Boardman et al. 2011; Freeman and Groom 2016; Hanley and Spash 1993; Kula and Evans 2011; Sáez and Requena 2007; Shaffer 2010). For example, the UK Stern Review on climate change adopted a 1.4% discount rate, and other climate change economics studies have applied rates on the order of 3% (Goulder and Williams III 2012). CBA is premised on people's actual valuations (Shaffer 2010), and future environmental quality and human health are generally discounted little or even valued more by people (Gowdy 2004; Luttrell 2011; Sáez and Requena 2007). From this standpoint, a low rate should be used in the Frontier CBA given the Project's environmental impacts and associated impacts on health such that these impacts are diminished relatively little by the mathematical effects of discounting and reflect how people view such impacts.

With these contrasting considerations in mind – the expectations of investors but the sustainability issues raised by the Project – I tested the Project's value to society under several discounting scenarios. For my base case I adopted a dual discounting approach (e.g., Brouwer et al. 2005; Freeman and Groom 2016; Kolosz and Grant-Muller 2015; Kula and Evans 2011; Luttrell 2011; Postma et al. 2013; Sáez and Requena 2007) in which market impacts (e.g., oil revenue, CAPEX, etc.) are discounted at 10% to be more consistent with private opportunity costs of capital and oil sands supply cost studies, and environmental impacts at 3% reflecting sustainability concerns. I also ran my model with uniform 3%, 8%, and 13% rates.

6.14 Results

6.14.1 Base Case

I estimate the base case NPV of the Frontier project to be a net loss of $4.6 billion to society (Table 7) under the base case parameters shown in Table 8. Note, though, that the base case NPV result does not factor in several unmonetized impacts on air quality, water resources, certain ecosystem services, the risk of reclamation failure, and the social costs associated with government subsidies. These unmonetized impacts would act to reduce the NPV result further, though impacts on water resources may be more appropriately considered outside of the domain of economic methods due to potential human rights concerns.

Table 7. Key results of base case.

Indicator	Result
Social NPV	$4.6 billion net loss
Private IRR	7.8%

From a private perspective, in which environmental impacts are ignored but royalty and tax transfers are relevant, the Project generates only an internal rate of return of 7.8% in the base case (Table 7), which is low from a private investment perspective. CERI, for example, required a 10% return for investors in their oil sands supply cost study (Millington 2017). While the Project would earn substantial oil revenues for investors, the Project's construction and operational costs, royalties, and taxes are also substantial and contribute to a low expected return. In other words, investors should do better investing elsewhere. This finding supports the NEB's and IEA's conclusions that oil prices will be too low to encourage new investment in mines in the oil sands (see s.6.3). This finding also raises the concern that low financial earnings may affect Teck's commitment to mitigation of the Project's adverse effects – mitigation costs money, and with low revenues Teck's mitigation efforts may end up being less than ideal.

Disaggregated results for the base case are presented in Table 9. In terms of the base case NPV result, oil revenues are nearly outweighed by Project costs alone, never mind GHG damages and other environmental costs.[22] See s.6.14.3 for information on the distribution of benefits and costs of the Project by group.

[22] The values in Table 9 are rounded; the sum of unrounded CAPEX, OPEX, and reclamation costs sum to just under the estimated oil revenues.

Table 8. Key parameters used in the Frontier CBA.

Parameter	Unit	Base Case Value	Alternative Values Tested in Sensitivity Analysis
years of operations	years	41	-
maximum nominal production capacity	bpd	260,000	-
production capacity utilization factor	%	88	-
oil price scenario	2017CDN$/bbl	NEB 2017 Reference ($69.69 WTI in 2018 rising to $92.13 WTI in 2027 and remaining there until 2066)	NEB 2017 Technology ($70.70 WTI in 2018 declining to $75.50 by 2040 and remaining there until 2066) IEA 2017 New Policies ($56.23 IEA Crude in 2018 rising to $124.00 in 2040 and remaining there until 2066)[1]
bitumen price differential	2017CDN$, %	WCS price minus $1.89 in transportation costs between mine and Hardisty (leading to bitumen prices of $42.10 in 2018 rising to $63.59 in 2027 and continuing to rise to $68.79 in 2036 and then remaining there until 2066)	60% bitumen:WTI (leading to bitumen prices of $41.81 in 2018 rising to $55.28 in 2027 and remaining there until 2066)

Parameter	Unit	Base Case Value	Alternative Values Tested in Sensitivity Analysis
CAPEX	2017CDN$	$23.4 billion (based on $90,000 per barrel capacity)	$21.5 billion (Teck's 2015 estimate) $32.2 billion (25% increase over the base case)
annual OPEX at full operations	2017CDN$	$2.2 billion	+/-25% (leading to OPEX of $2.3 billion or $2.1 billion)
total reclamation costs	2017CDN$ undiscounted	2% of CAPEX: $429 million	Foote (2012): $4.1 billion
employment benefits	n/a	None	10% of labour otherwise unemployed
air pollution damage costs: - NO_x - SO_2 - $PM_{2.5}$ - VOCs	2017CDN$/t	Muller and Mendelsohn (2007): - $451 - $1,353 - $1,654 - $451	Jaramillo and Muller (2016): - $6,136 - $23,487 - $53,608 - not available
GHG damage cost factor	2017CDN$/t CO_2	ECCC's "updated central" values ($46.00 in 2018 rising to $80.15 in 2050 and remaining there until 2066)	ECCC's "95th percentile" values to represent the 'high risk' of catastrophic climate change ($191.75 in 2018 rising to 342.66 in 2050 and remaining there until 2066)

Parameter	Unit	Base Case Value	Alternative Values Tested in Sensitivity Analysis
GHG emissions scope	n/a	Emissions associated with Project construction through to and including operations; damages to globe	Emissions associated with Project construction through to and including final consumption, damages to globe Emissions associated with Project construction through to and including operations; damages only to Canadian portion of global population
Ecosystem service damage cost factors: - forest lands - wetlands	$2017CDN/ha	$64.96 $1,632.32	-
discount rate	%	10% for market impacts and 3% for environmental impacts	uniform rates of 3%, 8%, and 13%

Note: 1. The IEA doesn't provide a forecast in WTI terms and instead provides a forecast only for a crude blend.

Table 9. Project benefits and costs in the base case.[1]

Impact	NPV (2017CDN$)
Revenue benefits from oil production	$20.8 billion benefit
CAPEX	$10.7 billion cost
OPEX	$8.4 billion cost
Reclamation	$2 million cost
Employment benefits	No incremental benefit
Government costs	Cost (unmonetized)
Impacts on other commercial activities	Cost (accounted for in CAPEX and OPEX)
Air pollution	$121 million cost plus additional cost associated with unmonetized pollutant exposure
GHG damages	$5.5 billion cost
Impacts on water resources	Cost (unmonetized)
Impacts on ecosystem services	$699 million cost
Other impacts: • user cost • foreign investment • subsidies • social costs	 • Cost (unmonetized) • Unknown if benefit or cost • Cost (unmonetized) • Unknown if benefit or cost

Note: 1. Values are rounded up.

6.14.2 Sensitivity Analysis

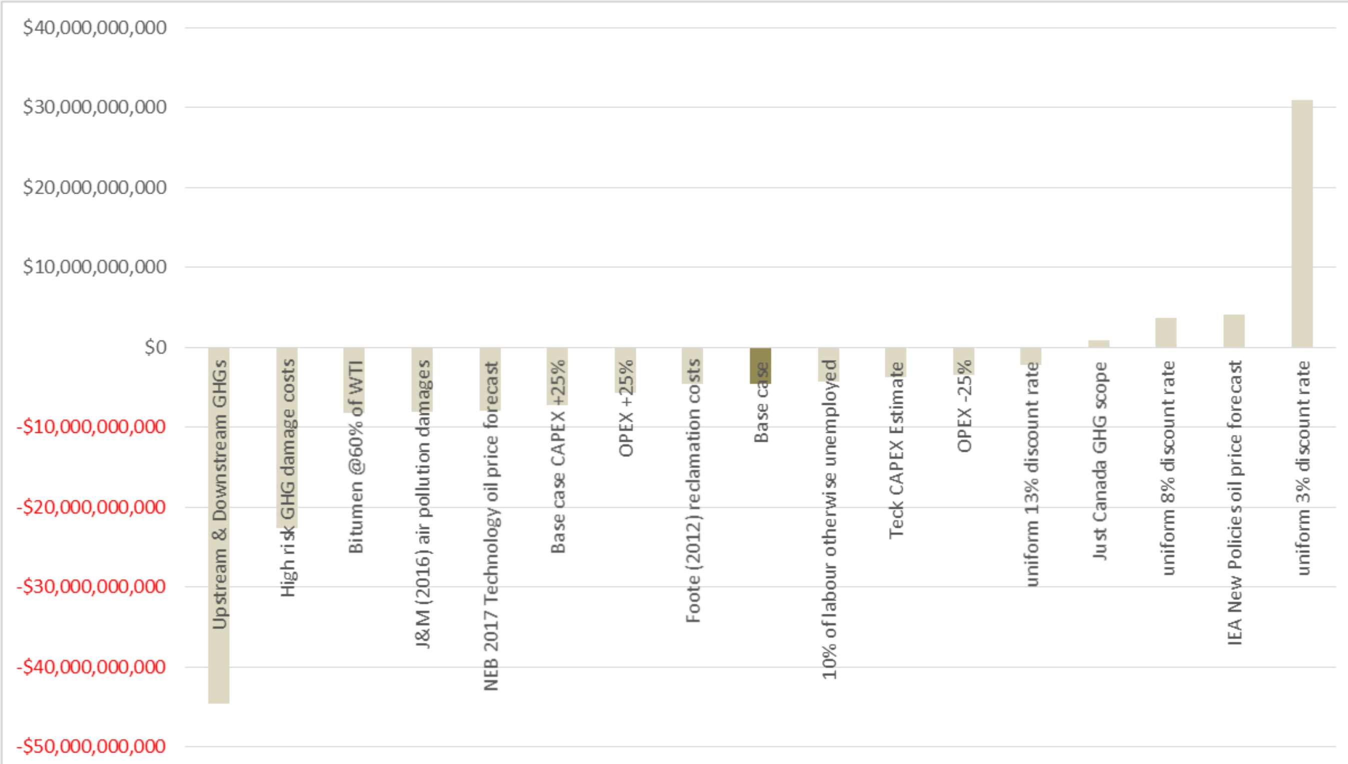
There is uncertainty with respect to some of the input parameters used in the CBA, and therefore it's critical to assess the robustness of model results against variation in input parameters by completing sensitivity analysis. Across the range of scenarios assessed, NPV varies between a low of -$44.5 billion to a high of $30.9 billion (Table 10; Figure 3), though most scenarios tested do not vary so much from the base case results.

Table 10. Comparison of net present values across the base case and sensitivity analysis scenarios.

Scenario	Rationale and/or Explanation	Net Present Value ($2017CDN)	Difference in Net Present Value from Base Case ($2017CDN)
Upstream & Downstream GHGs	Includes all GHG emissions associated with Project output	-$44.5 billion	$40 billion less
High risk GHG damage costs	ECC's "updated central" carbon damage estimates may under-represent the potentially catastrophic impacts of climate change	-$22.6 billion	$18 billion less
Bitumen @60% of WTI	Uncertainty about value of bitumen relative to marketable crude oil	-$8.2 billion	$3.6 billion less
J&M (2016) air pollution damages	More recent study that finds much higher damages associated with air pollution	-$8.1 billion	$3.5 billion less
NEB 2017 Technology oil price forecast	Uncertainty in future oil prices – this scenario anticipates relatively low future prices	-$7.9 billion	$3.3 billion less
Base case CAPEX +25%	Uncertainty about costs of construction – this scenario assumes substantial cost growth	-$7.2 billion	$2.7 billion less
OPEX +25%	Uncertainty about costs of operations – this scenario assumes cost growth	-5.7 billion	$1.1 billion less
Foote (2012) reclamation costs	Uncertainty about costs to reclaim bitumen mine sites – this scenario assumes higher costs	-$4.6 billion	$20 million less
Base case	-	-$4.6 billion	-

Scenario	Rationale and/or Explanation	Net Present Value ($2017CDN)	Difference in Net Present Value from Base Case ($2017CDN)
10% of labour otherwise unemployed	Possibility that some Project workers would otherwise be unemployed	-$4.3 billion	$292 million more
Teck CAPEX Estimate	Assumes that Teck's estimate of construction costs is accurate	-$3.7 billion	$883 million more
OPEX -25%	Uncertainty about costs of operations – this scenario assumes lower costs than currently anticipated by proponent	-$3.5 billion	$1.1 billion more
uniform 13% discount rate	Debate over the appropriate rate at which people value the present vs. the future – the 13% rate assumes that people value the present much more than the future	-$2.3 billion	$2.3 billion more
Just Canada GHG scope	Excludes GHG damages to rest of globe	$854 million	$5.4 billion more
uniform 8% discount rate	Debate over the appropriate rate at which people value the present vs. the future – the 8% rate assumes a moderate time-value of money	$3.7 billion	$8.3 billion more
IEA *New Policies* oil price forecast	Uncertainty in future oil prices – this scenario anticipates relatively high future prices	$4 billion	$8.6 billion more
uniform 3% discount rate	Debate over the appropriate rate at which people value the present vs. the future – the 3% rate assumes that people value the future much more	$30.9 billion	$35.5 billion more

Figure 3. Net present values of base case and sensitivity analysis cases – net present value.



Key conclusions that follow from the sensitivity analysis are as follows:

- The Project's value to society is highly contingent upon how one values GHG emission damages. The inclusion of downstream emissions under the assumption that the Project creates incremental refined petroleum products for the world to combust leads to the highest social cost result for the Project, and if one assumes that only upstream emissions are incremental but adopts the Government of Canada's SCC values that reflects the risk of catastrophic climate change then the second worst result is obtained.
- The Project's value is highly sensitive to oil price and project cost. The Project's financial viability in particular revolve around future oil prices as well as the high capital and other costs of the Project. If either the NEB's *Technology* oil price scenario or greater CAPEX or OPEX or reclamation costs come to fruition on their own the Project's social costs will rise significantly. If OPEX ends up being 25% lower than Teck forecasted for its 2015 application or Teck's CAPEX estimate in its application is correct – neither of which seem likely – the Project will still be a net social loss under all other base case assumptions. From a private perspective, my model indicates that an acceptable return on investment will only occur under a high oil price future

which seems unlikely given increasingly stringent carbon policy and electrification of automobiles.

- The Project's value to society is highly sensitive to assumptions about how people value the future. The Frontier project's value to society depends heavily upon what discount rate is assumed. A high rate diminishes the magnitude of impacts in the future (such as GHG damages and oil revenues), and a low rate diminishes such impacts much less-so. Under the base case dual discounting procedure (10% for market impacts and 3% for environmental impacts) the Project generates a $4.6 billion net social loss. The Project is also a net social and net private loss if one assumes a uniform 13% rate, which is a rate that more closely reflects the private investor perspective. Under a uniform 8% rate the Project is a net private loss of $218 million but a net social gain of $3.7 billion, but an 8% rate is inappropriately high when considering long-term environmental impacts. Adopting a uniform 3% rate leads to a high NPV for the Project – a strong net social and net private gain because the volume of the project's oil revenues grow enough to outweigh the project's financial and environmental costs – but this rate is counter to typical private investor expectations. I contend that the most appropriate discounting procedure – which I adopted for my base case – is to discount market impacts at a rate consistent with private investor expectations and to discount environmental impacts at a rate reflective of sustainability concerns.
- From a private investor point of view, the Project's financial outlook is poor. Under the base case my model predicts a private IRR of 7.8%, signifying a low return relative to typical investor expectations return.[23] If a variety of conditions hold on their own – i.e., if bitumen value at the minehead is but 60% of the WTI at Cushing price, if future oil prices follow the NEB's *Technology* forecast, if CAPEX rises a further 25%, or if OPEX rises 25% higher than Teck estimated – then even lower returns would be earned by investors. If more than one of these conditions hold, then the return for investors is worse. While more favourable conditions may come to fruition, the aforementioned scenarios are consistent with the NEB's and IEA's expectations that market conditions do not favour new investment in oil sands mines.
- The employment benefit to labour is small to nil. Labour market data strongly suggest that there would be no incremental benefit to labour from the Project, but even under the assumption of 10% of employees otherwise

[23] The IRR is not a function of the discount rate but *is* the discount rate at which investors would turn a profit. The $2.2 billion private loss in the base case reflects the 10% discount rate for market impacts used in the base case.

unemployed the Project's value increases only slightly. This finding is in stark contrast to Teck's predictions (discussed in s.5.1) of hundreds of thousands of job 'benefits' and billions of dollars of labour income 'benefits' (despite their admission elsewhere in their EA application that there may be few incremental employment benefits – see s.6.5). As discussed in s.5.2, Teck's method ignores what labour would otherwise be doing and thus provides only a limited picture of the net economic benefits of the Project.

6.14.3 Distributional Analysis – Base Case

An important component of any good practice CBA is an assessment of the distribution of costs and benefits. For this study I report benefits and costs by key stakeholder group under base case assumptions (Table 11). Note that while Aboriginal groups such as the Athabasca-Chipewyan First Nation are not differentiated in my table from other people, Aboriginal groups will be affected indirectly by way of effects on government, as regular citizens, but also in the manner in which Aboriginal people are uniquely affected due to the cumulative effects of the Project and other development and events back through to colonization on traditional territory and associated cultural activities. CBA is limited in terms of its ability to capture the project effects that related to cultural and rights-based issues, and so I discuss effects on Aboriginal groups in more detail in a separate subsection below.

Table 11. Incremental benefits and costs flowing to stakeholders (base case scenario).[1]

Stakeholder	Impact	NPV ($2017CDN)
Private investors	Return on investment (net of Project revenue, Project costs, royalties and taxes owing)	$4 billion loss
Government of Alberta	Royalties, Alberta corporate income tax, property tax[2]	$3 billion gain
	Incremental government costs	Negative
	User cost	Negative
Government of Canada	Corporate income tax	$485 million gain
	Incremental government costs	Negative

Stakeholder	Impact	NPV ($2017CDN)
	Net effects of foreign investment benefits and leakage	Unknown
Externalities: Alberta	net GHG damages, air pollution, and impacts on ecosystem services [3]	$821 million loss
	Impacts on water resources	Negative
Externalities: Rest of Canada	net GHG damages [3]	$14 million loss
Externalities: Rest of World	net GHG damages [3]	$3.2 billion loss

Note: 1. Values are rounded. 2. Property tax flows to the Regional Municipality of Wood Buffalo, a local government in Alberta. 3. Net GHG damages are the net of GHG damage costs and climate change investments stemming from Alberta's carbon tax.

Under base case assumptions I estimate the private return on investment to be 7.8%. In NPV terms, I estimate that investors will incur a $4 billion (NPV) loss after tax and royalties at a 10% discount rate.

Assessing the fiscal impacts of projects on government is complex. Many studies count all tax revenue from a project as incremental while ignoring costs to government, resulting in a significant misrepresentation of impacts on government. A more accurate approach is to assume that sales tax, fuel tax, and labour income tax associated with the Frontier project is offset by government responsibilities to provide infrastructure and services to the Project and its employees (such as health care, roads, and policing). Furthermore, given the opportunity costs of Frontier's investment capital and labour (s.6.5), one can generally assume that such tax revenues would flow from alternative investments if Frontier did not proceed.[24]

As such, in the case of the Government of Alberta, the only incremental benefits of the Project are royalties, corporate income tax, and municipal property tax: these revenues would only otherwise be earned if one assumed that investors would build a different bitumen mine, which I don't consider likely given the limited bitumen resources available.[25] I estimate that these revenues will total $3 billion (NPV) in the base case.

[24] Note that while in the base case I argued that employment benefits were unlikely given current and anticipated future labour market conditions I did explore in sensitivity analysis the scenario in which 10% of Frontier employees would otherwise be unemployed. Under such a scenario there would also be incremental personal income tax revenue flowing to both the Alberta and federal governments.

[25] Carbon tax revenue is not counted as a benefit to the Government of Alberta because the government plans to invest all of this revenue into addressing climate change.

- Royalties are paid at a rate between 1% and 9% of gross revenues, depending on the price of oil, during the Project's 'pre-payout period', and then after 'payout' royalties are paid at the greater of this pre-payout rate or a rate between 25% and 40% on net revenues, again depending on the price of oil. Teck estimated the Project would pay total royalties of $46 billion (2014CDN undiscounted; 2015 Application, Volume 1, p16-13) to $47 billion (Information Request Package 5, p5-9), but this amount is contingent upon Project costs and revenues, which in turn is a function of oil prices. I estimate that the Government of Alberta will earn $31 billion (undiscounted), or $2.2 billion (NPV).
- Corporate income tax is payable on profits to the Government of Alberta. Teck estimated $7.9 billion (2014CDN undiscounted; 2015 Application, Volume 1, p16-13). I estimate this revenue stream to total $5 billion (undiscounted), or $388 million (NPV) under the assumption that the Alberta tax rate of 12% remains over the life of the Project.
- Property tax is earned by the RMWB, a local government within Alberta. Teck indicates that it will owe $68 million (2014CDN) in the year when production starts (2026) and that the annual amount owing will increase to $94 million when phase 2 becomes operational in 2038 (2015 Application, Volume 1, p16-13). In its Information Request Package 5 (p5-9), Teck estimates that Frontier's total municipal taxes will amount to $3.6 billion (undiscounted). I adopt Teck's more recent estimate of property taxes directly into my model. However, this estimate may be an overestimate given recent changes to Alberta's *Modernized Municipal Government Act* which seeks to reduce the scale of differentials between the tax rates paid by industrial users such as Teck and other property tax rates (Schofield et al. 2017). The change will reduce the 2017 ratio of 17.9:1 between the rural non-residential tax rate and the lowest rural residential tax rate to 5:1 through some mix of reducing the higher rate paid by industry, raising the low rate paid by rural residents, and reducing RMWB expenditures. It is unclear when the tax changes will take effect (McDermott 2018), or what the eventual industrial tax rate will be. The Project's financial viability will improve to the extent that Teck's property tax liability declines, but at the same time the RMWB's (and thus Alberta's) benefits will decline. I tested the effect of a 50% reduction in property taxes and found only a minimal improvement in the Project's financial viability and a minor reduction in Alberta's net benefits.

