Getting on Track

A primer on challenges to reducing carbon emissions in Canada's oilsands

Eyab Al-Aini | Chris Severson-Baker | Jan Gorski

March 2022

Photo: Kris Krüg, Flickr

Getting on Track

A primer on challenges to reducing carbon emissions in Canada's oilsands

Eyab Al-Aini

Chris Severson-Baker • Jan Gorski

March 2022

Contributors: Morrigan Simpson-Marran
Cover photo: Kris Krüg, Flickr

Recommended citation: Al-Aini, Eyab, Chris Severson-Baker, Jan Gorski. *Getting on Track: A primer on challenges to reducing carbon emissions in Canada's oilsands*. The Pembina Institute, 2022.
ISBN 1-897390-56-4

The Pembina Institute
219 19 Street NW
Calgary, AB
Canada T2N 2H9
Phone: 403-269-3344

Additional copies of this publication may be downloaded from the Pembina Institute website, www.pembina.org.

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 designing and implementing clean energy solutions, and convene diverse sets of stakeholders and decision-makers to identify and move toward common solutions.

pembina.org

twitter.com/pembina   facebook.com/pembina.institute

Donate to the Pembina Institute

Together, we can lead Canada's transition to clean energy. Your gift to the Pembina Institute directly supports environmental education and innovative research that advances understanding and action on critical energy and environmental issues.

pembina.org/donate

Acknowledgements

The Pembina Institute wishes to thank the third-party reviewers and experts who provided feedback and input for this report.

Thank you also to Ben Israël for laying the foundation with research and analysis that greatly informed this report as well to Morrigan Simpson Marran for her work on nature-based solutions.

Contents

List of Figures

List of Tables

Executive summary

Canada's oilsands producers face an unprecedented challenge. This carbon-intensive sector must respond in the short term to increasing pressure to eliminate its own greenhouse gas emissions, even as it confronts the prospect in the longer term of declining demand for its product. As a major employer and exporter, and important source of government revenues, the oilsands sector's performance on national and global decarbonization goals has serious ramifications that extend far beyond Alberta to every corner of Canada.

The oil and gas industry has been the fastest growing source of GHG emissions in Canada, accounting for 26% of the total in 2019, according to Environment and Climate Change Canada. Between 2005 and 2019, emissions from the oilsands soared by 137% as production increases outpaced a 12% reduction in per-barrel emissions intensity.[1]

Responding to pressure from investors, stakeholders, and governments, in June 2021 Canada's largest oilsands producers announced their own net-zero commitment in a joint initiative called the Oil Sands Pathways to Net Zero. The sector's emission reduction commitments — if met — would represent a significant contribution to delivery of Canada's climate strategy.

As this report notes, Canadian oilsands producers are not the first companies in the global oil sector to embrace a target of achieving net-zero emissions by 2050, nor are they likely to be the last. Although the specifics vary, Shell, BP and more recently, Exxon, have all adopted similar goals. These are important commitments that deserve careful scrutiny. The policy and technology pathways capable of leading to significant reductions in absolute emissions by 2030 and net-zero emissions by 2050 are complicated and need to be comprehensive. As more oil and gas companies attempt to determine their role in the transition to a net-zero economy, the promises they put forward warrant review by the full range of decision-makers and stakeholders on climate and energy issues. The purpose of this report is to help inform robust discussion and engagement on the pathways to net-zero that are — and can be — charted by leading Canadian oil and gas companies.

---

[1] Oilsands emissions intensity dropped from 91 to 80 kg CO_2e per barrel between 2005 and 2019 based on Environment and Climate Change Canada, *National Inventory Report 1990–2019: Greenhouse Gas Sources and Sinks in Canada* (2021) [*NIR-2021*], Figure 2- 25. https://publications.gc.ca/site/eng/9.506002/publication.html

Oilsands companies pledge to reduce absolute emissions

The Oil Sands Pathways to Net Zero initiative is an alliance of companies representing approximately 95% of oilsands production. Participating companies are the top six producers in Canada's oilsands — Suncor, Cenovus, Conoco Phillips, Canadian Natural Resources Ltd., Imperial Oil and MEG Energy. To achieve net-zero by 2050, they propose to deploy a combination of clean electrification, operational efficiencies, emerging technologies such as low-emission hydrogen and carbon capture, small modular nuclear, and offsets to eliminate 68 million tonnes (megatonnes: Mt