Carbon taxes are payable to the Government of Alberta from facilities emitting more than allowed amounts, as discussed in s.6.9. Teck estimated total carbon tax revenue of $635 million but this was under the old tax regime. I estimated that the government would bring in (and then invest in climate change mitigation or adaptation) $5.6 billion (undiscounted) or $2.2 billion (NPV).

As I discuss in s.6.6, I did not identify any special infrastructure or service investments of the Government of Alberta, though the Frontier project will lead to some unquantified regulatory and management costs to both the provincial and federal governments. The Alberta government will also incur some unquantified user cost to the extent that government does not reinvest all resource rent earned off the Frontier project into other forms of capital.

The Canadian government will earn corporate income tax on profits, incur incremental regulatory and management costs, and be affected by foreign investment. Teck estimated “federal income and capital taxes” of $12 billion (CDN; Information Request Package 5, p5-9); Teck does not clearly define exactly what taxes are included in this estimate. I estimated federal corporate income tax to amount to $6.3 billion (undiscounted), or $485 million (NPV), under the current tax rate of 15% under base case assumptions. I did not try to estimate incremental regulatory and management costs, and as I discussed in s.6.12 there may be a mix of benefits and losses associated with foreign investment in the Project.

The Project will cause a number of adverse effects that are externalized onto citizens of Alberta, the rest of Canada, and the world. Under base case conditions – including the Government of Canada’s “updated central” social cost of carbon which doesn’t reflect the risks of catastrophic climate change or capture the much larger emission volume downstream of the Project, but also factoring in the investments made by the Government of Alberta from carbon tax revenue that will offset some of the GHG damages – Albertans will be exposed to a portion of the net GHG damages of the Project, the air pollution impacts of the Project, and impacts on ecosystem services totalling $1.8 billion (undiscounted), or $821 million (NPV), excluding un-monetized air pollution and water impacts.[26] I estimate that the rest of Canadians will incur $33 billion (undiscounted), or $14 million (NPV), in net GHG damages after carbon tax investments and that the rest of the world will incur $7.4 billion (undiscounted), or $3.2 billion (NPV), in net GHG damages.[27]

[26] For the distributional analysis I assumed all air pollution costs being incurred by Albertans, but most of this damage will be borne by those in nearby communities in the oil sands region, and realistically some impacts may be incurred by people in Saskatchewan and the Northwest Territories depending on air movement patterns. I counted all impacts on ecosystem services as affecting Albertans, although some of these impacts will affect others outside of Alberta due to the broader geographic reach of certain ecosystem services. As for impacts on water resources, most impacts will be felt by Albertans though some will inevitably affect people in the Northwest Territories due to the direction of water flow.

[27] I distributed net GHG damage costs across Albertans, the rest of Canadians, and the rest of the world proportional to population. Using this method, Albertans and the rest of Canadians are subject to but 0.5% total of the GHG damages.

Effects on Aboriginals

Aboriginal people in the region may be affected in several ways by the Frontier project. Environmental impacts of the Project, including cumulative effects on top of the environmental impacts of other development in the region, may have direct impacts on Aboriginals practicing cultural and subsistence activities as well as on communities in the vicinity and downstream of the Project. As noted in ss. 6.10 and 6.11, the environmental impacts of the Project have particular meaning for Aboriginals in the region whose culture and well-being revolve around the natural landscape. In economics terms the issue is one of 'ecosystem services', but for Aboriginals the issue is a matter of culture and tradition, everyday activities that life depends on and revolves around, Aboriginal rights and title, and the history of colonization. These are serious matters, and economic methods of valuation are not well-suited to cataloguing and interpreting these impacts. As these impacts are fully not captured in my monetary cost estimates my CBA does not capture the full adverse effects of the Project.

The Project may also have a variety of socio-economic effects on Aboriginal groups in the region, such as with respect to cost of living and economic benefits. To address these effects, Teck has proposed a variety of mitigation measures such as:

- using a fly-in/fly-out lodge to house workers, reduce pressure on local housing and services, and reduce travel risks associated with daily commuting (2015 Application, Volume 3, s.16);
- providing firewood to Fort Chipewyan from non-merchantable timber from the Project site to reduce costs cost of living (2015 Application, Volume 3, s.17); and
- adopting a procurement and hiring strategy, including training and a contracting policy that promotes local business for future Project development and operations, to support the involvement of Aboriginal businesses and workers in the Project (2015 Application, Volume 1, s.16).

Teck says in its responses to supplementary information requests that it will also explore providing support for community initiatives and infrastructure and is committed to implementing a socio-economic monitoring plan to assess impacts, and Teck commits to further discussions with Aboriginal communities to better understand their concerns and to develop mitigation measures to address other potential adverse impacts. Teck states that it will attempt to incorporate these future commitments in a negotiated agreement with Aboriginal people or as stand-alone policies if an agreement cannot be reached.

Teck's proposals to address Aboriginal communities' concerns are constructive, but it is critical to note that Teck's approach to addressing Aboriginal concerns is based on statements of intent that may or not be met. In contrast, it is now standard practice to establish contractual arrangements between proponents, governments, and affected Aboriginal communities that legally obligate the proponent and/or government to implement specific measures as a condition of project approval. Such agreements go by many names; in Canada, the term impact and benefit agreement (IBA) is commonly used.

The common feature of IBAs is that they are a formal contract outlining the anticipated impacts of a project, the commitments and responsibilities of involved parties to mitigate adverse impacts, and provisions to ensure that affected Aboriginal communities receive a share of benefits from a project.

In Canada's mining sector, IBAs have become a standard part of corporate-Aboriginal relations. IBAs are often a final, legally-binding agreement that stems from an initial memorandum of understanding and is developed through consultation and negotiation between the proponent and Aboriginal government. As of 2012, Natural Resources Canada listed more than 180 agreements with Aboriginal peoples at various stages of the mining lifecycle (NRCan 2013).

IBAs are also legally required for project approval in some Canadian jurisdictions. For example, s.5.2 of the *Canadian Oil and Gas Operations Act* states that a Benefits Plan must be submitted to the Minister of Northern Affairs and Northern Development Canada by any proponent exploring or drilling for oil in Nunavut, the Northwest Territories, or the Arctic. Similarly, s.26.2.1 of the Nunavut Land Claims Agreement states that major projects may not go ahead in Nunavut without a signed IBA.

Although IBAs vary from project to project, they often include the following types of provisions:

- labour: preferential hiring for Aboriginals, fulfilling an agreed-upon number of Aboriginal employees; training for these jobs could also be provided through local classes and apprenticeships or with scholarships and bursaries;
- economic development: recognition and support of relevant local Aboriginal businesses through preferential contracting, as long as said businesses are cost competitive, efficient, and timely; possible partnerships and joint initiatives with Aboriginal businesses; the creation and use of a registry of Aboriginal businesses and monitoring of Aboriginal content to meet agreed-upon requirements;
- community support and affirmation of Aboriginal rights and historic/cultural connection to land: funding for youth, social programs, community projects, and/or and physical infrastructure; facilitation of on-going communication between parties through establishment of committee meetings;
- environment: establishment of environmental planning and monitoring committees; reclamation commitments; efforts to minimize activity in

culturally-important areas; agreement that the proponent will not apply for more permits after IBA negotiation has finished;

- financial: monetary compensation arrangements; fixed or variable cash payouts; funding agreements with an established monitoring committee; and
- commercial: project certainty through acknowledgement of adequate consultation; dispute resolution and enforcement clauses if either party were to break the contract; and confidentiality.

While Teck has stated it intends to negotiate an IBA, it is under no obligation to do so. I'm also not aware of any efforts between the Alberta government and Aboriginal groups to negotiate any IBAs. Without an IBA there is no guarantee that any intentions to offset adverse impacts and to provide community benefits to Aboriginal communities in the region will be met.

6.14.4 Comparison of Teck Benefits Assessment with CBA Results

Table 12 presents a comparison of Teck's predicted economic benefits with the results of my CBA. This comparison is not comprehensive with respect to the Project's economic effects but merely a comparison of my CBA results with the items raised in Teck's economic benefits assessment. Importantly, it must also be noted that the comparison is also constrained by the limited extent to which measures can be compared, e.g., GDP and NPV are distinct and generally incompatible perspectives of project economics.

Regardless, several points are evident from this comparison. First, Teck's large GDP and employment numbers are presented as massive benefits of the Project but these are gross impacts. From a net benefits perspective the Project's oil revenue is outweighed by the high costs of production (which includes labour costs in a tight labour market). Refer to s.5 for a discussion of problems with EconIA methods used by Teck. Second, Teck's estimates of government revenues are larger than mine with the exception of carbon taxes, primarily I presume due to different oil price forecasts and different assumptions of Project costs. Teck's estimate of carbon tax revenue is much lower than mine reflecting Teck's basing of its calculations on now-outdated Alberta policy.

Table 12. Comparison of Teck EconIA and respect results from my base case CBA.[1]

Item	Teck EconIA[2]	My CBA
Project expenditures	$12.3 billion in GDP "benefits" from construction, and annual average GDP "benefits" of	Costs of $23.4 billion and $2.2 billion annually to the economy for construction and operations, respectively. These

Item	Teck EconIA[2]	My CBA
	$1.5 billion during operations	expenditures are investments that couldn't otherwise be made.
Employment and labour income	94,300 person-years in construction employment and 4,100 person-years annually in operations employment $13.2 billion in household income for construction, and $2.2 billion annually in household income during operations	No incremental employment benefits, i.e., jobs and labour income would otherwise be attained and earned.
Alberta royalties	$46.8 billion	$31 billion
Alberta corporate income tax	$8 billion	$5 billion
municipal property tax	$3.6 billion	$3.6 billion
federal corporate income tax	$12 billion	$6.3 billion
carbon tax	$635 million	$5.6 billion

Notes: 1. All values undiscounted. 2. Values from Information Request Package 5 or from 2015 Application if unavailable from the former source. See s.5.1 in this report for an overview of Teck's predicted economic benefits.

7. Conclusions

Alberta and Canadian regulatory criteria emphasize that project proposals need to demonstrate that they are in the public interest. The information that Teck presents in its environmental assessment application does not accurately or comprehensively address this requirement.

Teck used a method of benefits assessment that is well-known in the economics profession to be deficient with respect to informing of net benefits. Teck used economic impact analysis based on input-output modeling to assess a subset of economic effects linked to investment. This method ignores constraints in the economy, such as limits to investment capital and labour supply, and ignores a range of economic effects, such as incremental government burdens and the health costs of pollution. Teck provides information on the expected adverse effects of the Project in their environmental assessment application but does not synthesize this information with economic benefits information to inform of the Project's public interest value.

Using the standard method from economics of project evaluation used around the world – cost-benefit analysis – I assessed the value of the Project to society and to private investors. My analysis found that under base case assumptions the Project will be a net loss to society of $4.6 billion (NPV) and a poor investment with an internal rate of return of 7.8%, suggesting that the Project is not in the public interest and not a good prospect for investors. Little if any employment benefits should be expected from the Project due to current and forecast labour market conditions, and as such the Project should not be expected to be in the public interest from the perspective of jobs. Furthermore, while my cost-benefit analysis does incorporate a variety of environmental impacts, there are several adverse impacts not captured in my analysis results due to technical or philosophical reasons, suggesting that my results overestimate the Project's value to society.

There are numerous uncertainties in any modeling of a Project's future value, yet my sensitivity analysis suggests that the Project will be a net loss to society under a range of scenarios. I tested different oil price scenarios, environmental damage cost scenarios, Project cost scenarios, discounting scenarios, and the possibility of employment benefits. Only four scenarios yield a positive net benefit to society: ignoring greenhouse gas damages outside of Canada, the adoption of 3% and 8% uniform discount rates applied to all impacts, and adoption of the high oil prices assumed in the International Energy Agency's *New Policies* oil price forecast. There are reasons to doubt the appropriateness and/or realism of these scenarios given that: it is standard practice to consider the global damages of greenhouse gas emissions, not just those occurring within a jurisdiction; a 3% discount rate is not consistent with private investor expectations; an 8% discount rate is not appropriate for long-term environmental impacts; and the International Energy Agency oil price forecast is unlikely given global climate change concerns, likely future carbon policy, and technological change.

Similarly, in sensitivity analysis I found that the Project would be a relatively poor investment in all scenarios other than four of the 17 scenarios I tested: if 10% of labour would otherwise be unemployed, if the Project's operational costs end up being 25% less than what Teck predicted in 2015, if Teck's 2015 capital cost estimate ends up being correct, or if the International Energy Agency's *New Policies* oil price scenario is realized. The evidence suggests that none of these scenarios are likely, and so overall my findings support the conclusions of both the National Energy Board and International Energy Agency that new bitumen mines are unlikely to be built due to their poor financial outlook.

From a distributional standpoint, my results suggest that the Project is a gain only to the Alberta and federal governments. For investors my analysis finds that the Project will be a loss, and for citizens of Alberta, Canada, and the world my analysis finds also that the Project will be a loss due to adverse environmental impacts. While Aboriginal groups in the region may experience some employment benefits with the Project, few economic benefits should be expected by these groups without concrete commitments by Teck in the form of contractual obligations contained in an impact-benefit agreement. Regardless, I expect the Project to affect Aboriginal groups through its contribution to the cumulative effects of other development in the region, further compromising not just the landscape and water but the cultural and social activities that depend on them.

My findings challenge Teck's message of billions in benefits to governments, businesses, workers, and households. My overall finding is that the Project is likely to be a net loss to society and a poor private investment. Even if the Project was developed, workers have at least equal opportunities elsewhere. These conclusions, on top of the Project's substantial environmental impacts, call into serious question whether this Project is in the public interest.

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Appendix A: Chris Joseph CV

Chris Joseph MRM, PhD

Box 1513, Garibaldi Highlands, BC, V0N 1T0, Canada
cjoseph@swiftcreekconsulting.com; 604-848-9804; www.swiftcreekconsulting.com

Expertise and Skillsets

- environmental assessment including the assessment of economic impacts, the impacts of energy development, and the theory of environmental assessment and cumulative effects
- environmental and ecological economics, including cost-benefit analysis and non-market valuation
- megaproject development and their valuation
- collaborative planning, multi-stakeholder engagement, and facilitation
- policy evaluation and policy implementation
- literature synthesis and surveying/questionnaires
- structured decision-making
- project management and group leadership
- instruction and communications

Education

PhD (Resource Management), 2006 - 2013
School of Resource and Environmental Management. Simon Fraser University
"Megaproject Review in the Megaprogram Context: Examining Alberta Bitumen Development"
Recipient of several scholarships and awards, including Canada Graduate Scholarship – Doctoral (SSHRC) 2006-2009

Masters of Resource Management, 2002 - 2004
School of Resource and Environmental Management. Simon Fraser University
"Evaluation of the B.C. Strategic Land-Use Plan Implementation Framework"

Bachelor of Science (Honours with Distinction; Geography), 1993 - 1998
University of Victoria
"The Impact of Rock Climbing on the Soils and Vegetation at the Base of Cliffs within Greater Victoria, British Columbia"

Professional Affiliations

International Association of Impact Assessment

International Association of Impact Assessment – Western and Northern Canada

Past membership with the Association of Professional Economists of BC, International Association of Energy Economics, the Planning Institute of BC, Canadian Institute of Planners, and Connecting Environmental Professionals

Summary of Professional Experience

2016 - present
Principal, Swift Creek Consulting, Squamish, BC

2016 – 2018
Senior Socio-economic Specialist, SNC Lavalin, Vancouver BC

2003 – 2017
Sessional Instructor and Teaching Assistant, SFU, Burnaby BC
Courses: REM 321 Ecological Economics, REM 356 Resource Management Institutions, GEOG 389 Political Ecology, HSCI 845 Occupational and Environmental Health

2010 - 2016
Associate, Compass Resource Management, Vancouver BC

2000 - Present
Owner, Chris Joseph Photography, Squamish BC
Photography and writing published in national and international publications, websites, and catalogues including Globe and Mail, Patagonia, Explore, Climbing, BC Paraplegic Association, Canada Science and Technology Museum, British Columbia Magazine, Mountain Equipment Co-op, Readers Digest, Ski Canada, Pique, Vancouver Sun, Westworld (BCAA), and National Post.

2003 - 2013
Researcher, Sustainable Planning Research Group, SFU, Burnaby BC

2005 – 2009
Independent Consultant, Vancouver BC

2005 – 2006
Research Associate, MK Jaccard & Associates, Canadian Industrial Energy End-Use Data and Analysis Centre, Vancouver BC

2004 – 2005
Assistant, Melting Mountains Awareness Program (David Suzuki Foundation / Alpine Club of Canada / Environment Canada), Vancouver BC

2000 – 2001
Project Supervisor, Outland Reforestation, Toronto / Thunder Bay ON

Past Assignments

West Moberly First Nations: Impacts of a Suspension of the Site C Project on Construction Workers and Municipalities. Wrote expert testimony to inform the court with respect to an application for injunction with regards to how suspension of the project may affect current construction workers and municipalities in the region. (May 2018)

Indian and Northern Affairs Canada: Technical Review of Socio-economic Impact Assessment of the proposed Hope Bay Phase 2 Mine. Team lead of SNC Lavalin's technical review of socio-economic material in the final environmental impact statement of TMAC Resources' proposed Hope Bay Phase 2 mine in Nunavut. Review included reviewing regulatory and proponent documentation and advising INAC on appropriate responses. (Winter and Spring 2018)

BC Parks: Development of Living Labs climate change research framework. Developed a funding framework for climate change research in BC parks and protected areas. Work included developing a database of recent climate change research in BC Parks through literature review and survey, a database of potential research and funding partners, and facilitating sessions at a meeting with BC government staff. Oversaw two subcontractors in this work. (Fall 2017-Spring 2018)

BC MFLNRO: Socio-economic profiles and scenario development – Caribou Range Planning in NE BC. Subcontracted to Green Analytics. Developed scenarios of forestry and gas development, and provided strategic advice. (Spring 2018)

Alberta Environment and Parks: Advice on Improved Integration of Project-level Environmental Impact Assessment and Regional Cumulative Effects Management. Reviewed existing linkages between project-level EIA in the South Athabasca Oil Sands area with regional cumulative effects management, including through expert interviews. Provided recommendations to improve the contribution of project-level EIA to regional cumulative effects management. (Fall 2017 – Spring 2018)

Environmental Law and Policy Center (USA): Assessment of the need for the Enbridge Line 3 Replacement Program. Provided written and in-person expert testimony of the need for the Enbridge L3R project, including an assessment of supply and demand of oil transport capacity, costs to Minnesota, and economic benefits of the project. (Fall 2017)

Centremount Coal: Socio-economic lead for SNC Lavalin's environmental assessment of the proposed Bingay coal mine. Scoping, baseline, and impact assessment studies of potential social, economic, and community health effects of the proposed Bingay coal mine in south-east BC. (2016-2018)

Pacific Future Energy: Socio-economic lead for SNC Lavalin's environmental assessment of the proposed Pacific Future Energy green refinery. Scoping and baseline studies of potential social, economic, and community health effects of the proposed green refinery in north-west BC. Advising to proponent on Aboriginal engagement, and engagement with Kitselas First Nation representatives. (2016-2017)

Gitga'at First Nation: Environmental assessment advisor. Since 2013, on an as-needed basis, provided advice to the Gitga'at First Nation regarding EA applications and processes, generally pertaining to socio-economic topics. Assignments included critiquing proponent EA applications, preparing Information Request submissions to EA bodies, and examining issues in EA application content and methodology with proponent consultants. (2013-2017)

Ng Ariss Fong: Assessment of the economic impacts of the Nathan E. Stewart tug spill on the Heiltsuk First Nation. Supported First Nation's legal claim against shipping company by gathering quantitative data, interviewing community representatives and members regarding traditional and commercial harvests, and estimating monetary impact of spill on Heiltsuk harvests. (2016)

Stk'emlupsemc te Secwepemc First Nation: Economic Review of Ajax Mine. Critiqued environmental assessment application of the KGHM Ajax mine project in Kamloops, BC with respect to economic impacts and value of the project. Conducted a multiple-accounts cost-benefit analysis of the project. Identified potential additional mitigation measures. Testified to the Nation's environmental assessment review panel. (2016)

International Pacific Halibut Commission: Facilitation of Management Strategy Evaluation workshops and design of outreach strategy. Over 2015 and 2016 designed and facilitated meetings for Management Strategy Advisory Board in support of their management strategy evaluation (a collaborative analysis of optimal fishery management actions). Also supervised the development of an outreach strategy for the board. (2015-2016)

Hemmera / Yukon Energy: Stakeholder engagement, meeting facilitation, and options assessment pertaining to the mitigation of impacts of the Southern Lakes Storage Enhancement Concept. Designed and facilitated two rounds of engagement with stakeholders regarding their preferences for erosion mitigation, including small and large group meetings. Conducted options assessment with engineering team (NHC) and explored options collaboratively with stakeholders. (2015)

Tsawout First Nation, Upper Nicola Band, Living Oceans Society: Public Interest Evaluation of the Kinder Morgan Trans Mountain Expansion Project. Contributing editor. Deliverable included an evaluation of Kinder Morgan's economic impact assessment of their proposed Trans Mountain Expansion Project and a cost-benefit analysis of the project. (2015)

Instream Fisheries Research: Facilitation of Gates Creek Sockeye Workshop. Designed and facilitated workshop focused on bringing together the variety of scientists and Aboriginal knowledge-holders, finding research gaps, and identifying steps forward with respect to information gathering, collaboration, and support of management. (2015)

Gitga'at First Nation: Impact Assessment of Prince Rupert LNG Projects. Led a two-person team and was the lead analyst in screening-level analyses of potential socio-economic impacts of three LNG projects (Prince Rupert LNG, Aurora LNG, Pacific Northwest LNG) and a detailed economic impact assessment of the Kitimat LNG project. Examined issues including: economic opportunities including jobs and contracts, access to goods and services, housing, human resources in remote communities, social cohesion, commercial fishing, tourism, carbon offsets, and economic development. Also supervised the writing of a baseline data report to help proponents fill their data gaps. (2014)

Metlakatla First Nation: Assessment of potential impacts of LNG development. Led a six-person team including subcontractor, and was lead analyst, examining the potential impacts of the Pacific Northwest LNG, Prince Rupert LNG, Westcoast Connector LNG pipeline, and Prince Rupert Gas Transmission LNG pipeline projects). Identified seven valued components through document review, interviews, and community workshop. Topic matter covered the economic, health, heritage, and social pillars. Developed baselines and gathered data for proponents. Developed a spreadsheet-based database and model to examine cumulative effects. Assessed the effects of projects in the context of cumulative effects of other development and stresses. Conducted a final workshop with community representatives to validate draft results. Researched mitigation opportunities. Developed a plain language summary for client in addition to detailed report. (2013-2014)

Gitga'at First Nation: Assessment of the potential economic impacts of LNG Canada project. Led a three-person team, and was the lead analyst. Identified six economic valued components through document review and interviews. Developed baselines. Developed a spreadsheet-based database and model to examine cumulative effects. Assessed the effects of projects in the context of cumulative effects of other development and stresses. Researched mitigation opportunities. Conducted a workshop with community representatives to validate draft results. (2013-2014)

Canadian Oil Sands Innovation Alliance: Structuring and gathering thinking on innovations in oil sands mine reclamation. Worked with two other firms on a multiple component project that gathered knowledge across oil sands mining companies on how to reclaim watersheds and to identify research priorities. (2013)

BC Ministry of Forests, Lands, and Natural Resources Operations: Recommendations for a Provincial Trails Advisory Body. Led a two-person team researching alternative governance models across Canada for recreational trails advisory bodies. Used a structured approach to identify key desired design elements, alternative governance structures, evaluate alternative models, and make recommendations for the BC trails context. (2013)

Marine Planning Partnership: Socio-economic data and editing. Supported MaPP planning team by gathering data on socio-economics including commercial fisheries and sport fishing along the BC coast and editing relevant sections of MaPP plans. (2013)

Environment Canada: Guidance on the valuation of ecosystem services for use in environmental assessment decision-making. Reviewed literature to identify existing gaps in the practice of environmental valuation in the environmental assessment context. Advised on the design of an expert workshop used to gather guidance on key issues in environmental valuation. Facilitated major portions of the workshop. Wrote guidance for Environment Canada to improve their in-house economic valuations of environmental impacts. (2012-2013)

Port Metro Vancouver: Facilitation of Technical Advisory Group in Support of Pre-EA Work for Marine Terminal Expansion at Roberts Bank. Co-designed a multi-meeting, multi-month process to engage technical experts to gather advice for Port Metro Vancouver (PMV) and their consultants to improve their baseline studies and environmental assessment methods for the proposed Terminal 2 project. Facilitated meetings over Fall 2012 and Winter/Spring 2013 in support of process, and worked with PMV consultants to refine issues and enhance their ability to engage with the technical experts. Lead facilitator for the Coastal Geomorphology technical advisory group (one of four such groups convened as part of this contract). (2012-2013)

Gitga'at First Nation: Assessment of the potential economic impacts of the Enbridge Northern Gateway Project. Assessed the potential economic impacts of the Enbridge Northern Gateway pipeline and tanker project on the Gitga'at Nation and examined broader issues such as how to incorporate risk information into decision-making. Critiqued the proponent's application, established baseline data, conducted original impact assessment work, and wrote evidence that was submitted to the Joint Review Panel examining the project. Testified to the Panel in April 2013. (2011-2013)

BC Environmental Assessment Office: Refinement of Impact Assessment Methodology. Co-wrote discussion paper for the BC EAO making suggestions with respect to how the BC government might modify the existing environmental assessment process in order to strengthen the process, particularly with respect to cumulative effects assessment. This work involved identifying key outstanding issues, interviewing experts, and writing policy guidance. (2012)

Cumulative Environmental Management Association: Support for a structured decision-making process to identify solutions to linear footprint management issues in the oil sands. Developed objectives and measurement criteria, and led workshop discussion on these topics, for work on the linear footprint management plan for the Stony Mountain 800 Area south of Fort McMurray. The objective of this project was to identify recommendations for government to address multiple uses of the area, including SAGD, forestry, trapping, and recreation. (2012)

City of Merritt: Water planning and conservation. Researched water conservation tools in support of recommendations to the City of Merritt for their new water plan, including interviewing of water experts in municipalities across BC and ranking of water conservation tools used across BC. Analyzed the City of Merritt's water use data. (2011)

Department of Fisheries and Oceans: Facilitation of SARA consultations for species recovery. Developed consultation strategies with DFO and facilitated two evening open-house meetings and five day workshops for stakeholder consultations required under the Species at Risk Act for the Salish Sucker, Nooksack Dace, Cultus Pygmy Sculpin, and Rocky Mountain Ridged Mussel. (2010-2011)

Haida First Nation: Evaluation of environmental and economic impacts of proposed NaiKun offshore wind project. Provided a third-party review of BC, federal, and consultant environmental assessments of the project in terms of gaps in data and logic, identified potential significant impacts, and advised on financial viability of the project. (2011)

Tides Foundation: Benefits of Marine Planning: An Assessment of Economic and Environmental Values. Reviewed the social and economic context for marine development on the BC coast and examined the benefits of marine planning with respect to environmental protection, economic development, and social capital. This research was also published in the journal Environments. (2009)

Department of Fisheries and Oceans: Review of potential impacts of renewable ocean energy development in BC. Reviewed the potential social and economic impacts of renewable ocean energy development in BC. Examined the potential for renewable ocean energy development (tidal, wave, and wind) on the BC coast, reviewed current levels of development, reviewed the socio-economic context of the BC coast, and explored how such development might affect employment, existing industries (e.g., air travel, aquaculture, forestry, and marine navigation), energy supply in rural areas, recreation, rural demographics, traditional activities, and other values. (2008)

Coastal First Nations: Review of environmental and socio-economic impacts of port development and shipping on BC North Coast. Reviewed the potential impacts of port expansion and shipping (including tankers) on the BC North Coast. Characterized the significance of potential impacts and reviewed potential mitigation measures, including Impact Benefit Agreements. (2008)

David Suzuki Foundation: Toward a National Sustainable Development Strategy in Canada. Researched and contributing writer of an examination of the legal and policy framework for sustainability planning across jurisdictions in Europe, Japan, the US, and Canada. Identified components across jurisdictions that facilitate a jurisdiction's ability to plan for and achieve greater sustainability. Report proposed a draft federal law which in 2008 was adopted by Parliament (Federal Sustainable Development Act). (2007)

Natural Resources Canada: National Circumstances Affecting Canada's Greenhouse Gas Emissions. Contributed to a quantitative study of factors shaping Canada's GHG emission patterns. Conducted analysis of emission patterns and contributing factors to emissions of Canada's residential housing, transportation, and wood processing sectors. This research was also published in the Energy Journal. (2005)

National Round Table on the Environment and the Economy: Canada's Energy and Greenhouse Gas Context. Contributed to a study on the linkages between Canada's energy sources and economy, international comparisons, and policy options for reducing GHG emissions. (2005)

Coastal First Nations: Review of offshore oil and gas development in BC. Literature review of the legal, environmental and socio-economic issues of offshore oil and gas development in BC and evaluation of the relevant planning process. Highlighted issues relevant to strategic and project-level decision-making. (2004)

Peer-Reviewed Publications

Joseph, C., T. Gunton, and M. Rutherford. 2017. A Method for Evaluating Environmental Assessment Systems. *Journal of Environmental Assessment and Policy* 19(3): 33 pp.

Joseph, C., T. Zeeg, D. Angus, A. Usborne, and E. Mutrie. 2017. Use of Significance Thresholds to Integrate Cumulative Effects into Project-level Socio-economic Impact Assessment in Canada. *Environmental Impact Assessment Review* (67): 1-9.

Joseph, C., T. Gunton, and M. Rutherford. 2015. Good practices for effective environmental assessment. *Impact Assessment and Project Appraisal* 33(4): 238-254.

Joseph, C., and A. Krishnaswamy. 2010. Factors of resiliency for forest communities in transition in British Columbia. *BC Journal of Ecosystems and Management* 10(3): 127-144.

Gunton, T. and C. Joseph. 2010. Economic and Environmental Values in Marine Planning: A Case Study of Canada's West Coast. *Environments* 37(3): 111-127.

Joseph, C., T.I. Gunton, and J.C. Day. 2008. Implementation of resource management plans: Identifying keys to success. *Journal of Environmental Management* 88: 594-606.

Bataille, C., N. Rivers, P. Mau, C. Joseph, and J. Tu. 2007. How malleable are the greenhouse gas emission intensities of high-intensity nations? A quantitative analysis. *Energy Journal* 28(1): 145-169.

Expert Evidence

Enbridge Line 3 Replacement project. Written and in-person testimony to the Minnesota Public Utilities Commission. 2017.

Ajax Copper/Gold Mine. Written and in-person testimony to Stk'emlupsemc te Secwepemc Nation Review Panel. 2016.

Kinder Morgan Expansion Project. Written testimony to the National Energy Board. 2015.

Enbridge Northern Gateway Pipeline. Written and in-person testimony to National Energy Board. 2013.

Peer Review of Research

Environmental Management

Journal of Environmental Assessment Policy and Management

Select Other Professional Publications

Joseph, C., and T.I. Gunton. 2010. Net economic and environmental benefits of an oil sands mine. Proceedings of the 29th USAEE/IAEE North American Conference in Calgary, Alberta, Canada, October 14-16, 2010.

Joseph, C. 2010. The Tar Sands of Alberta: Exploring the Gigaproject Concept. Proceedings of the Prairie Summit geography conference, June 1-5, 2010, Regina, SK.

Joseph, C., and T. I. Gunton. 2009. Benefits of Marine Planning: An Assessment of Economic and Environmental Values. Marine Planning Research Report No. 4. Prepared for Tides Canada Foundation. Burnaby, BC: School of Resource and Environmental Management, Simon Fraser University. 34 pp.

Nyboer, J., and C. Joseph. 2006. Development of Energy Intensity Indicators for Canadian Industry 1990-2004. Prepared for Canadian Industry Program for Energy Conservation and Natural Resources Canada. Canadian Industrial Energy End-use Data and Analysis Centre, Simon Fraser University. 32pp.

Nyboer, J., C. Joseph, and P. Mau. 2006. Development of Greenhouse Gas Intensity Indicators for Canadian Industry, 1990 to 2004. Prepared for Environment Canada and Natural Resources Canada. Canadian Industrial End-Use Energy Data and Analysis Centre, Simon Fraser University. 584pp.

Nyboer, J., C. Joseph, N. Rivers, and P.Mau. 2006. A Review of Energy Consumption and Related Data Canadian Aluminium Industries 1990-2003. Prepared for Aluminium Industry Association. Canadian Industrial Energy End-use Data and Analysis Centre, Simon Fraser University. 36pp.

Nyboer, J., C. Joseph, N. Rivers, and P.Mau. 2006. A Review of Energy Consumption and Related Data Canadian Mining and Metal Smelting and Refining Industries 1990-2003. Prepared for Mining Association of Canada. Canadian Industrial Energy End-use Data and Analysis Centre, Simon Fraser University. 159pp.

Presentations, Guest Lectures, and Workshops

Lead workshop for environmental professionals entitled "Environmental Assessment in Canada: Current Issues and Prospects for Improvement" for Faculty of Environment, Simon Fraser University, October 26, 2017. Vancouver, BC.

Lead workshop entitled "Valued Components Masterclass" at Canadian Institute's Cumulative Effects conference, June 21, 2017. Calgary, AB.

Presentation at Canadian Institute's Cumulative Effects conference entitled "Improving Cumulative Effects Assessment in Project-Level Assessment", June 20, 2017. Calgary, AB.

Presentation to SNC Lavalin staff entitled "Megaprojects: Navigating Failures, Bias, Symbolism, and Other Interesting Stuff", April 19, 2017. Vancouver, BC.

Presentations at IAIA'17 entitled "Benefits Assessment in Western Canada: Case studies and Lessons", April 6, 2017, and "Significance Thresholds to Integrate CEA in Project-level EA", April 7, 2016. Montreal, QC.

Presentation to the Federal EA Review Panel, December 11, 2016, Vancouver, BC.

Guest lecture to undergraduate economics class on economic impact assessment and the public interest, Simon Fraser University, March 13, 2014, Burnaby, BC.

Public presentation for Moving Planets on Enbridge Northern Gateway project, March 27, 2012, Squamish, BC.

Guest lecture to undergraduate environmental studies class on megaproject review and the Enbridge Northern Gateway pipeline project at Quest University, March 15, 2012, Squamish, BC

Guest lecture to masters environmental assessment class on tar sands project review, School of Resource and Environmental Management, Simon Fraser University, February 28, 2011, Burnaby, BC.

Presentation at Unwrap the Research Conference entitled "The Tar Sands of Alberta: Exploring the Gigaproject Concept", October 24, 2010, Fort McMurray, AB.

Presentation at 29th USAEE/IAEE North American Conference entitled "Net economic and environmental benefits of an oil sands mine", October 16, 2010, Calgary, AB.

Presentation at Prairie Summit 2010 geography conference entitled "The Tar Sands of Alberta: Exploring the Gigaproject Concept", June 4, 2010, Regina, SK.

Guest lecture to ecological economics class on cost-benefit analysis of tar sands development at Quest University, April 26, 2010, Squamish, BC

Presentation at community meeting on the economic risks of the Garibaldi at Squamish ski and residential project proposal, April 12, 2010, Squamish, BC.

Guest lecture on environmental assessment of large-scale projects to Geography 319 "Environmental Impact Assessment" at March 17, 2010, University of British Columbia, Vancouver, BC.

Public presentation hosted by Squamish Climate Action Network on Alberta Tar Sands, May 25, 2009, Squamish, BC.

Guest lecture entitled "Energy: A Love and Hate Relationship" to students at Capilano College, September, 2008, North Vancouver, BC.

Presentation to Butterfield & Robinson travel group on oil sands development, August 20, 2008, Calgary, AB.

Panel presenter at Whistler Energy Forum on energy and sustainability, June 8, 2008, Whistler, BC.

Presentation for REM seminar series entitled "Can Cost-Benefit Analysis be Improved with Stakeholder Involvement?", Simon Fraser University, November 1, 2007, Burnaby, BC.

Presentation at Canadian Pollution Prevention Roundtable entitled "Pricing Oil Sands Pollution? Balancing Expert and Stakeholder Input", June 14, 2007, Winnipeg, MB.

Presentation at ISSRM 2006 Conference entitled "Implementing Resource Plans: Lessons from BC", June 5, 2006, Vancouver, BC.

Presentation at PIBC Conference as part of session entitled "Planning Implementation: Lessons from the Field", April 19-22, 2005, Vancouver, BC.

Invited Speaker at "Dialogue Café" on climate change, February, 2005, Whistler, BC.

Co-presenter for REM Seminar series entitled "Offshore Oil and Gas in BC", Simon Fraser University, February 28, 2005, Burnaby, BC.

Presentation at BC Land Summit 2004 as part of session entitled "BC's Crown Land Planning Process - Does it Work?", May 14, 2004, Vancouver, BC.

Presentation at CONFOR 2004 conference entitled "An assessment of the British Columbia strategic land use plan implementation framework and an identification of best practices for plan implementation", Dalhousie University, February 6, 2004, Halifax, NS.

Presentation for REM Seminar Series entitled "An Evaluation of the BC Strategic Land Use Planning Implementation Framework: Best Practices, Current Practices.", Simon Fraser University, November 14, 2003, Burnaby, BC.

Presentation at Annual Meeting of the Western Division of the Canadian Association of Geographers entitled "The Impact of Rock Climbing on the Soils and Vegetation at the Base of Cliffs.", Kwantlen University College, March 12-14, 1998, Richmond, BC.

Co-presenter at Annual Meeting of the Western Division of the Canadian Association of Geographers entitled "The Geomorphology of Small Push Moraines at Hilda Glacier, Banff National Park, Alberta", Kwantlen University College, March 12-14, 1998, Richmond, BC.

Awards

Sustainable Prosperity research grant, 2011

Waterhouse Graduate Fellowship in Organizational Change and Innovation, 2009

Jake McDonald Memorial Scholarship, 2007

Canada Graduate Scholarship – Doctoral (SSHRC), 2006-2009

2nd Place, Photography, Vancouver International Mountain Film Festival, 2003

Treeplanter of the Year, Outland Reforestation, 1996

Student Leadership, Ontario Secondary School Teachers' Federation, 1993

TAB 3

Jan Gorski, M.Sc., E.I.T.

Jan Gorski is an analyst at the Pembina Institute. He is a technical and policy analyst working with the fossil fuel team on a wide range of topics including methane policy, natural gas, oilsands development, and carbon pricing. Prior to Pembina, Jan worked in environmental consulting on atmospheric emissions in the oil and gas sector. He led numerous domestic and international field projects to measure emissions, conducted emissions inventories, developed new emissions measurement systems, and assessed new technologies to reduce emissions and other environmental impacts from upstream oil and gas. He has a Bachelor's degree in Aerospace Engineering and a Master's degree in Mechanical Engineering specializing in experimental combustion research.

EDUCATION M.Sc., Mechanical Engineering, Carleton University, 2012
B.Eng., Aerospace Engineering, Carleton University, 2008

EMPLOYMENT HISTORY

Pembina Institute, Analyst, Fossil Fuels (2018 – Present)
Clearstone Engineering Ltd., Intermediate Project Engineer (2014 – 2018)
Enclosures Direct Inc., Mechanical Designer (2013)
Carleton University/National Research Council Canada, Research Assistant (2009 – 2012)
University of Stuttgart, Research Intern (2011)
Carleton University, Research Assistant (2006)

LANGUAGES SPOKEN: English, Bosnian **LANGUAGES WRITTEN:** English, Bosnian

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REPRESENTATIVE EXPERIENCE

- Lifecycle emissions of cement production (2018).
- Research and consulting on the future of oil and gas in Canada (2018).
- Development and adoption of strong methane regulations across Canada (2018).
- Field coordination, technical analysis, and report preparation for the measurement of fugitive emissions from tailings ponds, mines, and other sources at Canadian oilsands facilities (2014 to 2018).
- Project lead for fugitive emissions survey of residential and commercial gas meters across Canada (2017).
- Assessment of technology to reduce the accumulation of fluid fine tailings from the oilsands (2017).
- Measurement of trace constituents in Canadian processed natural gas (2015 to 2017).
- Field demonstration of mobile emission measurement system at oil and gas facilities in China (2015).
- Development, testing, and validation of a mobile system to measure real-time atmospheric emissions from point, area, and volume sources (2015).
- Field measurement of GHG and CAC emissions from fired equipment in the upstream oil and gas industry (2014/2015).
- Development of a mobile lab for measuring stack gas emissions from combustion sources (2014/2015).
- Assessment of emissions reduction and control opportunities from flaring and fugitive emission at oil and gas facilities in India (2014).
- Identification of potential odour sources through the measurement of emissions from heavy oil storage tanks (2014).
- Procurement of equipment and development of procedures to conduct in-house calibrations of field equipment (2014 to 2018).
- Mechanical design for manufacture of custom electrical enclosures and automation of the design process (2013).
- Experimental research on the combustion dynamics of syngas and biogas flames including the design and construction of a combustion test facility at Carleton University (2009 to 2012).

RELEVANT PUBLICATIONS

- Jan Gorski, Wajid A. Chisty, Matthew R. Johnson (2014) Flame Response Analysis of Syngas, 1-8. In Proceedings of ASME Turbo Expo 2014 (Paper GT2014-25409).

TAB 4

PEMBINA institute

Teck Frontier Mine

Review of greenhouse gas emissions and climate change commitments

Version 1

Jan Gorski

Benjamin Israel

August 2018

About the Pembina Institute

The Pembina Institute is a national non-partisan think tank that advocates for strong, effective policies to support Canada's clean energy transition. We employ multi-faceted and highly collaborative approaches to change. Producing credible, evidence-based research and analysis, we consult directly with organizations to design and implement clean energy solutions, and convene diverse sets of stakeholders to identify and move toward common solutions.

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Teck Frontier Mine

Review of greenhouse gas emissions and climate change

Contents

List of Figures

List of Tables

Executive summary

When determining the climate impacts of oilsands projects, as a minimum, indirect upstream emissions from land use and the production of fuels used on site should be included. This is especially important when considering emissions in relation to provincial, national, and global GHG emission targets.

The Frontier project GHG emissions intensity is worse than both the CCIR benchmark for oilsands mining and other similar mining projects that use PFT technology. This is despite the fact that it will be the newest project by a margin of 8 years when it starts up in 2026.

The Teck Frontier project is at risk of pushing oilsands emissions past the 100 Mt cap due to its startup date occurring within the range of years when oilsands emissions are predicted to reach the cap. Teck has not made any allowance for the costs of compliance with the 100 Mt limit or the possibility of the suspension of the project due to the limit.

Teck has underestimated the cost of compliance with Alberta's Carbon Competitiveness Incentive Regulation by $2.5 billion.

This project's emissions are inconsistent with achieving Canada's 2030 and 2050 climate targets. To limit the global impacts of climate change there is an imperative for Canada to contribute to meeting its 2030 and 2050 climate targets.

The initial gap between Canada's projected emissions reductions and its 2030 target is significant. Regulatory uncertainty on the use of international offsets to meet those targets under the Paris Accord adds an additional unknown and only expands the emissions gap. Given this large gap, the approval of another significant source emissions is not consistent with Canada's climate goals.

For Canada's 2030 and 2050 targets to be met, emissions from the oilsands need to begin declining in the near future and not continue to rise as predicted by CERI.[1] Adding the Teck oilsands mine in 2026 with a 40-year lifetime is not consistent with achieving these goals.

[1] *Canadian Oil Sands Supply Costs and Development Projects,* 43.

1. Excluded project GHG emissions

The Teck Frontier Mine project represents a significant source of new greenhouse gas (GHG) emissions for Alberta and Canada. Teck's estimates that emissions for the Frontier oilsands mine project (direct plus indirect emissions from electricity use) are expected to total 11,183 t CO_2e/day,[2] translating into 4.1 Mt CO_2e per year. This represents 5.4% of total oilsands emissions based on 2016 data and 0.55% of Canada's 2016 total GHG emissions.[3] Teck's estimate of GHG emissions from the Frontier project, however, does not include all indirect emissions: missing are sources such as upstream emissions from the production of fuels used on site (natural gas and diesel being the most significant); emissions due to land use; and downstream emissions from refining and end use combustion.

The Pembina Institute has estimated that the indirect emissions from the extraction of natural gas and diesel, plus land use, total an additional 5,343 t CO_2e/day, or 48% of Teck's estimated total. In other words, should the Teck project proceed, it will be responsible for at least 48% more emissions than claimed in the application. Figure 1 shows the direct emissions, as well as indirect emissions from electricity use, fuel production, and land use GHG for the Teck Frontier project. This number does not include downstream emissions associated with refining and end use combustion, which would further significantly increase the total GHG emissions.

[2] Teck Resources Limited, *Frontier Oil Sands Mine Project Update* (June 2015), 14-9

[3] Based on National Inventory data from Environment and Climate Change Canada, *National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada, Part 3* (2018). https://unfccc.int/process-and-meetings/transparency-and-reporting/reporting-and-review-under-the-convention/greenhouse-gas-inventories-annex-i-parties/national-inventory-submissions-2018

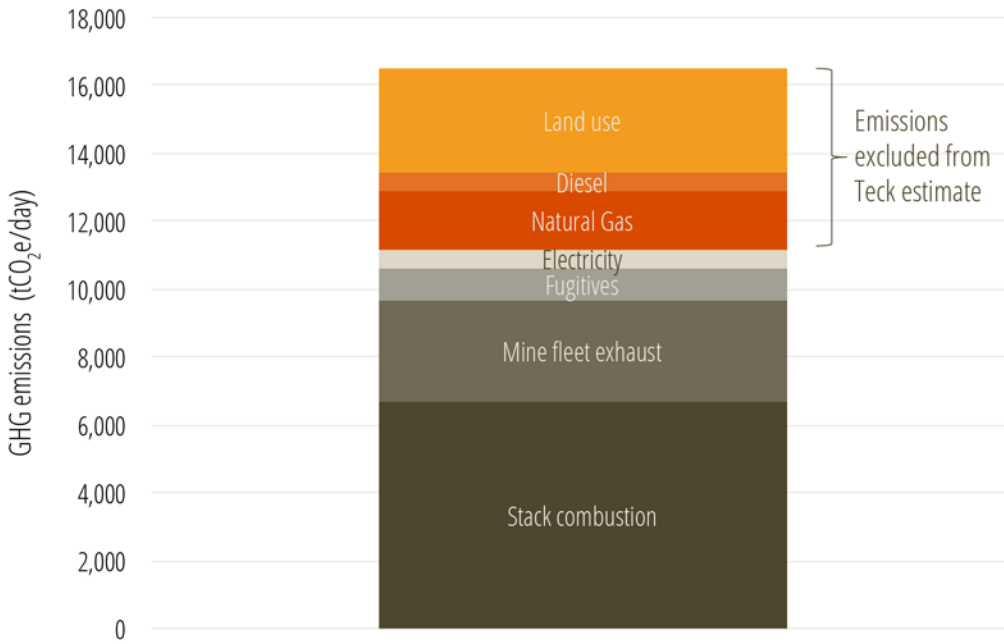

Figure 1. Teck Frontier direct and indirect upstream GHG emissions

Data sources: Teck, Pembina analysis (Appendix A)

All indirect emissions should be considered when determining the climate impacts of oilsands projects, especially in relation to provincial, national, and global GHG emission targets.

2. Comparison of GHG emissions intensities

While the absolute emissions (total per year) of a project are relevant to climate change, it is also useful to compare the emissions intensity of a project against other projects and benchmarks. Efforts to meet climate change commitments require significant reductions in emissions from all sectors. For example, in the oilsands industry, these reductions in absolute emissions can be achieved by limiting the total operating capacity (assuming intensity remains constant), by decreasing the emissions per barrel (assuming operating capacity remains constant), or by a combination of both.

Teck has estimated the GHG emission intensity for the Frontier project to be 38.4 kg CO_2e/bbl for direct emissions and 40.4 kg CO_2e/bbl when including both direct and indirect emissions.[4] As noted in Section 1 above, those estimates do not include GHG emissions from natural gas production, diesel production, land use changes, refining, or end use combustion. Teck has stated that the GHG emissions intensity of this project will be best in class.[5] In their information request responses, Teck has compared the Frontier project's emissions intensity against other similar projects and average oilsands mining and in situ projects.[6] This report provides a comparison against oilsands mining projects that use similar technology using more recent data and against benchmarks set out in Alberta's Carbon Competitiveness Incentive Regulation.

2.1 Comparison to similar technologies

Looking just at Teck's comparison against similar projects that use the new paraffinic froth treatment process — such as Imperial Oil Kearl, Suncor Fort Hills, and the CNRL Muskeg River/Jackpine mines (referred to here as the MRM complex) — reveals a wide range of GHG intensities and paints a picture of uncertainty in GHG emissions intensity.[7] A more critical look at the emissions from these operators using recent data allows a fair comparison to be made (see Table 1).

A detailed explanation of how these numbers were calculated is presented in Appendix A. To allow for a fair comparison, the Frontier and Kearl are compared using direct emissions only due to the lack of data on indirect emissions from the Kearl project, while Frontier, Fort Hills and the MRM Complex project are compared including indirect emissions from electricity. Despite being the newest project by a margin of 10 years, Frontier has the poorest emissions intensity of this

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[4] *Frontier Oil Sands Mine Project Update*, 14-9

[5] Response to JRP IR 3.15(a), 3-90.

[6] Response to JRP IR 3.15(e), 3-102 to 3-103.

[7] Response to JRP IR 3.15(e), 3-102 to 3-103.

group. As a result, while Teck indicates its intent to make the Frontier Mine project best-in-class with respect to GHG emissions intensity, it is in fact 24% more carbon intensive on a per-barrel basis than the best project.

Table 1. GHG emissions intensities from oilsands mining projects using paraffinic froth treatment

Project	GHG emissions intensity (kg CO_2e/bbl)	
	with indirect emissions (electricity use)	direct emissions only
Teck Frontier	40.4	38.4
Kearl	-	38.2
Fort Hills	33.2	-
MRM Complex	32.5	-

2.2 Comparison to benchmarks

In the context of the Carbon Competitiveness Incentive Regulation (CCIR), the Frontier Mine project's GHG emissions intensity is on par with the industry average for oilsands mining projects and not even close to best in class. The intensity benchmark from Alberta's CCIR regulation is 31.1 kg CO_2e/bbl as of 2018, compared to the Frontier project intensity of 40.4 kg CO_2e/bbl.[8] The benchmark includes indirect emissions associated with electricity, heat, and hydrogen.[9] It is based on the performance of the top quartile of bitumen mining operations on the basis of GHG emissions per barrel of bitumen produced. In the context of CCIR the Frontier project is not even top quartile. The CCIR regulation is designed to provide motivation for continuous improvement and so the intensity benchmark decreases year over year.[10] In 2026, when the Frontier mine is scheduled for startup, the CCIR limit for bitumen mining will have decreased to 28.9 kg CO_2e/bbl. The CCIR intensity limit includes indirect emissions, so the Teck project will have an intensity 40% higher than the CCIR threshold in 2026. A project with an emission intensity 40% higher than the sector benchmark does not qualify as 'best-in-class'.

According to analysis by the Pembina Institute, the average GHG emissions intensity of a barrel of bitumen produced from oilsands mining is 40.5 kg CO_2e/bbl in 2016.[11] This value is based on

[8] Government of Alberta, "Carbon Competitiveness Incentive Regulation," Alberta Regulation 96/2018, 51. http://www.qp.alberta.ca/1266.cfm?page=2017_255.cfm&leg_type=Regs&isbncln=9780779800193

[9] Government of Alberta, "Standard for Establishing and Assigning Benchmarks V2.1 Carbon Competitiveness Incentive Regulation," Updated June 2018, 25. https://www.alberta.ca/assets/documents/CCI-standard-establishing-assigning-benchmarks.pdf

[10] The CCIR begins to decrease by 0.0032 t CO_2e/bbl bitumen in 2020, which is approximately of the 1% 2020 benchmark.

[11] Data based on oilsands mining emissions reported by Environment and Climate Change Canada, *National Inventory Report 1990-2016, Part 3* and oilsands production data reported by Government of Alberta, "Total Oil Sands Production Graph," http://osip.alberta.ca/library/Dataset/Details/46

National Inventory Report data and includes indirect emissions from electricity but does not account for any imported or exported electricity. Based on this reference point, the Frontier project GHG emissions are on par with the average intensity in 2016.

Table 2 summarizes these benchmarks.

Table 2. GHG emissions intensities of Teck Frontier mine compared to CCIR benchmarks and oilsands mining average

Project/Benchmark	GHG emissions intensity (kg CO_2e/bbl)	Intensity includes
Teck Frontier	40.4	indirect emissions associated with electricity
CCIR mining benchmark 2018	31.1	indirect emissions associated with electricity, heat, and hydrogen
CCIR mining benchmark 2026	28.9	indirect emissions associated with electricity, heat, and hydrogen
Average oilsands mine	40.5	indirect emissions associated with electricity

3. Compliance risk for the 100 Mt oilsands emissions limit

The Government of Alberta announced a 100 Mt limit on GHG emissions from the oilsands as a part of its Climate Leadership Plan in 2015.[12] This policy serves as a cap to ensure that emissions from the oilsands do not continue to grow without bounds. While the policy was announced in 2015, it has not yet been enacted as a regulation. The 100 Mt limit does not encompass the full scope of oilsands emissions and has specific exemptions from the following sources:[13]

- The electricity portion of co-generation
- Primary oil production (including cold heavy oil production with sand)
- Upgrading capacity added after Dec 31, 2015[14]
- Enhanced recovery projects[15]
- Experimental schemes

Teck states that it believes that the Frontier Mine project's emissions will not push the industry past the 100 Mt cap and that the cap may not be reached at all depending on how the regulation is structured and how emitters respond.[16]

Other sources predict that the 100 Mt limit will be reached between 2024 and 2030, as summarized in Figure 2. Environment and Climate Change Canada predicts that the 100 Mt cap will be reached by 2030 and that the emissions from electricity cogeneration, extra upgrading capacity, and primary oilsands will contribute an additional 14 Mt CO_2e.[17] This doesn't include enhanced recovery projects and experimental schemes, which may further contribute to real oilsands emissions despite the fact that they are excluded from the 100 Mt cap. David Hughes predicts that the limit will be reached by 2024 based on NEB production forecasts.[18] The Canadian Energy Research Institute (CERI) predicts that the limit will be reached by 2030.[19] CERI states that the limit can be avoided if industry works to adopt technologies that will lower

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[12] Government of Alberta, "Capping oil sands emissions," August 15, 2018. https://www.alberta.ca/climate-oilsands-emissions.aspx

[13] Ministry of Environment and Parks, "Bill 25 Oil Sands Emissions Limit Act," 2016, 3, http://www.assembly.ab.ca/ISYS/LADDAR_files/docs/bills/bill/legislature_29/session_2/20160308_bill-025.pdf

[14] The proposed regulation for the limit on oilsands emissions includes a 10 Mt provision for future upgrading.

[15] Emissions from the enhanced recovery projects and experimental schemes have not been estimated by the Environment and Climate Change Canada. Email correspondence between Barry Saxifrage and ECCC, March 8, 2018.

[16] Response to JRP IR 3.15(f), 3-107.

[17] Email correspondence between Barry Saxifrage and ECCC, March 8, 2018.

[18] J. David Hughes, *Canada's Energy Outlook: Current realities and implications for a carbon-constrained future* (2018), 84. https://ccpabc2018.files.wordpress.com/2018/05/cmp_canadas-energy-outlook-2018_full.pdf

[19] Dinara Millington, *Canadian Oil Sands Supply Costs and Development Projects (2018-2038)* (CERI, 2018), 43. https://www.ceri.ca/assets/files/Study_170_Full_Report.pdf

GHG emissions from oilsands production, but these technologies require further research and development before they are ready for commercial use.[20] Analysis by the Pembina Institute predicts that the 100 Mt limit will be reached in 2025. This details of this analysis are presented in Appendix C.

[20] Experience Nduagu et al, Economic Potentials and Efficiencies of Oil Sands Operations: Processes and Technologies, (CERI, 2017), 77. https://www.ceri.ca/assets/files/Study_164_Full_Report.pdf

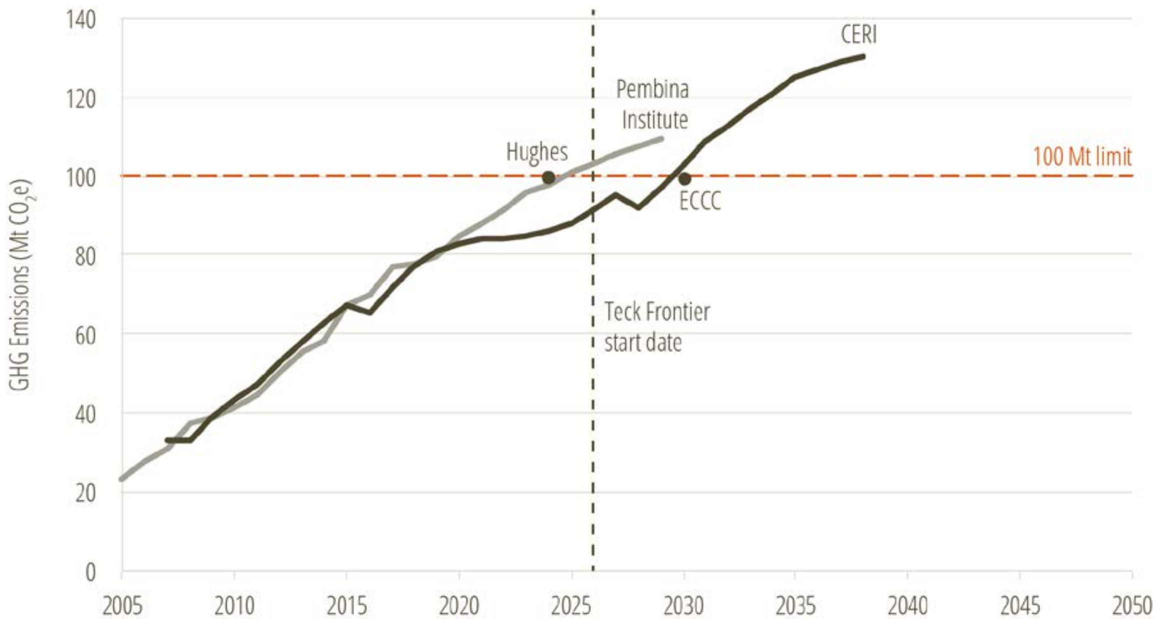

Figure 2. Oilsands GHG emissions forecasts

Data sources: CERI[21], Hughes[22], Pembina Institute, ECCC[23]

Based on the range of predictions shown in Figure 2, the Frontier Mine project is at risk of pushing oilsands emissions past the 100 Mt cap. While the actual structure for compliance with the 100 Mt cap remains unknown at this time, the Oil Sands Advisory Group (OSAG)[24] recommends that once the 100 Mt cap is reached, facilities in the worst two performing quartiles would be required to make emissions reductions. Facilities in the third quartile would be responsible for one-third of the reductions while facilities in the fourth quartile would be responsible for two-thirds of the reductions. OSAG also recommends that the Minister of Energy or Environment should have the authority to suspend project approval for facilities that have not yet started construction if the 100 Mt limit is approached. These actions would be determined based on 10-year forecasts. If a forecast indicates that oilsands emissions are expected to exceed the 100 Mt limit within five years, the actions stated above would be triggered.[25]

[21] *Canadian Oil Sands Supply Costs and Development Projects*, 43.

[22] *Canada's Energy Outlook.*

[23] Environment and Climate Change Canada, *Canada's 7th National Communication and 3rd Biennial Report* (2017), 153. https://www.canada.ca/content/dam/eccc/documents/pdf/cesindicators/progress-towards-canada-greenhouse-gas-reduction-target/Progress-towards-Canadas-GHG-emissions-target-en.pdf

[24] The Oil Sands Advisory Group (OSAG) was established by the Province of Alberta to advise the government on the parts of the Climate Leadership Plan that relate to oilsands. It is composed of representatives from industry, environmental organizations and Indigenous and non-Indigenous communities.

[25] Oil Sands Advisory Group, *Recommendations on Implementation of the Oil Sands Emissions Limit Established by the Alberta Climate Leadership Plan*, (May 8, 2017), 18. https://open.alberta.ca/publications/9781460134740

As discussed at Section 1 above, the Frontier Mine project's GHG emissions intensity is 40% higher than the CCIR benchmark in 2026. The worst-case scenario for Teck is that the 100 Mt limit is forecasted before construction starts and the project is suspended. If this does not occur, there is still a high risk that the project will fall into the worst two performing quartiles by the time startup occurs in 2026. This is a possibility given the analysis in Section 1 above which also shows that the emissions intensity of the project is on par with average oilsands mining intensities in 2016. If these emissions intensities improve at all during the next 10 years, Teck could face more stringent reduction targets. The Teck Frontier project is at risk of pushing oilsands emissions past the 100 Mt cap due to its startup date occurring within the range of years when oilsands emissions are predicted to reach the cap. Teck has not made any allowance for the costs of compliance with the 100 Mt limit or the possibility of the suspension of the project due to the limit.

4. Carbon Competitiveness Incentive Regulation compliance cost

Teck has calculated the cost of compliance with the former Specified Gas Emitters Regulation (SGER) at $635 million over the life of the Frontier Mine project. This cost greatly underestimates the cost of compliance with the current Carbon Competitiveness Incentive Regulation (CCIR).

Teck's calculation of cost under the SGER assumes a carbon credit price of $30/tonne. The Alberta Climate Leadership Plan anticipates the carbon fund credits rising to $50/tonne in 2022. This policy is backed by the Government of Canada's carbon pricing backstop which requires a price on carbon starting in 2018 and reaching $50 per tonne of CO_2e in 2022.[26]

OSEC has calculated the cost of compliance with the CCIR through the purchase of fund credits from the Government of Alberta at $1.9 billion over the life of the project with a carbon price of $30/tonne, and $3.1 billion with a carbon price of $50/tonne. The details of this analysis are shown in Appendix D.

[26] Environment and Climate Change Canada, *Technical Paper on Federal Carbon Pricing Backstop* (2017). https://www.canada.ca/content/dam/eccc/documents/pdf/20170518-2-en.pdf

5. Canada's climate targets

In 2015 Canada signed onto the Paris agreement, committing to a 30% reduction in GHG emissions from 2005 levels. Although the oilsands limit forms a firm stop for oilsands emissions growth, the Government of Canada's own projections show that both current and planned policies are likely to leave the country 66 Mt short of its Paris target.[27] This is despite the fact that the government's plan already relies on the purchase of 59 Mt of offsets from the Western Climate Initiative (WCI).[28] Excluding the emissions offsets, the government's climate plan will leave Canada less than halfway towards its 2030 targets.

Western Climate Initiative

The WCI is a cap-and-trade initiative created by a number of U.S. states, with several Canadian provinces having joined in recent years. Ontario has recently vowed to leave the initiative and scrap its cap-and-trade program, adding more uncertainty to the Canadian government's plan to purchase offsets as part its climate policies.

There are additional uncertainties regarding the availability of these offsets in the future. Under the Paris Accord, an agreement between Canada and the United States is necessary for the offsets to apply.[29] As it stands there is no such agreement and the rules regarding international offsets have yet to be written. Barry Saxifrage has stated that "Before any offsets can be used for Paris Accord accounting, a rulebook covering all the details for offsets must decided on… it is likely there will be Paris Accord intl offsets, but it is not certain yet. Until there is a detailed rulebook approved, no intl offsets can be used by anyone." The transfer of offsets would certainly not be possible if the United States pulls out of the Paris Accord, as they have stated they would.

The initial gap between Canada's projected emissions reductions and its 2030 target is significant. Regulatory uncertainty on the use of international offsets to meet those targets under the Paris Accord adds an additional unknown and only expands the emissions gap. Given this large gap, the approval of another significant source emissions is not consistent with Canada's climate goals.

[27] Environment and Climate Change Canada, *Canada's 7th National Communication and 3rd Biennial Report* (2017), 153. https://www.canada.ca/content/dam/eccc/documents/pdf/cesindicators/progress-towards-canada-greenhouse-gas-reduction-target/Progress-towards-Canadas-GHG-emissions-target-en.pdf

[28] Ibid.

[29] Barry Saxifrage, "Canada's climate gap twice as big as claimed - 59 million tonne carbon snafu," *Canada's National Observer*, March 27, 2018. https://www.nationalobserver.com/2018/03/27/analysis/canadas-climate-gap-twice-big-claimed-59-million-tonne-carbon-snafu

Looking further into the future, Canada's has set a mid-century GHG emissions target of 80% below 2005 levels.[30] The mid-century target is consistent with the Paris agreement goal of limiting the global temperature change to between 1.5 and 2°C. Figure 3 shows Canada's historical emissions, the Government of Canada's[31] future projections and climate targets, and expected growth in oilsands emissions based on CERI analysis.[32]

Meeting the mid-century target will require a large reduction in emissions from the oilsands sector. In 2016, Canada's GHG emissions reached 704 Mt of CO_2e, with 72 Mt coming from the oilsands. CERI predicts that oilsands emissions will continue to rise unless the industry takes specific measures to reduce them. Alberta's promised 100 Mt limit is a good start to limiting oilsands emissions, but Figure 3 shows that it is not ambitious enough to reach our 2050 goals. It is fundamentally unfair that the oilsands be allowed to grow and account for more than two-thirds of Canada's GHG emissions in 2050 while all other sectors of the economy decarbonize.

This project's emissions are inconsistent with achieving Canada's 2030 and 2050 climate targets. To limit the global impacts of climate change there is an imperative for Canada to contribute to meeting it's 2030 and 2050 climate targets. For Canada's 2030 and 2050 targets to be met, emissions from the oilsands need to begin declining in the near future and not continue to rise as predicted by CERI.[33] Adding the Teck oilsands mine in 2026 with a 40-year lifetime is not consistent with achieving these goals.

[30] Environment and Climate Change Canada, *Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy* (2016), 3.

[31] *Canada's 7th National Communication And 3rd Biennial Report*

[32] *Canadian Oil Sands Supply Costs and Development Projects,* 43.

[33] *Canadian Oil Sands Supply Costs and Development Projects,* 43.

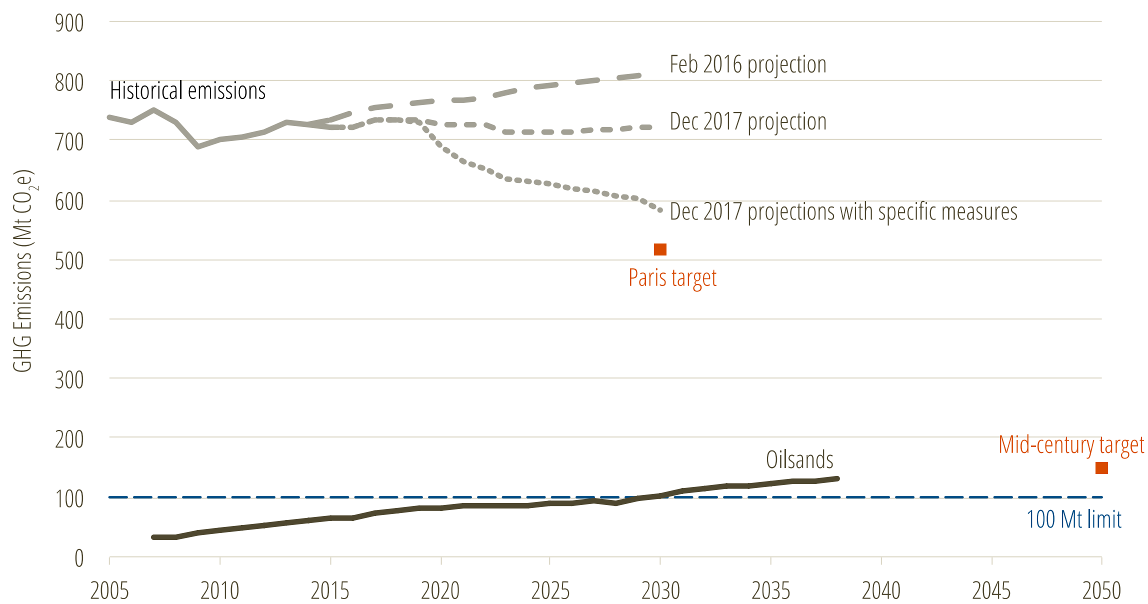

Figure 3. Canada's GHG emissions projections and targets

Appendix A. Excluded indirect emissions

Emissions from natural gas supply were calculated using the emission factor calculated in Appendix E and the natural gas use provided by Teck – 7021 GJ/hr.[34] With these values we get a GHG emission rate of 1697 t CO_2e/day.

Emissions from diesel supply were calculated using the diesel supply emission factor[35] of 18.5 g CO_2e/MJ and the diesel use provided by Teck – 1276 GJ/hr.[36] With these values we get a GHG emission rate of 568 t CO_2e/day.

Emissions from land use were calculated using the OPGEE model[37] and are based on emission factors presented in a study from 2010.[38] The total GHG emissions from land use for this project are estimated to be 3078 t CO_2e/day. These emissions are due to the release of soil and biomass carbon resulting from the complete removal of the soil and biomass from the mining site.

The total indirect GHG emissions that are unaccounted for are 5343 t CO_2e/day. The total direct and indirect emissions reported by Teck in their 2015 project update are 11,183 t CO_2e/day.[39] This means that Teck has underreported their total GHG emissions by 48%.

Table 3. Emission estimates from Teck Frontier Mine project

Emission source	Type of emission	GHG emissions (t CO_2e/day)
Stack combustion[a]	direct	6,696
Mine fleet exhaust[a]	direct	2,976
Fugitive emissions[a]	direct	957
Electricity[a]	indirect	555
Natural gas production[b]	indirect	1,697
Diesel production[b]	indirect	568
Land use[b]	indirect	3,078

[a] Source: Teck, *Frontier Oil Sands Mine Project Update*

[b] Calculated by Pembina Institute

[34] *Frontier Oil Sands Mine Project Update*, 11-6 and 11-7.

[35] GREET1_2016 model, as referenced in OPGEE_v2.0 "Fuel Cycle" sheet Table 2.5. https://eao.stanford.edu/research-areas/opgee

[36] *Frontier Oil Sands Mine Project Update*, 11-6 and 11-7.

[37] OPGEE_v2.0.

[38] Yeh et al, "Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands," *Environmental Science & Technology* 44 (2010).

[39] *Frontier Oil Sands Mine Project Update*, 14-9.

Appendix B. Oilsands emissions intensity of comparable projects

The results presented in Table 1 show the emissions intensities of oilsands mining projects that use the new paraffinic froth treatment technology and are comparable to the Teck Frontier project. To allow a conservative comparison, the Frontier and Kearl intensities do not include indirect emissions from electricity, while the Fort Hills and MRM Complex projects do (due to the lack of data on indirect emissions for Kearl). Despite being the newest project by a margin of 10 years, Frontier has the poorest emissions intensity of this group.

Kearl

Kearl is a relatively new facility and is still in the stages of optimizing their operation. The GHG emissions intensity from Kearl has been decreasing since 2013 and is at 38.2 kg CO_2e/bbl based on 2016 data.[40] These values do not include indirect emissions from electricity use on-site. However, the Kearl facility obtains its electricity from a natural gas cogeneration plant on-site, similar to what Teck is proposing.[41] It is fair to assume that the latest emissions intensity is the most representative of the long-term trend.

Table 4. GHG emissions intensity trends for Kearl project

Year	GHG Emissions Intensity (kg CO_2e/bbl)
2013	106.9
2014	47.7
2015	42.9
2016	38.2

Fort Hills

Teck's GHG emissions intensity data for the Suncor Fort Hills project is based on 2016 data. The latest Suncor climate report provides more up-to-date numbers.[42] The Suncor Fort Hills project is still in its first year of operation, but is forecasted to have a steady GHG emissions intensity of approximately 33 kg CO_2e/bbl from 2019 to 2022. These values include indirect emissions from electricity generation.

[40] Imperial Oil, *Kearl Oil Sands 2016 Annual Air Monitoring Report*, 2014 to 2017

[41] Imperial Oil, "Kearl." https://www.imperialoil.ca/en-ca/company/operations/oil-sands/kearl

[42] Suncor Energy Inc., *2018 Climate Risk and Resilience Report* (2018). https://sustainability.suncor.com/en/climate-change/ghg-performance.

Table 5. GHG emissions intensity trends for Fort Hills project[43]

Year	GHG Emissions (kt CO_2e/yr)	Production (bbl bitumen/yr)	Capacity Factor	Emissions Intensity (kg CO_2e/bbl)
2019	2187	63,729,000	0.900	34.3
2020	2211	66,065,730	0.933	33.5
2021	2087	68,402,460	0.966	30.5
2022	2354	70,810,000	1.000	33.2

MRM complex

For the Muskeg River and Jackpine mine complex (MRM complex), there is also a distinct trend of decreasing emissions intensity. The intensity increases in 2010 due to the startup of the Jackpine mine, but then continues to decrease, reaching 32.5 kg CO_2e/bbl based on Teck's analysis.[44] It is fair to assume that the latest emissions intensity is the most representative of the long term trend.

[43] Ibid, capacity factor estimated for 2020 and 2021 based on 2019 and 2022 forecasts.

[44] Response to JRP IR 3.15(e), p 3-102 to 3-103.

Appendix C. Oilsands production and GHG emissions forecasts, and analysis on 100 Mt limit

C.1 Modelling

Data source

The oilsands production forecast is derived from the Oil sands quarterly report made available by the Government of Alberta.[45] It uses the most recent spreadsheet published on the website (December 2017).[46]

The spreadsheet contains data for existing and planned oilsands projects, is structured along the following fields:

- OperatorName
- ProjectName
- PhaseName
- TechnologyDescription
- Status
- Capacity
- YearProductionStart

Methodology and assumptions

The first step consists in producing an oilsands production forecast. To do so, oilsands projects are grouped by technology type (i.e., “Mining,” “In situ,” or “Upgrading”) by assigning one type for each of the technologies described in the TechnologyDescription field.

A dynamic table is then created, which reads from the database and provides the production forecast with a breakdown per type (“Mining” and “In situ”) as well as per status (“Operating,” “In construction,” or “Approved”).

This analysis only considers oilsands extraction projects that are either existing or have a degree of certainty that they will proceed. Therefore upgrading projects are excluded from the analysis; only projects operating, in construction, and approved by the Regulator as of December 2017 are

[45] Government of Alberta, “Oil sands quarterly.” https://www.albertacanada.com/business/statistics/oil-sands-quarterly.aspx

[46] Government of Alberta, “Annual Oil Sands Project List Excel File - December 2017.” https://www.albertacanada.com/files/albertacanada/JWN-active-oilsands-projects-Dec-2017.xlsx

considered.[47] This also means that projects currently in the regulatory pipeline (such as Teck Frontier) are excluded from this analysis.[48]

Since oilsands projects do not typically run every day all year, an 85% capacity factor is used to forecast the oilsands production between now and 2030. The 85% capacity factor used in this analysis is slightly lower than the average for the last decade (85.8% between 2006 and 2016) and that of the past 16 years (87.8% between 2000 and 2016).[49]

The database does not contain a start-up year for all of the oilsands projects, and the YearProductionStart field reads “TBD” (or “To Be Determined”) for some of the facilities. The following assumptions were made to incorporate projects with uncertain start dates into the analysis:

- Operating projects with a “TBD” start-up year are excluded from the analysis (this only concerns a couple of marginal projects);
- There are no oilsands projects in construction with a “TBD” start-up year;
- It is assumed that only 50% of projects approved by the Regulator with a “TBD” start-up year will actually come online. It is assumed these projects will all be phased in at a 10% annual rate between 2020 and 2030.

All approved projects with a start-up year are assumed to start their operations at the year indicated in the database.

An emission forecast is then derived from predicted production using emission factors specific to the technology (mining or in situ), indicated in Table 6. These emission factors do not include indirect sources such as steam, electricity, or hydrogen which are also not included in the 100 Mt cap.

Table 6. Emissions factors used to forecast oilsands emissions

Oilsands technology	GHG Emissions Intensity (kg CO_2e/bbl)
Surface mining	67.9
In situ	75.2

Source: Government of Alberta[50]

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[47] Two manual modifications were done to the database: the status of Suncor Fort Hills project (Phase 1) was updated to operating as the facility started operations in January 2018, and the start-up year of the OSUM Oil Sands Corporation’s Orion Phase 2B project was updated from "TBD" to 2018.

[48] Projects with following status are excluded from the analysis: “Announced,” “Application,” “Disclosed,” “On hold,” “Suspended,” “Terminated”

[49] Oilsands capacity factors were calculated using existing production capacity sourced from Oilsands quarterly and production data sourced from Alberta Environment and Parks, Oil Sands Information Portal, “Total Oil Sands Production Graph”. http://osip.alberta.ca

[50] Government of Alberta, *Technical Guidance for Completing Specified Gas Compliance Reports,* Version 7.0 (January 2014,), 54. https://open.alberta.ca/dataset/1dac8a36-a586-4786-9f34-ef0cdcb13cfc/resource/58fbc932-c0dc-

Limitation and discussion

As any modelling work, this analysis contains some simplifications and limitations:

- This analysis assumes that only 50% of the approved projects that do not have a start-up year will proceed, which represents a conservative assumption given that these projects have already been approved by the regulator.
- Oilsands projects are assigned a broad technology type (“Mining” or “In situ”), and allocated the average emission factor of the dominant technology in this category. As a result, emission factors used in this analysis do not reflect the variety of techniques being used to produce bitumen.
    - Steam assisted gravity drainage (SAGD), for example, accounts for 80% of the in situ capacity operating in 2017, with cyclic steam stimulation (CSS) technologies making 19% of the capacity, and a mere 1% using other in situ techniques. The emission factor used to predict the emissions of in situ production is derived from the Specified Gas Emitter Regulation, which solely accounts for SAGD projects. CSS projects have been characterized in the literature as emitting tangibly more GHGs on a per-barrel basis than the median SAGD project.[51] Conversely, there are several pilot projects for co-injection techniques that inject a mix of steam and solvent, which have demonstrated emissions reductions on a per-barrel basis. These projects constitute 10% of all future production and their impact on the total emissions intensity is estimated to be immaterial to total emissions. In addition, these projects may qualify as experimental schemes, which are excluded from the 100 Mt limit.
    - The emission factor used for mining is derived from SGER historical data, which only considers mines equipped with an upgrader. As a result, the emission factor includes emissions for upgrading the bitumen. In our analysis it is applied to projects like Suncor Fort Hills and Imperial Oil Kearl that do not use upgraders, leading to an overestimate of mining’s emissions. A sensitivity analysis showed that the impact of this overestimate is small, and certainly within the margin of error of such analysis. In addition, the emission intensity of mining operations has historically increased and this trend is expected to continue for older operations as producers access deeper, lower-quality bitumen and the distance from mines to processing facilities increases.[52]
    - In addition, emission factors used in this analysis are constant and do not evolve over time. Although the Carbon Competitiveness Incentive Regulations create tangible incentives to improve the carbon performance of projects, the overall performance of

4c4c-8968-8bccafb61b89/download/zz-4904445-2014-01-technical-guidance-completing-specified-gas-compliance-version7.0.pdf

[51] A 2018 study indicates that CSS projects could lead to as much as 13% more GHG emissions per barrel than SAGD. Orellana et al, "Statistically Enhanced Model of In Situ Oil Sands Extraction Operations: An Evaluation of Variability in Greenhouse Gas Emissions," *Environmental Science & Technology* (2018) https://pubs.acs.org/doi/abs/10.1021/acs.est.7b04498

[52] Benjamin Israel, “The Real GHG trend: Oilsands among the most carbon intensive crudes in North America (2017),” *Pembina Institute*. http://www.pembina.org/blog/real-ghg-trend-oilsands

each technology is hard to predict as it is affected by conflicting forces. While marginal gains are expected through the implementation of technology improvements (e.g., co-injection of solvent and steam in in situ, automation in mining), these deployments cannot be economically and/or technically deployed on all projects. In addition, oilsands resources from high-quality reservoirs are typically developed first, resulting in a degradation of reservoir quality over time. Lower quality reservoirs will require more energy.

- This analysis does not consider projects in the regulatory pipeline as of December 2017, some of which will ultimately be approved and developed.
- All projects currently in operation are assumed to remain in operation until at least 2030.

While emissions trends are assumed to remain static in the future and the decrease in emissions intensity of new mines is not considered in the emission factors used, historically, emissions from oilsands mining have increased and only 50% of projects are assumed to proceed to operation. The analysis presented here is an approximation of when the 100 Mt cap will be achieved and believed to be balanced given the assumptions that have been made. Figure 2 presents the results of this analysis, including a comparison to the GHG emissions forecasted by CERI, which displays a similar profile.[53]

C.2 Detailed results

Table 7 and Table 8 present the forecasted GHG emissions from oilsands projects from 2016 to 2030 by project status and type respectively.

Table 7. GHG emission forecast from oilsands projects per status

Project status	GHG emissions (Mt CO_2e)														
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Operating projects	70.1	77.2	77.2	77.2	77.2	77.2	77.2	77.2	77.2	77.2	77.2	77.2	77.2	77.2	77.2
Projects in construction	0.0	0.0	0.6	1.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Projects approved with a start date	0.0	0.0	0.0	0.9	2.7	4.2	5.1	7.2	7.2	8.3	8.3	8.3	8.3	8.3	8.3
Projects approved without a start date	0.0	0.0	0.0	0.0	2.2	4.3	6.5	8.6	10.8	12.9	15.1	17.2	19.4	21.5	21.5
Total	**70.1**	**77.2**	**77.8**	**79.8**	**84.7**	**88.4**	**91.4**	**95.6**	**97.8**	**101.1**	**103.3**	**105.4**	**107.6**	**109.7**	**109.7**

[53] *Canadian Oil Sands Supply Costs and Development Projects*, 43.

Table 8. GHG emission forecast from oilsands projects per technology type

Technology type	GHG emissions (Mt CO_2e)														
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Mining	33.3	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
In situ	36.9	38.2	38.7	40.8	43.5	45.1	45.9	48.0	48.0	49.1	49.1	49.1	49.1	49.1	49.1
Projects TBD	0.0	0.0	0.0	0.0	2.2	4.3	6.5	8.6	10.8	12.9	15.1	17.2	19.4	21.5	21.5
Total	**70.1**	**77.2**	**77.8**	**79.8**	**84.7**	**88.4**	**91.4**	**95.6**	**97.8**	**101.1**	**103.3**	**105.4**	**107.6**	**109.7**	**109.7**

Appendix D. CCIR compliance costs

The costs of compliance with Alberta's CCIR regulations shown in Table 9 were calculated based project data from Teck. The allowed emissions are calculated based on the emissions intensity benchmark and annual production. The owed emissions are calculated by subtracting the allowed emissions from the project GHG emissions presented by Teck. Alberta's price on carbon is currently \$30/tonne CO_2e and will increase to \$50/t in 2020.[54]

Table 9. Frontier project cost of compliance with CCIR

Year[55]	Production (million m^3/yr)[56]	GHG emissions (Mt CO_2e)[57]	Emissions intensity benchmark (Mt CO_2e/m^3)[58]	Allowed emissions (Mt CO_2e)	Owed emissions (Mt CO_2e)	Compliance cost @ \$30/t (\$ million)	Compliance cost @ \$50/t (\$ million)
2026	9.86	2.50	0.1814	1.79	0.72	Exempt	Exempt
2027	9.86	2.50	0.1794	1.77	0.74	Exempt	Exempt
2028	9.86	2.50	0.1774	1.75	0.76	Exempt	Exempt
2029	9.86	2.50	0.1754	1.73	0.78	\$23	\$39
2030	9.86	2.50	0.1734	1.71	0.80	\$24	\$40
2031	9.86	2.50	0.1714	1.69	0.82	\$24	\$41
2032	9.86	2.50	0.1694	1.67	0.83	\$25	\$42
2033	9.86	2.50	0.1674	1.65	0.85	\$26	\$43
2034	9.86	2.50	0.1654	1.63	0.87	\$26	\$44

[54] Government of Alberta, "Climate Leadership Letter to Minister," 2015, https://www.alberta.ca/documents/climate/climate-leadership-report-to-minister.pdf

[55] Based on 41 year project lifetime stated by Teck Resources Limited, *Frontier Oil Sands Mine Project Update* 1-2.

[56] *Frontier Oil Sands Mine Project Update*, 4-3.

[57] Based on project GHG emissions intensity including direct and indirect emissions from Teck Resources Limited, *Frontier Oil Sands Mine Project Update*, 14-9

[58] Government of Alberta, "Carbon Competitiveness Incentive Regulation," Alberta Regulation 96/2018, p 51. http://www.qp.alberta.ca/1266.cfm?page=2017_255.cfm&leg_type=Regs&isbncln=9780779800193

Year[55]	Production (million m^3/yr)[56]	GHG emissions (Mt CO_2e)[57]	Emissions intensity benchmark (Mt CO_2e/m^3)[58]	Allowed emissions (Mt CO_2e)	Owed emissions (Mt CO_2e)	Compliance cost @ $30/t ($ million)	Compliance cost @ $50/t ($ million)
2035	9.86	2.50	0.1634	1.61	0.89	$27	$45
2036	9.86	2.50	0.1614	1.59	0.91	$27	$46
2037	15.07	3.83	0.1594	2.40	1.43	$43	$71
2038	15.07	3.83	0.1574	2.37	1.46	$44	$73
2039	15.07	3.83	0.1554	2.34	1.49	$45	$74
2040	15.07	3.83	0.1534	2.31	1.52	$46	$76
2041	15.07	3.83	0.1514	2.28	1.55	$46	$77
2042	15.07	3.83	0.1494	2.25	1.58	$47	$79
2043	15.07	3.83	0.1474	2.22	1.61	$48	$80
2044	15.07	3.83	0.1454	2.19	1.64	$49	$82
2045	15.07	3.83	0.1434	2.16	1.67	$50	$83
2046	15.07	3.83	0.1414	2.13	1.70	$51	$85
2047	15.07	3.83	0.1394	2.10	1.73	$52	$86
2048	15.07	3.83	0.1374	2.07	1.76	$53	$88
2049	15.07	3.83	0.1354	2.04	1.79	$54	$89
2050	15.07	3.83	0.1334	2.01	1.82	$55	$91
2051	15.07	3.83	0.1314	1.98	1.85	$55	$92
2052	15.07	3.83	0.1294	1.95	1.88	$56	$94
2053	15.07	3.83	0.1274	1.92	1.91	$57	$96
2054	15.07	3.83	0.1254	1.89	1.94	$58	$97
2055	15.07	3.83	0.1234	1.86	1.97	$59	$99
2056	15.07	3.83	0.1214	1.83	2.00	$60	$100
2057	15.07	3.83	0.1194	1.80	2.03	$61	$102
2058	15.07	3.83	0.1174	1.77	2.06	$62	$103

Year[55]	Production (million m^3/yr)[56]	GHG emissions (Mt CO_2e)[57]	Emissions intensity benchmark (Mt CO_2e/m^3)[58]	Allowed emissions (Mt CO_2e)	Owed emissions (Mt CO_2e)	Compliance cost @ $30/t ($ million)	Compliance cost @ $50/t ($ million)
2059	15.07	3.83	0.1154	1.74	2.09	$63	$105
2060	15.07	3.83	0.1134	1.71	2.12	$64	$106
2061	15.07	3.83	0.1114	1.68	2.15	$65	$108
2062	15.07	3.83	0.1094	1.65	2.18	$65	$109
2063	15.07	3.83	0.1074	1.62	2.21	$66	$111
2064	15.07	3.83	0.1054	1.59	2.24	$67	$112
2065	15.07	3.83	0.1034	1.56	2.27	$68	$114
2066	15.07	3.83	0.1014	1.53	2.30	$69	$115
Total						**$1,881**	**$3,135**

Appendix E. Natural gas production, processing, and transport emissions

Life cycle GHG emissions for natural gas in Canada were calculated using data from the 2018 National Inventory Report (NIR)[59] and are presented in Table 10. The results are based on 2016 data. Stationary combustion emissions for natural gas production and processing are obtained from Table A10-3. Fugitives, venting, flaring, and transport emissions are obtained from the 2018 CRF tables for 2016.[60] The total GHG emissions from natural gas production, processing, transmission, and distribution are 62.0 Mt CO_2e.

Table 10. Natural gas life cycle emissions

Source	CO_2 emissions (kt)	CH_4 emissions (kt)	CH_4 emissions (kt CO_2e)
Stationary combustion[a]	27,000.0	-	-
Transport	8,114.0	8.1	227.4
Fugitives			
a) Exploration	-	-	-
b) Production	2.6	92.8	2,597.3
c) Processing	7.7	10.9	305.8
d) Transmission and storage	38.6	46.9	1,314.3
e) Distribution	2.0	38.2	1,069.9
f) Other	55.7	286.5	8,022.3
Venting	3,857.8	299.4	8,382.6
Flaring	892.4	5.4	150.4
Total	**39,970.8**	**788.2**	**22,069.9**

[a]Stationary combustion emissions are presented as total GHG emissions and not separated into CO_2, CH_4, and N_2O.

The total marketable natural gas production in Canada was 158 billion m^3 in 2016.[61] This results in an upstream natural gas emission factor of 0.393 kg CO_2e/m^3 of natural gas. Converting this

[59] *National Inventory Report 1990-2016, Part 3.*

[60] Ibid.

[61] NEB, "Marketable Natural Gas Production in Canada, 2017," updated March 15, 2018. https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/stt/mrktblntrlgsprdctn-eng.html

value to units of energy using the high heating value for natural gas (reported as 39.03 MJ/m^3 for 2016[62]) we get an emission factor of 10.07 g CO_2e/MJ.

[62] Statistics Canada, "Report on Energy Supply and Demand in Canada, 2016 Preliminary," April 4, 2018, 130. https://www150.statcan.gc.ca/n1/en/catalogue/57-003-X

TAB 5

Jodi McNeill

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EDUCATION

2015 **MSc Environmental Change and Management** **University of Oxford**
Distinction
2014 Caryll Birkett Scholar of Trinity College

2013 **B.A.Hons Development Studies and Environmental Science** **McGill University**
First Class Honours and Dean's Honour List
2008 Recipient of the National Millennium Excellence Award

RELEVANT EMPLOYMENT HISTORY

03/2016 – Current **Technical and Policy Analyst**
The Pembina Institute — Calgary AB

07/2013 – 07/2014 **Environmental Scientist**
Ecoventure Inc. (Professional Environmental Consulting Firm) — Calgary AB

09/2012 – 12/2012 **Research Associate; Protected Agriculture Sector**
Inter-American Institute for Cooperation in Agriculture (IICA) — Barbados

RELEVANT PUBLICATIONS

McNeill, J. 2018. McNeill: Oilsands tailings ponds area nasty challenge that can't be ignored. *Calgary Herald*. April 29. Available at: https://calgaryherald.com/opinion/columnists/mcneill-oilsands-tailing-ponds-are-a-nasty-challenge-that-cant-be-ignored

McNeill, J., and Israel, B. 2018. Prospects for Alberta oil and gas in a decarbonizing world. *Prepared for the Government of Alberta Department of Energy's 2017 Energy Diversification Advisory Committee.* Available at: http://www.pembina.org/pub/prospects-for-alberta-oil-and-gas-a-decarbonizing-world

McNeill, J. 2017. The oilsands sector's toxic liquid legacy. *iPolitics*, [online]. November 7. Available at https://ipolitics.ca/2017/11/07/the-oilsands-sectors-toxic-liquid-legacy/

McNeill, J. 2017. Canadians need better protection from oilsands cleanup liabilities. *THIS Magazine*. July 24. Available at: https://this.org/2017/07/24/canadians-need-better-protection-from-oil-sands-cleanup-liabilities/

McNeill, J.L. and Thornton, T.F., 2017. Pipelines, Petitions, and Protests in the Internet Age: Exploring the Human Geographies of Online Petitions Challenging Proposed Transcontinental Alberta Oil Sands Pipelines. *Annals of the American Association of Geographers*, 107(6), pp.1279-1298.

WORKING GROUP PARTICIPATION

2016-Current Primary representative of Pembina Institute and ENGO caucus at the multi-stakeholder **Stakeholder Interest Group (SIG)** concerning the Tailings Management Framework (TMF) hosted by the Alberta Environment and Parks

2016-18 Primary representative of the Pembina Institute and the ENGO caucus at the multi-stakeholder **Integrated Water Management Working Group (IWMWG)** concerning the Tailings Management Framework (TMF) hosted by Alberta Environment and Parks

2016-18 Deputy representative of the Pembina Institute and ENGO caucus at the multi-stakeholder **Mine Financial Security Program - Tailings Management Framework (MFSP-TMF)** Working Group hosted by Alberta Environment and Parks

2017 Primary representative of Pembina Institute and ENGO caucus at the multi-stakeholder **Energy Diversification Advisory Committee (EDAC)** hosted by Alberta Energy

2016-17 Primary representative of the Pembina Institute and ENGO caucus at the multi-stakeholder **Technical Advisory Committee (TAC)** for Tailings Regulatory Management hosted by the Alberta Energy Regulator (AER)

REGULATORY SUBMISSIONS

2017-18 Representative of the Oilsands Environmental Coalition (OSEC) in multi-day formal Enhanced Review Processes for the tailings management plan submitted under Directive 085 for the Aurora North Mine and Millennium Mine and North Steepback Extension

2017-18 Co-author and signatory of OSEC's comprehensive review, technical analysis, and comments on the AER's draft conditions of approval for 7 tailings management plans

2016-17 Co-author and signatory of 7 statements of concern filed by OSEC on tailings management plans submitted by proponents under Directive 085. Submissions available at http://www.pembina.org/pub/statements-of-concern-on-tailings-ponds-solutions

RESEARCH AND FIELDWORK EXPERIENCE

2015 **Environmental Change Institute, Oxford University** • Published masters dissertation research focusing on contemporary public engagement with regulatory and policymaking processes for proposed transcontinental Alberta oilsands pipelines from 2005-15 • Novel quantitative and qualitative research methods designed to analyze geographies of scale

2013-14 **Ecoventure Inc.** • Environmental Impact Assessments and Environmental Screening Reports prepared for several proposed wildlife passages and stormwater culverts in three new west Edmonton neighborhoods • Research included desktop literature reviews, aboriginal consultations, and multiple in-field evaluations of wildlife corridors, wetland drainage patterns, and complex ravine systems

2013 **Ecoventure Inc.** • Phase I & II Environmental Site Assessments for upstream/midstream oil and gas operations in south Alberta • Required on-site soil sampling and analysis

2012 **Inter-American Institute for Cooperation in Agriculture (IICA)** • Interdisciplinary study of Environment, Water & Food Resources, and Sustainable Development at McGill's Bellairs Research Institute in Holetown, Barbados • IICA research assessment of the Barbados' Protected Agriculture (PA) sector • Findings compiled in an 80-page report and presented at a conference for PA stakeholders • Participated in design of a CAD$100,000 Canadian International Development Agency (CIDA) grant proposal

TAB 6

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EXPERIENCE

Mar 2018 – present The Pembina Institute Edmonton, AB
Director Fossil Fuels

- Coordinating our work on natural gas and oilsands. For example, convening progressive industry players, researching emerging low carbon technologies, analysing scenarios to meet Canada's emissions targets under the Paris Agreement, evaluating and commenting on regulations for reducing environmental impacts.

Sep 2016 – Dec 2017 The Pembina Institute Calgary/Edmonton, AB
Senior Analyst

- Led the oilsands tailings file, worked with industry, government, First Nations and Metis and other Environmental NGOs to analyse tailings management plans and advocate for better tailings management in the province.
- Coordinated the Pembina Institute's annual Climate Summit

Jun 2014 – Sep 2015 The Pembina Institute Calgary, AB
Senior Advisor

- Provided consulting services to industry clients. For example: reviewed and provided feedback on tailings management plans; convened international experts to comment on water management plans, researched and presented on carbon utilization technologies, summarized regulations for oilsand operations.

Jan 2013 – May 2013 Syncrude Canada Ltd Calgary, AB
Senior Project Manager

- Developed work scope and schedule for renewing regulatory approval for a new mine development.
- Hired and supervised sub-contractors to develop mine, tailings and closure plans for the new mine on time and on budget.
- Developed conceptual design for commodity connections between existing and new developments.

May 2012 – Jan 2013 Canada
Organic Farm Volunteer/Sustainable Lifestyles Internship

- Learnt about self-sufficiency, livestock, wool craft, soap making, food production and storage, community building, shelter, permaculture techniques by volunteering on 5 farms across Canada.

May 2011 – May 2012 Syncrude Canada Ltd Calgary, AB
Strategic Planning Advisor

- Identified 6 long term strategic issues facing the organization (Mine Development, Growth, Tailings, Reclamation, Water and Sulfur). 5 out of the 6 strategies endorsed by Syncrude Owners.
- Worked closely with Projects, Research, Planning, Legal, Regulatory and Public Affairs to complete a comprehensive analysis of options for each strategic issue.
- Facilitated internal organization alignment on the recommended path forward on each strategic issue and developed all presentation material

EXPERIENCE CONT.

- Due to the joint ownership of Syncrude, engaged with each of the owners throughout the development of options as well as final results in prep for Management Meeting.
- Supported commercial negotiations with neighbouring lease holders related to land use access, shared drilling, right of ways, boundary pillars etc.

Feb 2010 – May 2011 Syncrude Canada Ltd Calgary, AB
Team Leader - Project Estimating Services
- Managed a staff of 7 Syncrude employees and 4 contractor staff
- Team successfully completed and/or supervised the development by contractors of all capital project estimates for each stage of our capital project development process.
- Developed and stewarded to continuous improvement of the services provided to our internal clients.

Jan 2009 – Feb 2010 Syncrude Canada Ltd Calgary, AB
Project Development Engineer
- Developed technology and scope associated with a new tailings system, recycle water system, dredge and siphon. Overall project cost estimate during this phase >$300M
- Supported business case and cost estimate development. Managed and resolved key issues and risk logs. Provided engineering contractor oversight/quality assurance on recycle water system, dredge and siphon
- Liaison with Syncrude Operations, Tailings and Mine Planning and Execution groups

July 2007 – Sept 2008 Engineers Without Borders Ndola, Zambia
African Programs Staff
CARE International – Sorghum Marketing Enterprise Project
- Micro-enterprise development; Introduced small scale farmers to sorghum growing by providing training and free seed. Facilitated market links between farmer's cooperatives and the private sector (input and output markets)
- Influenced CARE to learn and improve project design and project implementation by initiating and carrying out monitoring and evaluation exercises during project implementation.
- Contributed to EWB's knowledge and understanding of rural realities, agriculture value chain projects and working within a large non-governmental organisation

Nov 2005 – June 2007 Syncrude Canada Ltd Fort McMurray, AB
Project Manager
- Managed haul road construction program. This work included developing scope of work, economic analysis, obtaining stakeholder approval, selecting and hiring contractors, ensuring safe, on time and on budget completion of the work. (Budget: $50M)
- Managed dewatering program for gravel resources.
- Managed mobile equipment acquisitions (dozers, graders, trucks, electric and hydraulic shovels). Included developing equipment needs, obtaining stakeholder approval, vendor selection and quality assurance during assembly or receipt. (Budget > $75M)
- Member of the Syncrude Graduate Development Project team. Review, re-design and implement a program that will train, develop and retain new graduate employees.

Nov 2002 – Nov 2005 Syncrude Canada Ltd Fort McMurray, AB
Engineer in Training
Mine Planning Department

EXPERIENCE CONT.

June 2002 - Oct 2002 Engineers Without Borders Ananea, Peru
International Cooperant
EWB & Centro Canadiense de Estudios y Cooperación Internacional (CECI-Peru)

- Studied the artisanal gold mining sector in Ananea, Department of Puno, Peru
- Completed a diagnostic of the mining methods and working conditions of 8 mining cooperatives in Ananea and their impact on local community.
- Wrote a proposal for a future CECI project in the area.

EDUCATION

1998-2002 McGill University Montreal, QC
Bachelor of Engineering (Mining), Minor in Management
McGill-Polytechnique Mining Engineering Coop Program.

1995–1997 Le Petit Séminaire du Québec Quebec, QC
International Baccalaureate in Applied Science

OTHER SKILLS/ACCOMPLISHMENTS

- The Natural Step's Sustainability Framework course, November 2013
- Corporate Social Responsibility course, University of Calgary Continuing Education, March 2013
- Completed course work and hours required for Project Management Professional designation

RELEVANT PUBLICATIONS

- Lothian, N., and McNeill, J. 2017. Tailings Management Plans; A review of Directive 085. Available at: http://www.pembina.org/pub/tailings-management-plans
- Lothian, N., 2017. Fifty years of oilsands equals only 0.1% of land reclaimed. *Oilsands at 50 series.* Available at: http://www.pembina.org/blog/fifty-years-of-oilsands-equals-only-0-1-of-land-reclaimed

WORKING GROUP PARTICIPATION

- Representative of the Pembina Institute at the multi-stakeholder **Mine Financial Security Program - Tailings Management Framework (MFSP-TMF)** Working Group hosted by Alberta Environment and Parks (2017)
- Representative of the Pembina Institute and ENGO caucus at the multi-stakeholder **Technical Advisory Committee (TAC)** for Tailings Regulatory Management hosted by the Alberta Energy Regulator (AER) (2015)
- Representative of the Pembina Institute at the multi-stakeholder **Tailings Management Framework (TMF)** workshops hosted by the Alberta Environment and Parks (2014)

- Representative of the Pembina Institute at the multi-stakeholder **Surface Water Quantity Management Framework working group (SWQMF)** hosted by the Alberta Environment and Parks (2014)

REGULATORY SUBMISSIONS

- Representative of the Oilsands Environmental Coalition (OSEC) in multi-day formal Enhanced Review Processes for the tailings management plan submitted under Directive 085 for the Aurora North Mine and Millennium Mine and North Steepback Extension (2017)
- Co-author of OSEC's comprehensive review, technical analysis, and comments on the AER's draft conditions of approval for 7 tailings management plans (2017 -2018)
- Co-author of 7 statements of concern filed by OSEC on tailings management plans submitted by proponents under Directive 085. Submissions available at (2016- 2017) http://www.pembina.org/pub/statements-of-concern-on-tailings-ponds-solutions

TAB 7

PEMBINA institute

Teck Frontier Mine

Review of liability management and financial security options

Jodi McNeill and Nina Lothian

August 2018

About the Pembina Institute

The Pembina Institute is a national non-partisan think tank that advocates for strong, effective policies to support Canada's clean energy transition. We employ multi-faceted and highly collaborative approaches to change. Producing credible, evidence-based research and analysis, we consult directly with organizations to design and implement clean energy solutions, and convene diverse sets of stakeholders to identify and move toward common solutions.

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Teck Frontier Mine

Review of liability management and financial security options

Contents

List of Figures

List of Tables

Executive summary

This report reviews the information pertaining to liability provided by Teck Resources Limited in the Environmental Assessment for the proposed Frontier Mine to determine if Teck's proposed liability management approach will sufficiently protect the public of Alberta from the risk of paying for the project's reclamation and closure costs.

Teck's proposed liability management approach is assessed, with three primary critiques for the Joint Review Panel to consider. First, evidence is provided that Teck's estimated timelines and costs for reclamation and closure are likely underestimated. Second, evidence is provided that Teck's emphasis on the company's diversification across multiple sectors and jurisdictions as a source of additional financial security is not a valid factor for the Joint Review Panel to consider in its review. Finally, concerns with the current design and structure of Alberta's Mine Financial Security Program relevant to the Frontier Mine are raised.

This report concludes with a recommendation that the elective option in the Mine Financial Security Program standard and the Appendix 4 Guide to the MFSP for operators to post full security be set as a binding condition of any forthcoming approval decisions to be issued on this project. This recommendation is put forth with four key caveats: (1) the payment schedule and management actions for non-compliance must be clearly delineated; (2) the security requirements must be binding upon sale or transfer or license; (3) the security requirements must be secured with a letter of credit or cash; and, (4) the estimated costs must be verified by a third-party audit. Each of these caveats is considered critical to ensuring the public of Alberta is adequately protected from the liability risk posed by the project.

1 Introduction

1.1 Context

Teck Resources Limited (Teck) has proposed to build the Frontier bitumen mine north of Fort McMurray, Alberta. Teck submitted an original environmental assessment application in 2011, and an updated environmental assessment application in 2015. A Joint Review Panel (JRP) comprised of the Alberta Energy Regulator (AER) and Canadian Environmental Assessment Agency (CEAA) thereafter issued eleven Information Requests.

The JRP is assessing the Teck Frontier Mine project under four laws: (1) Alberta's Environmental Protection and Enhancement Act; (2) Alberta's Responsible Energy Development Act; (3) Alberta's Oil Sands Conservation Act; and, (4) the Canadian Environmental Assessment Act.

As proposed by Teck, the Frontier Mine would have a nominal capacity of 260 thousand barrels per day. A first construction phase would occur from 2019 to 2026 with Phase I operations commencing in 2026, and a second construction phase would occur from 2030 to 2036, with Phase II operations commencing in 2037. The end of mine life (EML) would occur in 2066, followed by reclamation until 2081.

1.2 Scope of work

In the Environmental Assessment applications and supplemental submissions made to date, Teck has discussed anticipated liability posed by the Frontier Mine project and how it will be managed. This report reviews the information provided by Teck and provides an analysis of whether the public of Alberta will be sufficiently protected from the risk of paying for the project's reclamation and closure costs (i.e. liability).

The analysis is based on a review and critique of Teck's reclamation and closure plans and proposed approach to managing the liability that will be created by this project, as well as a review and critique of Alberta's Mine Financial Security Program (MFSP) more broadly as the principle mechanism under which liabilities in the oilsands mining sector are currently managed.

2 Critique of Teck's proposed liability management approach

2.1 Underestimated timelines and costs for reclamation and closure

2.1.1 Overview of Teck's reclamation and closure plans

In Section 13.4.1 of Volume 1 in the Project Update, Teck states that the updated Project Disturbance Area is 29,217 ha. Three pit lakes have been proposed to form integrated reclamation features within the closure landscape. They include: a North pit lake within the north pit; a Central pit lake within the main pit; and, a South pit lake within the main pit

These pit lakes will result in a 1879% increase in water bodies on the closure landscape relative to pre-disturbance. Other significant pre to post-development changes will include a 63% decrease in High Capability (Class 1) land, a 56% decrease in Moderate Capability (Class 2) land, a 411% increase in Low Capability (Class 3) land, a 63% decrease in Conditionally Productive (Class 4) land, and a 293% increase in Non-Productive (Class 5) land. These changes are illustrated by Table 13.6-4 in Volume 1 of the Project Update, included below as Figure 1.

Figure 1. Pre-and post- disturbance land capability changes

otal	**29,217**	**29,217**	**0**

Moreover, in Section 13.1 of Volume 1 in the Project Update, Teck delineates following timeline for reclamation activities:

(1) Initial reclamation to occur in 2024 (two years before production commences)
(2) Extensive reclamation starting in 2034 and continuing until 2067
(3) Pit lakes will begin to be filled in 2063, and filling will continue through 2080

(4) Pit lakes will be full of suitable water quality to begin discharging in 2081

Finally, in the company's response to question 5.4 in the Joint Review Panel (JRP)'s Information Request (IR) 5, Teck outlines reclamation and closure costs by phase. Total life of project liability is estimated to be $11.8 billion, with maximum liability occurring in 2037 at an estimated $4.3 billion when the fluid tailings[1] profile peaks, and liability at end of mine life expected to be roughly $2.9 billion. Teck provides a more detailed breakdown of costs in Table 5.4a-1, which is included as Figure 2 below.

Figure 2. Reclamation and closure cost details

Description	Construction ($million)	Operations ($million)	Closure ($million)	Total Project ($million)
Mine	**201**	**5,569**	**2,566**	**8,336**
Reclamation material salvage and placement	201	1,542	1,062	2,805
Centrifuged fluid tailings system	0	3,391	29	3,420
Tailings area re-contouring	0	400	0	400
Reclamation and closure – other	0	235	58	293
ETA seepage management system	0	0	482	482
Staff and fixed inputs and contract indirects	0	0	210	210
Closure drainage system	0	1	470	471
Water monitoring system	0	0	81	81
Pit lake filling system	0	0	174	174
Plant CFT operations and closure	**0**	**3,134**	**126**	**3,260**
Owner[1]	**0**	**0**	**228**	**228**
Total	**201**	**8,703**	**2,920**	**11,824**

NOTES:
ETA = external tailings area, CFT = centrifuged fine tailings.
[1]Owner's costs includes items such as salaries, insurance, contract administration.

2.1.2 Post-closure reclamation and monitoring uncertainties

Based on a review of Teck's proposed closure and reclamation plans, post-closure monitoring and/or mitigation requirements for the Frontier Mine project have very likely been meaningfully underestimated.

Table 1 illustrates various post-closure landscape features for which there is a high likelihood Teck has underestimated post-closure monitoring and/or mitigation requirements. Uncertainties are identified that raise the risk of higher costs and longer timelines for remediation, reclamation, and monitoring requirements after the anticipated EML in 2066 than have been accounted for.[2]

Table 1. Post-closure landscape features of concern

[1] According to the AER's Directive 085, fluid tailings are defined as "any fluid discard from bitumen extraction facilities containing more than 5 mass percent suspended solids and having less than an undrained shear strength of 5 kilopascals."

[2] This table includes *illustrative* examples of instances in which Teck suggests monitoring beyond 2081 may be necessary. It is not intended as a comprehensive list delineating all the uncertainties and risks posed by Teck's proposed reclamation and closure plans.

Post-closure landscape feature	Risk of underestimated costs and timelines for post-closure monitoring and/or mitigation requirements
1. End pit lakes	Section 13.6.4.5 in Volume 1 of the Project Update discusses plans for water release from the pit lake in 2081 when the water quality is expected to meet regulatory release criteria. If actual conditions differ from Teck’s models, however, several options are proposed to ensure pit lake water is suitable for discharge to receiving waters. These options include both natural bioremediation approaches and active treatment approaches. The passive treatment options include: (1) managing the rate of pit lake filling; (2) adding nutrients to the pit lakes to elevate productivity levels and biological treatment capacity; (3) increasing the efficiency and size of wetlands that route reclamation drainages to the pit lakes; and, (4) actively or passively treating pit lake outflows by adding wetlands and/or settling basins to the discharge channels that connect the pit lakes to the receiving waters. Active treatment options include adsorption, microfiltration, ultrafiltration, nanofiltration, reverse osmosis, and advanced oxidation. The impact of these additional interventions and monitoring requirements on reclamation timelines and costs is not addressed in Teck’s submissions to date.
	In Teck’s response to Question 2.6(c) in the JRP’s Information Request 2, a timeline for pit lake monitoring is provided. According to this timeline, pit lake filling will continue until 2080 followed by 30 years to establish an aquatic ecosystem, and 10 years of monitoring until 2121. This constitutes a minimum of 55 years after EML of reclamation and monitoring requirements, assuming no unforeseen circumstances arise that require additional management actions. Moreover, in response to Question 2.3 in the JRP’s Information Request 2, Teck acknowledges that while the timeline until 2121 is based on current analysis, “[it is] not possible to calculate or predict with certainty the timelines to establish ecosystems in reclamation waterbodies, such as pit lakes.” Despite these significant uncertainties, Teck has not provided details on the cost and management structures that will be in place until 2121, nor have details been provided on contingency plans to manage potentially extended timelines and/or additional costs.
	While every existing operator has proposed end pit lakes as part of the closure landscape, to date there has been no official regulatory review process to assess the cumulative impacts of the lakes on the regional landscape. The three end pit lakes that Teck has proposed will add to the dozens of lakes that other existing operators have proposed in their reclamation and closure plans. This lack of regional-level study is unacceptable, as the sum of oilsands mining operators reclamation and closure plans may not be ecologically or socio-economically viable at a regional scale. This gap in regulatory direction and oversight raises questions about Teck’s current closure landscape projections. As cumulative impacts are more comprehensively taken into account through future research and regulatory requirements, the features, costs and timelines in Teck’s current reclamation and closure plans could be impacted.
2. Centrifuged Fine Tailings Deposits	There are a number of uncertainties concerning Teck’s plans to terrestrially cap centrifuged fine tailings (CFT) deposits. According to Volume 1 of the Project Update and Teck’s response to the JRP’s Information Request 10, Teck anticipates a peak in the fluid tailings inventory of 242 Mm^3 in year 12 of operations. Teck plans to send coarse combined tailings (CCT), secondary flotation tailings (SFT) and froth treatment tailings (FTT) to external tailings areas (ETA) and an internal tailings area (ITA) for fines segregation (settling). The resulting fluid tailings will be removed, mixed with a polymer additive, and then sent to centrifuges to produce CFT cake.

	CFT cake will then be deposited in dedicated disposal areas (DDA). After four years of settling, Teck anticipates CCT, SFT, FTT, and FFT to consolidate into a solids content of 30%, with CFT cake of 55% solids concentration. Teck anticipates all FFT to be treated by centrifuging within 5 years of EML, and the DDAs to be terrestrial capped within 10 years of EML. However, there are significant uncertainties associated with reclaiming deep deposits of CFT cake. Teck has indicated that deep cake deposits will settle between 15 and 18-metres, with 8 to 10-metres of the settlement occurring after capping by 20 years post-placement, and the rest of the settlement occurring by 100 years post-placement. Indeed, Page 1-13 of Teck's response to Question the JRP's IR 1 states: "These assumptions are conservative, but in the unlikely event the current assumptions prove too optimistic and thick cake deposits are shown to consolidate and gain strength more slowly than assumed, then in-pit cake deposit and cap designs can be revised and adapted to achieve closure landscape sustainability objectives within a reasonable timeframe." Despite Teck's anticipated 100-year settlement timeline and the risk of slower-than-anticipated settlement and consolidation of the deposits, it is unclear how long monitoring will be required after the post-mining period ends in 2081, what corrective actions might be needed, how those actions might impact the final landscape, and what cost structures and contingency plans will be in place.
3. Seepage system	Section 14.11.3 in Volume 1 of the Project Update outlines the passive post-closure seepage collection system that will be placed around the north, east, and south perimeter of the ETAs. Teck plans to implement the system at the end of operations; during operations, groundwater seepage from the ETAs will be managed though perimeter ditching and a network of pumping wells in the quaternary sands. Teck states in Section 14.11.3.1 in Volume 1 of the Project Update that "[o]nce installed, the system will be monitored to verify that it is performing as intended;" however, it is unclear how long monitoring will take place. Teck further states "[s]hould conditions differ from what is expected, more intensive monitoring, intrusive investigations, and enhancement to the seepage control system will be completed as required to assess and address the situation." The impact of these additional monitoring and mitigation requirements on Teck's current estimates of post-closure reclamation timelines and costs is not addressed.
	Section 5.5.3.2 in Volume 3 of the Project Update discusses functioning of the post-closure seepage control system into the 'Far Future.' Teck states that seepage from the in-pit tailings deposits (WTDA and STDA) primarily occur to the local drainage system of the reclamation landscape, with discharge to the central and south pit lakes. However, small components of seepage are also anticipated along deeper flow paths to Big Creek, with travel times in the hundreds to thousands of years. While Teck assumes natural attenuation will render effects negligible, no analysis is provided of cumulative effects with seepage from other upstream tailings ponds and storage areas. Indeed, in Section 5.5 of this submission Teck only considers possible interaction with the Shell Pierre River Mine, which is on hold. Moreover, existing regulatory processes do not account for cumulative seepage impacts to the Athabasca River from other upstream operations of certain substances (i.e. naphthenic acid, polycyclic aromatic hydrocarbons). Increased analysis and regulatory oversight in the future could correspondingly impact monitoring and mitigation requirements along the Big Creek flow pathway.
	Section 13.122 in Volume 1 of the Project Update states that "the sustainability of the closure drainage system will be monitored through regular geomorphic surveys and site inspections following extreme precipitation or flood events" and "[s]ite

	inspections following extreme precipitation or flood events will assess whether uncontrolled erosion is occurring in the closure landscape." It is unclear how long after EML this monitoring will take place. Moreover, it is unclear what mitigation measures might be introduced if uncontrolled erosion is found to be occurring, and how such measures would impact reclamation costs and timelines.
4. Drainage system	Section 13.122 in Volume 1 of the Project Update states that "the sustainability of the closure drainage system will be monitored through regular geomorphic surveys and site inspections following extreme precipitation or flood events" and "[s]ite inspections following extreme precipitation or flood events will assess whether uncontrolled erosion is occurring in the closure landscape." It is unclear how long after EML this monitoring will take place. Moreover, it is unclear what mitigation measures might be introduced if uncontrolled erosion is found to be occurring, and how such measures would impact reclamation costs and timelines.
5. ETA drainage	Figures 13.6-17 to 13.6-22g in Volume 1 of the Project Update provide revised batch flush and solute transport modelling calculations as a set of time series plots for chloride and naphthenic acid. Based on figures 13.6-18 and 13.6-19, chloride concentrations will fully attenuate in drainage from ETAs in over 1500 years after EML in 2066, and naphthenic acid will fully attenuate in over 500 years. Moreover, according to Figure 13.6-19, chloride concentrations are anticipated to peak in 500 years after EML at Big Creek, 900 years after EML at Frontier FHCL, and 1200 years after EML in the Athabasca River. These centuries-long timelines raise concern regarding the potential need for perpetual management of chloride and naphthenic acid concentrations. This is particularly concerning regarding the manifold unknowns associated with naphthenic acid in oilsands process water, which are toxic to animals and aquatic creatures, and are weakly biodegradable leading to persistence in the environment.[3] Not only are current regulatory systems ill equipped to manage naphthenic acid, but identification and remediation poses significant and largely yet-unsolved scientific challenges.[4] These risks are further compounded by the lack of analysis concerning cumulative concentrations in the Athabasca River from other upstream operations over these extensive time periods in Teck's submissions to date. Moreover, policy and regulatory processes for managing these kinds of cumulative effects are broadly still under development, with input being provided from multi-stakeholder forums such as the Integrated Water Management Working Group for the Mineable Athabasca Oilsands.[5]
6. Surface water quality	Section 18.5.5.2 in Volume 1 of the Project Update discusses mitigation measures for surface water quality changes throughout the project's life, including construction, operation, and closure. Polishing ponds are proposed as a mitigation measure for the potential thermal effects of muskeg drainage and overburden dewatering and/or low dissolved oxygen levels prior to discharging into receiving waters. While this implies an active process of aeration, details are not provided regarding potential changes to reclamation timelines or costs.
	In Appendix 8.33 of Teck's response to JRP Information Request 8, information is

[3] Dalmia, A. (2013). Analysis of naphthenic acids in filtered oil sands process water (OSPW) using LC/TOF with no sample preparation. *Perkin Elmer*. http://www.perkinelmer.ca/lab-solutions/resources/docs/APP_Analysis_of_Nalphthenic_Acids.pdf

[4] Grewer DM et al. (2010). Naphthenic acids and other acid-extractables in water samples from Alberta: What is being measured? *Science of the Total Environment*. doi:10.1016/j.scitotenv.2010.08.013

[5] Alberta Environment and Parks. (2015). Call for delegates: Water Management Working Group. *Alberta Environment Network*. https://aenweb.ca/delegates/call-delegates-water-management-working-group-tailings-management-framework-mineable-athab

	provided pertaining to the Draft Hydrology and Water Quality Mitigation, Monitoring, and Adaptive Management Plan. Page 15 of this appendix shows surface water monitoring stations for the post-mining period (14 years prior to 2081 while the pit lakes are filled) and closure period (after 2081 when the pit lakes have been filled and begin to discharge). It is not clear based on the information provided how long the closure monitoring will continue, or what cost-management structures and contingency plans will be in place over this period that will ostensibly extend into the 22nd century.
7. Groundwater quality	Section 8.34 in Teck's response to the JRP's Information Request 8 discusses water quality in the south and east reclamation lakes as a proxy for the timeframe within which groundwater seepage concentrations might be above regulatory guidelines for drinking water. According to this section, the South pit lake will exceed drinking water standards for roughly 320 years for boron, and 600 years for sulphide. Teck also states in this Section that water quality in the south and east pit lakes will be used as a proxy for the timeframe within which groundwater seepage concentrations might be above regulatory guidelines for drinking water. Moreover, a 23-km long, 1.0-m thick, and 30–55-m deep hydraulic barrier wall has been proposed to passively control seepage. This system would cost \$200–500 million,[6] and will take 10–13 years to construct within the closure period of 2066-2081. Teck states that if groundwater monitoring results indicate that the hydraulic barrier is not performing as intended, seepage will be adaptively managed through modification of the design. While the company states this system may need to remain effective for 230 years, Teck does not appear to account for the costs of perpetual monitoring and potential design modification over that period. Finally, Teck states that the active pumping well network will continue to operate for as long as required to maintain acceptable water quality and flows in downgradient receptors if further assessment and design work determines that the passive hydraulic barrier is not technically and economically feasible. Teck does not appear to account for the costs of perpetually running the active pump and monitoring groundwater for the 230-year timeline that the hydraulic barrier may need to be in place.
	Teck's response to question 8.31 in the JRP's Information Request 8 states that concentrations of some substances will be above reference conditions and screening criteria for Ronald Lake, Redclay Creek and Big Creek. Teck also indicates exceedances of acute and chronic guidelines and Chronic Effect Benchmarks (CEBs) for some substances, and it appears that some predictions peak at the end of model predictions in 2081. This suggests monitoring and remediation actions may be necessary past the post-mining period and well into the closure period. Indeed, Teck's response to Question 8.31(b) references passive water treatment technologies being developed through COSIA that might be applied. However, no details are provided as to what these technologies are, what they might cost, the duration of time they will be required to function, the monitoring they would require, or contingency plans for unforeseen circumstances requiring active mitigation actions.
8. Soil pH	Teck's response to Question 107(b) in the AER's Supplementary Information Request 5 (April 2016) discusses pH blending in reclaimed soils. Low pH in the top 0–20-cm layer is expected to blend with high pH in the 20–50=cm layer, resulting in moderate pH levels. This process is expected to take three to five decades in conjunction with forest canopy establishment; should it not occur, final land capability classes for the

[6] Teck used the higher-end cost of \$500 million in its financial model for the project.

	landscape will be reduced. Teck does not provide management plans for this 50-year period, nor are contingency plans provided for how Teck will address poorer-than-anticipated blending results. This could result in longer timelines and higher costs for monitoring and/or mitigation actions.
9. Fish and fish habitat	Section 18.5.6.2 in Volume 1 of the Project Update discusses mitigation measures to manage changes to fish and fish habitat throughout the Project's life, including during construction, operation, and closure. In this section Teck states "[t]he project FHCL will be monitoring following construction to confirm that the habitat is functioning as intended" and "[a]dditional mitigation measures will be employed to reduce the effects on fish and fish habitat." The impact of these additional monitoring and requirements and interventions on reclamation timelines and costs is not addressed.

2.1.3 Risk of long-term public burden

Section 16.6 in Volume 1 of the Project Update states that '[t]he bulk of closure activity spending will take place in the first 10 years after the end of active mining and is expected to be complete when the pit lakes are integrated with the surrounding receiving waters in 2081."

However, as outlined above in Table 1, there are a multitude of uncertainties and risks in Teck's reclamation and closure plans that suggest costs and timelines have been meaningfully underestimated. Numerous policy and regulatory gaps in regional land-use planning and cumulative effects management from oilsands mining in the Northern Athabasca region compound these risks. Based on this analysis, there is a high likelihood that monitoring of deposit settlement, erosion, vegetation growth, and water quality beyond what is currently accounted for by Teck will be necessary for decades — or potentially centuries — after the reclamation period ends in 2081. While Teck has proposed an adaptive management approach wherein reclamation plans will be continually adjusted based on monitoring results, detailed contingency plans have not been provided delineating how Teck will manage changes to timelines and costs due to poorer-than-anticipated performance of various closure landscape features, real-world seepage patterns and cumulative substance concentrations that differ from modeled projections, and/or any other unforeseen circumstances.

These uncertainties pose a risk that perpetual monitoring and management at the post-closure site could be required at the expense of the public of Alberta in the long-term future. This risk pertains to enduring environmental, health, and social impacts on local communities, as well as fiscal impacts on future generations of Albertans more broadly.

2.1.4 Unique challenges of oilsands mine reclamation

In Teck's response to the Supplemental Information Request (SIR) 5 issued by the AER, the company repeatedly cites its experience with mining reclamation across a variety of assets. For instance, in response to question 152(b) Teck argues that reclamation is likely to be successful due to the company's recognized dedication to sustainability and experience in reclamation work.

This is also stated in response to question 153(a), where Teck emphasizes its extensive reclamation knowledge and experience.

While Teck's mining reclamation experience is valuable, it is imperative to note that reclamation in the oilsands mining sector poses numerous unique challenges relative to hard rock and coal mining operations.

Alberta's Conservation and Reclamation Regulation under the auspices of the Environmental Protection and Enhancement Act (EPEA) requires that oilsands operators must reclaim land disturbed by mines to "equivalent land capability." This is defined as "the ability of the land to support various land uses after conservation and reclamation is similar to the ability that existed prior to an activity being conducted on the land, but the individual land uses will not necessarily be identical."[7]

While the industry has long asserted that this reclamation objective shall be met, in the last fifty years of industrial-scale mining only 0.12% of land disturbed has been certified as reclaimed. The industry claims that 6.7% of land has been permanently reclaimed, but this land has not yet met regulatory requirements for certification.[8]

Moreover, to date no oilsands operator has successfully reclaimed fluid tailings. The only tailings pond to be reclaimed to date is Suncor Energy's (Suncor) Pond 1, from which all of the fluid tailings were removed. Suncor is currently making progress with reclaiming its Pond 5 that did contain fluid tailings; however, this has involved significant investment and innovation and has not yet been deemed successful.[9]

While most stakeholders — including the Pembina Institute — would contend that terrestrial capping of treated fluid tailings is a preferable alternative to water capping, significant unknowns remain with this approach. Indeed, several existing operators have proposed capping deep deposits of centrifuge cake in their Tailings Management Plans under *Directive 085: Fluid Tailings Management for Oilsands Mining Projects*. In the conditions of approval for these TMPs issued under the Alberta's Oil Sands Conservation Act (OSCA) and EPEA, the AER has required extensive research and reporting on capping plans due to the numerous unknowns associated with settlement patterns and long-term reclamation outcomes.[10]

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[7] Province of Alberta, Environmental Protection and Enhancement Act: Alberta Regulation 115/1993, 2 http://www.qp.alberta.ca/documents/Regs/1993_115.pdf

[8] Alberta Environment and Parks, Oil Sands Information Portal, "Regional Totals for Reclamation and Disturbance Tracking, by Year" (2016). http://osip.alberta.ca/library/Dataset/Details/27

[9] Wells et al. (2010). Suncor pond 5 coke cap – The story of its conception testing and advance to full scale construction. *Conference Paper*. http://www.barbau.ca/content/suncor-pond-5-coke-cap-story-its-conception-testing-and-advance-full-scale-construction

[10] See the AER's Directive 085 approvals for Suncor's Millennium Mine and North Steepback Extension, CNUL's Jackpine Mine and Muskeg River Mine, CNRL's Horizon Mine, Imperial's Kearl Mine, and Syncrude's Aurora North Mine. All operators are obliged by conditions of approval to develop research plans on terrestrial capping of fines dominated deposits.

Indeed, in response to Question 10.1 of Teck's response to the JRP's IR 10, total settlement in ITA1 of 15-17 metres is anticipated in a 50-metre deposit. Moreover, Teck's response to Question 6.11(a) of the JRP's Information Request 6 states that final reclamation of DDA1 occurs from 2073-2077, final reclamation of ITA 1 occurs from 2064-2075, and final reclamation of ITA 2 will occur from 2075-2080. Teck's response to Question 6.11(b) states that the landscape will be designed to accommodate an average settlement of 10 metres over DDA1, ITA1, and the two CFT cells. Teck then states that:

> "[s]ome differential settlement is expected, and would be beneficial in terms of providing more natural-looking terrain in the longer term, including the formation of opportunistic wetlands."

However, Teck does not provide detailed contingency plans regarding how these uncertainties in anticipated settlement patterns will be managed. This is concerning, as settlement ranging from 10–17 metres for these various deposits equates to a three- to five-story building. Settlement of this extent will significantly impact vegetation and landscape outcomes, and there is significant uncertainty over settlement rates and patterns that may alter monitoring and mitigation requirements for decades after the final reclamation period for these deposits.

2.2 Reliance on a "diversified" portfolio

2.2.1 Teck's experience and diversified assets

Teck's response to the JRP's Information Request 5 on socio-economic impacts of the project repeatedly emphasizes that the company's diversified portfolio renders the project lower risk for defaulting on clean-up obligations. Teck's portfolio includes: over 25 steelmaking/coking coal operations across several parts of British Columbia and Alberta, Canada; the Highland Valley Copper and molybdenum operation in south-central British Columbia, Canada; the Trail Operations zinc and lead smelting and refining complexes in southern British Columbia, Canada; the Antamina copper and zinc mine in Peru; the Quebrada Blanca copper mine and Carmen de Ancacollo copper and gold mine in Chile; the Pend Orielle zinc and lead mine in Washington State, U.S.A.; and, the Red Dog zinc mine in Alaska, U.S.A.[11]

In response to question 5.4(b) Teck emphasizes that the company has a "long history as a diversified resource company with experience managing reclamation liabilities relating to mining activities across multiple jurisdictions, including Alberta where, in addition to Teck's oil sands assets, Teck also has a steelmaking/coking coal operation (Cardinal River Operations)." Teck also states in response to question 5.4(d) that "[n]ot all operators have the demonstrated record of sustainability and responsibility that Teck has." Teck thereafter states that diversification across commodities and life-long assets in stable jurisdictions is a key management strategy, as it

[11] Teck, "Our Operations and Projects." https://www.teck.com/operations/

reduces exposure to any single commodity for which the price and long-term demand can fluctuate.

While Teck's track record for sustainable development in various other jurisdictions is appreciated, relying on the company's diversified portfolio as a means to ensure financial security for the Frontier project is concerning for two reasons. First, relying on other assets as a means to provide security through the Frontier mine's life raises concerns about the project's economic viability over the medium to long term; and secondly, this assertion would be invalid should Teck's other assets become insolvent and/or the Frontier project acquire new ownership following any forthcoming approvals. These issues will be further explored in the next sections.

2.2.2 Project viability

Question 5.4(b) in the JRP's Information Request 5 asked Teck to provide: (1) a comparison of project liabilities to securities provided by project through MFSP over course of project life; (2) an economic evaluation for the option to provide full security with reference to how much of project revenues will be set aside on annual basis for closure activities. The Oil Sands Environmental Coalition (OSEC) issued a similar request in Question 20 of its October 2016 submission regarding the sufficiency of information provided by Teck.

Rather than providing specific details including mine and reclamation schedules, assets, and liability calculations, Teck asserted in its response to the JRP's Information Request 5 that this information will be provided in accordance with timelines outlined in the Mine Financial Security Program standard and the Appendix 4 Guide to the MFSP (MFSP Guide).

Moreover, in the response to the JRP's Information Request 5, Teck made explicit assurances that other assets in the corporate portfolio could be utilized to provide security for the Frontier project; namely, pages 5-54 of Teck's submission states that "cash flows from Teck's portfolio of assets can be used to provide all or some of the security as opposed to only Project specific revenue."

Despite this assurance, Teck has not provided a comparison of closure liability to security over the full course of the project life including a schedule for posting security with specific sources of those funds (i.e. Frontier mine or other Teck assets). Interveners and the JRP therefore cannot transparently review the extent to which Teck plans to rely on its diversified portfolio to financially secure the liability of this project.

This information gap is highly relevant to the review of this project because, while it is reasonable to anticipate that Teck may need to use cash flows from its other assets to provide financial security for the Frontier mine at the project outset, the project itself must be able to provide security over its life. If this is not possible, it raises serious concerns as to the economic viability of the project. As discussed below, this is particularly relevant in relation to the risk of the rights to the Frontier mine being sold in part or in full to another operator any time over its life.

2.2.3 Conditional relevance of diversification

Teck's repeated assurances that revenue from its other corporate entities provide additional security for the Frontier project are only relevant assuming the following three conditions:

a. the other entities continue to operate in a profitable fashion;
b. revenues from other Teck corporate entities exceeds the reclamation liabilities of those entities; and,
c. rights to the Frontier project are not sold (in part or in full) any time.

None of these conditions can be assured with certainty under the purview of the Environmental Assessment for the Frontier project. Firstly, the JRP does not have access to information that would allow it to assess the financial health of Teck's operations across the multiple sectors and jurisdictions in which the company operates.

Secondly, Teck ostensibly has reclamation liabilities to manage at its other properties that fall under regulatory regimes that may or not manage liability in a responsible manner. For instance, in May 2016 the Auditor General of British Columbia found that provincial taxpayers were left responsible for least $508 million to identify and clean contaminated former mining sites on public land. The report also notes that British Columbia taxpayers are exposed to the risk of paying more than twice that amount in future costs, as there is a $1.2 billion shortfall in securities posted by mining companies under the current regulatory regime.[12] Teck is currently responsible for the largest proportion of that shortfall of any single mining operator, with only $500 million posted against total estimated reclamation costs of $1.187 billion in the province.[13]

Thirdly, the JRP cannot reliably predict Teck's current and/or future plans for mergers, acquisitions, and divestitures pertaining to the Frontier mine in its review of this project application. Critically, should the JRP issue an approval of this application, an additional Environmental Assessment would not be required if Teck were to sell the rights in part or in full to another operator that might not have the same degree of diversified and multi-jurisdictional holdings to offset the liability risk of the Frontier project.

For these reasons, is unreasonable for the other assets in Teck's corporate portfolio to be factored in to the Panel's review of the liability management approach and financial security options proposed for the Frontier mine.

[12] B.C. Auditor, *An Audit of Compliance and Enforcement of the Mining Sector* (2016). https://www.bcauditor.com/sites/default/files/publications/reports/OAGBC%20Mining%20Report%20FINAL.pdf

[13] Rob Shaw, "B.C. government's liability for contaminated sites balloons to $508 million," *Vancouver Sun*, June 30, 2016. https://vancouversun.com/news/politics/b-c-governments-liability-for-contaminated-sites-balloons-to-508-million

2.3 Inadequacies of the Mine Financial Security Program

2.3.1 Teck's preferred liability management approach

In the response to Question 5.4(b) in the JRP's Information Request 5, Teck states preference for a liability management approach wherein the current MFSP structure will be used. Teck outlines the following:

> "Where an approval holder (i) has MFSP assets at least three times greater than the MFSP liability, (ii) is 15 years or more from the end of its reserves, and (iii) is keeping current with its reclamation plans, additional security above the base security is not required. The base security for the Project (an oil sands mine without an upgrader) is $30 million. Based on Teck's economic assumptions and evaluation, Teck anticipates that posting additional security beyond the base security of $30 million will not be required until 2051, when the reserve life index falls below 15.00. Once the reserve life index falls below 15.00, Teck will post the additional Operating Life Deposit as identified in the MFSP throughout the remaining life of the mine."

Moreover, Teck's response to question 5.4(c) in the JRP's Information Request 5 emphasizes a "[commitment] to complying with MFSP" with the recognition in the future this might include requirements to post additional financial security under the Tailings Management Framework. Teck thereafter provides three options for additional security payments under the auspices of the MFSP.

While it is understandable that Teck would use the MFSP structure when designing its liability management approach in Alberta as the province's existing financial security program for the sector, the JRP must duly consider in its review of this application the July 2015 report by the province's Auditor General that deemed the MFSP program to be gravely inadequate in providing financial security in the oilsands mining sector.[14] As it exists today, the MFSP fundamentally misrepresents the liability risk to the Crown incurred by oilsands mines and improperly transfers significant public liability to future generations of Albertans. Sub-sections 2.3.2-2.3.4 of this submission will now outline these inadequacies.

2.3.2 Asset to liability approach is deeply flawed

Under the current structure of the MFSP, oilsands developers may offer undeveloped oilsands reserves as collateral for their liability costs. As a result, only about 3% of the $27 billion estimated by the AER in costs to reclaim existing oilsands mining sites is currently held in

[14] Auditor General of Alberta, *Report of the Auditor General of Alberta* (2015), 25. https://www.oag.ab.ca/webfiles/reports/OAG%20Report%20July%202015.pdf

securities by the province.[15] Moreover, there is a gross lack of transparency regarding the methodologies used to calculate the AER's $27 billion estimate, and it is therefore not possible for stakeholders to independently verify the assumptions that have been made regarding treatment technologies and closure outcomes for tailings ponds. As technologies to treat and reclaim fluid tailings to date have consistently resulted in higher costs and longer timelines than originally anticipated,[16] it stands to reason that the $27 billion estimate reflects a conservative estimate of the sector's liability.

Flaws in the current methodologies used to calculate assets and liability under the MFSP further compound the likelihood that the AER's $27 billion estimate is lower than actual liabilities in the oilsands mining sector.[17]

Firstly, the liability calculation methodologies under the MFSP are flawed, particularly in relation to capturing total costs to reclaim boreal wetlands and to treat and reclaim fluid tailings. The MFSP guide lacks detailed direction on what liabilities to include and how to factor in uncertainty, risk, and contingency. This is highly problematic as there are significant risks and uncertainties associated with how quickly and effectively various tailings treatment technologies will ensure progress towards self-sustaining landscapes. Indeed, no treatment technologies deployed to date have demonstrated long-term commercial success, and the reclamation of more complex substrates such as fluid tailings has not been achieved to date at a commercial scale.

Secondly, regarding the asset calculation methodology under the MFSP, the 2015 Auditor General's report states "the MFSP asset calculations do not incorporate a discount factor to reflect risk, use a forward price factor that underestimates the impact of future price declines, and treat proven and probable reserves as equally valuable." The Auditor General recommends that Alberta Environment and Parks "review the asset calculation to ensure it is not overestimating asset values [and] demonstrate that it has appropriately analyzed and concluded on the potential impacts of inappropriately extended mine life in the calculation."[18]

The need for the Auditor General's recommended review of the asset calculation under the MFSP is reinforced by provincial, federal and global commitments to curb the most dangerous impacts of climate change, which will directly impact carbon-intensive fuels. This increases the likelihood that the Alberta oilsands may not be developed as currently planned. If this occurs, the remaining

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[15] Alberta Energy Regulator, *Mine Financial Security Program – Security and Liability* (2017). https://www.aer.ca/documents/liability/MFSP_Liability.pdf

[16] Jodi McNeill, "Three strikes and you're out?" *Pembina Institute,* December 19, 2016 http://www.pembina.org/blog/three-strikes-and-you-re-out

[17] On August 15, 2017, the Pembina Institute, Alberta Wilderness Association, and Keepers of the Athabasca made a submission to the Tailings Management Framework – Mine Financial Security Program multi-stakeholder working group, held by the Government of Alberta. This submission discusses defects in the liability and asset calculation methodologies under the MFSP Guide.

[18] *Report of the Auditor General of Alberta* (2015), 25.

bitumen assets that are currently undeveloped will be worth far less than previous estimates.[19] As a result, using an asset-to-liability approach exposes the Crown to the potential liability of failed bitumen mine and processing plant operations. Despite industry's intentions to the contrary, there are many precedents for mining companies walking away from closure and reclamation responsibilities when asset values decline.[20]

It follows that the asset-to-liability approach of the MFSP exposes Alberta and Canadian taxpayers to considerable unfunded liabilities beyond those currently held in the program. As the Alberta Auditor General notes, "[b]ecause the MFSP has been designed using an asset-to-liability approach rather than a full security approach, Albertans bear a degree of risk that reclamation will not be completed by the mine operator."[21]

This is especially concerning in light of the inherent uncertainties associated with the long-term economic viability for oilsands mining in the 21st century. These uncertainties are a function of unknown future international oil prices, accelerating global transitions toward decarbonized energy systems, and the comparatively high start-up and operations costs of the oilsands mining industry.[22] If in the next several decades an existing operator is unable to complete extraction of their reserves for economic reasons, it is unlikely that the province or another operator will be able to do it viably either.

Moreover, the Redwater Energy Corp. (Redwater) legal case[23] has raised serious concerns about the extent to which taxpayers are protected from the economic and environmental liabilities incurred by Alberta's resource extraction industries.[24] Alberta-based Redwater declared bankruptcy in 2015, and the company's secured creditor and receiver argued that they should be permitted to use the profits of the company's assets to pay off loans while renouncing responsibility for the company's liabilities. When the AER brought the company to court over the matter, the Alberta Court of Queen's Bench ruled in favour of the creditors. On appeal, the Alberta Court of Appeal upheld the Court of Queen's Bench decision. The AER appealed the Court of Appeal decision to the Supreme Court of Canada. A decision from the Supreme Court of Canada is still pending. Should the Supreme Court of Canada uphold the Alberta Court of Appeal decision, it will confirm that receivers acting on behalf of defaulting companies are not legally

[19] Branko Bošković and Andrew Leach, *Leave It in the Ground? Incorporating the Social Cost of Carbon into Oil Sands Development* (2017), University of Alberta School of Business Research Paper No. 2920341. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2920341

[20] Canada's Ecofiscal Commission, *Responsible Risk: How putting a price on environmental risk makes disasters less likely* (2018). https://ecofiscal.ca/wp-content/uploads/2018/06/Ecofiscal-Commission-Risk-Pricing-Report-Responsible-Risk-July-11-2018.pdf

[21] *Report of the Auditor General of Alberta* (2015), 27.

[22] *Leave It in the Ground?*

[23] Court of Queen's Bench of Alberta, Redwater Energy Corporation (Re), 2016 ABQB 278. https://www.canlii.org/en/ab/abqb/doc/2016/2016abqb278/2016abqb278.html?resultIndex=1

[24] Jodi McNeill, "A liability iceberg in Alberta exposed by the Redwater case," *Pembina Institute,* April 26, 2018. http://www.pembina.org/blog/liability-iceberg-alberta-exposed-redwater-case

obligated to address outstanding liabilities of failed companies, but they are entitled to utilize outstanding assets.

This possible outcome of the Redwater case further compounds the fiscal and environmental risk posed to Alberta — and, likely Canadian — taxpayers of using the existing MFSP's asset-to-liability approach for financial security. Should oilsands mines become economically nonviable in the coming decades of the 21st century, insolvent operators and their bankers will be effectively incentivized to walk away from billions of dollars in clean-up obligations without penalty.

2.3.3 Failure of the MFSP to incent progressive reclamation

To date, very little progress has been made on reclamation of the landscape disturbed since oilsands mining at an industrial scale commenced in 1967. Of a total 95,302 ha disturbed, 6,339 ha is reported as permanently reclaimed and only 104 ha has been certified as reclaimed.[25] As the Auditor General states, "[i]f incentives are not in place to reclaim lands as soon as reclamation is possible, mine sites may remain disturbed for longer than necessary and Albertans face a larger risk that they will end up having to pay the eventual reclamation costs."[26]

Since its introduction in 2011 the MFSP has not meaningfully incented more timely and effective reclamation efforts in the sector. Under the current program, operators set their own targets for reclamation activities and tailings treatment, and if they don't meet those targets management actions may be imposed by the regulator. The current system thereby encourages operators to set less ambitious reclamation targets to avoid the risk of being in non-compliance.

[25] "Regional Totals for Reclamation and Disturbance Tracking, by Year."

[26] *Report of the Auditor General of Alberta* (2015), 27.

3 Recommendations

3.1 Full security option

Teck's response to Question 5.4(b) in the JRP's Information Request 5 provides project liability estimates. Teck estimates the total life-of-project liability to be $11.8 billion, maximum liability to peak at $4.3 billion, and liability at EML to be $2.9 billion.

In the maximum liability scenario, the highest liability for the project would be reached at the end of the year in 2037 when the fluid tailings inventory will reach 230 Mm^3 in ETA1. This volume will be processed at the centrifuge facility over seven years. If the mine should close in 2037, 54% of the Project Disturbed Area will be unreclaimed, with the total cost estimate under the MFSP of $4.3 billion.

Teck then states that under the current MFSP, if the company chooses or is required to provide full security, it would provide $4.3 billion. As per Section 5.1 of the MFSP Guide, the program provides an option whereby approval holders may elect to pay the full amount of financial security any time an MFSP annual report is submitted. With full financial security in place, the approval holder is not subject to MFSP deposits or triggers, and reporting requirements are reduced.

The Pembina Institute recommends that this full security option under Section 5.1 of the MFSP Guide be set as a condition of any forthcoming approval decision to be issued by the JRP for the Frontier Mine. However, this recommendation is put forth with four important caveats.

Caveat 1: Payment schedule and management actions for non-compliance must be delineated

Under the full security option in Section 5.1 of the MFSP guide, the approval holder for the Frontier Mine must be required to submit their financial security estimate to the director of the AER no later than June 30 each year using the appropriate form in the MFSP annual report (Schedule 3 of the MFSP Guide). The amount of financial security will be based on the MFSP liability calculations, and certified by the approval holder's designated financial representative.

As per Section 5.1.2 of the MFSP Guide, the approval holder of the Teck Frontier Mine may request return of all or part of the security posted when reclamation work is done that results in a significant decrease in MFSP liability. This includes facility demolition, remediation of an area, or surface reclamation of an area.

In alignment with the arguments made in 2.2.2 that the Teck Frontier Mine should be able to cover its own liability if it is an economically viable project, the security required will be equivalent to disturbance over time. This would equate to a smaller amount at the outset of operations and increase over time to the maximum of $4.3 billion in 2037, and decrease thereafter as reclamation activities are deemed successful. This would result in the phased return of deposits to the operator.

Finally, management actions for non-compliance must be clearly delineated should the operator of the Teck Frontier mine fail to post the required security at any point. This should include a range of options, ranging from financial penalties to forced project closure. Clear triggers should be delineated for these various management actions, to ensure stakeholders and the Alberta public can independently verify whether Teck is in compliance and, if not, whether the regulator is enforcing the decision.

Caveat 2: Must be binding upon sale or transfer of license

Any forthcoming conditions of approval must clearly state that the full security option under Section 5.1 of the MFSP Guide is *required* for the Frontier Mine, and that this requirement will be binding upon the sale of rights to the project to another operator at any time in the future.

Caveat 3: Must be secured with a letter of credit or cash

In its response to question 5.4(c) of the JRP's Information Request 5, Teck provides three options for posting additional security payments (in order of preference):

1. Secure against Project resource or other Alberta resource owned by Teck
2. Letter of credit
3. Cash

Option 1 must be omitted from consideration, as it is not a permitted form of security under Section 21 of the EPEA Conservation and Reclamation Regulation.

Per Section 4.6 of the MFSP Guide, Options 2 and 3 (letter of credit[27] or cash deposit) are both valid options for posting security.

Caveat 4: Costs must be verified by a third-party audit

According to the MFSP guide, liability is defined as "[t]he sum of the third-party (fair value) costs to suspend, abandon, remediate, and surface reclaim all the disturbed land associated with the approval." Furthermore, third-party costs are defined as "the costs to suspend, abandon, remediate, and surface reclaim a site that would be reasonably accessible by the Government of Alberta, or another third party, in the event of an unexpected default of the operation.

Pursuant to the concerns raised in Section 2.3.2 of this submission concerning lack of clarity and transparency in the MFSP Guide's calculation methodologies for both assets and liabilities, an audit of Teck's MFSP submissions is recommended to verify the estimates that have been provided prior to the commencement of operations. Per Section 7.4 of the MFSP Guide, a Level 4

[27] As defined on page 52 of the MGSP guide.

audit (i.e. a detailed audit by a third-party auditor reporting to the AER) is recommended prior to commencement of operations and every five years thereafter.

TAB 8

SIMON DYER

Telephone (587) 873 3937 • E-mail simond@pembina.org

RECENT WORK EXPERIENCE

December 2017 – present The Pembina Institute Edmonton, AB
Deputy Executive Director

- Delegated authority to act as Executive Director for all external and internal matters
- Responsibility for long range and annual strategic and business planning
- Co-chair of management and policy executive teams
- Research and analysis on oil sands and land use issues

January 2014 – December 2017 The Pembina Institute Edmonton, AB
Alberta Regional Director/Associate Director

- Strategic management and delivery of the Pembina Institute's Alberta program
- Budgeting, financial reporting, human resources and work planning for 20 staff and annual budget of $2.7 million
- Primary responsibility for government relations

January 2011 – December 2013 The Pembina Institute Calgary, AB
Policy Director

- Strategic management of the Pembina Institute policy program, comprising four policy divisions: oil sands, renewable energy and efficiency, climate policy and transportation
- Budgeting, financial reporting, human resources and work planning for 15 staff and annual budget of $2 million
- Research and analysis on public policy solutions for clean energy across Canada

January 2008 – December 2010 The Pembina Institute Calgary, AB
Oil Sands Program Director

- Strategic management of the Pembina Institute oil sands program
- Budgeting, human resources and work planning
- Manage bilateral negotiations with oil sands companies regarding developments, regulatory and legal interventions
- Participation in multi-stakeholder bodies such as the Cumulative Environmental Management Association (CEMA)
- Media spokesperson (>500 interviews per year)
- Research, analysis and writing on all environmental aspects of oil sands development including reclamation, conservation offsets, landuse planning and conservation, wetland policy development, woodland caribou management

January 2006 – December 2007 The Pembina Institute Calgary, AB
Senior Policy Analyst

- Research and analysis on all environmental aspects of oil sands development with a specific focus on land management challenges and solutions
- Bilateral negotiations with oil sands companies on terrestrial and wetland compensation, land management, water use and greenhouse gas reductions
- Participation in multi-stakeholder bodies such as the Cumulative Environmental Management Association (CEMA)
- Communication of impacts of oil sands development to public, media and decision-makers
- Member of expert witness panels – Suncor Voyageur Oil Sands Mine Hearing, and Imperial Kearl Oil Sands Mine Hearing

1999 - 2005 Alberta-Pacific Forest Industries Inc. Athabasca, AB
Wildlife Biologist, Forest Ecology Program Manager

- Research on impacts and mitigation of industrial activity on wildlife
- Forest Stewardship Council (FSC) certification lead
- Forest management plan author with focus on conservation, natural disturbance-based forestry practices and landscape planning
- Parks and protected areas planner supporting Al-Pac's contribution to regional conservation network

EDUCATION

1997 - 1999 University of Alberta Edmonton, AB
M.Sc. Environmental Biology and Ecology

1993 – 1996 University of Cambridge Cambridge, UK
M.A. (First Class Honours) Zoology with specialization in Ecology

ADDITIONAL TRAINING AND EXPERTISE

- Computer skills, including Microsoft Office suite and Arcview GIS
- Business planning, budget and contract management
- Familiarity with environmental impact assessment, natural resource management decision- making and principles of environmental management and protection
- Media Training
- Executive Leadership Training - Banff Centre
- Team Skills Training (6 modules)

MEMBERSHIPS, VOLUNTEER ACTIVITIES AND INTERESTS

- Board of Directors, Alberta Biodiversity Monitoring Institute 2007 – present (Vice-Chair)
- Alberta Society of Professional Biologists 2000 – present
- Bighorn Backcountry Standing Committee (Alberta Environment and Parks – provincial hiking representative) 2011 – present
- Board of Directors, Alberta Hiking Association 2010 - 2017
- Boreal Leadership Council 2008 - present
- U12, U10, U8 Assistant Soccer Coach, 2013 - present
- Enjoy hiking, hunting, camping, cross-country skiing and recreational soccer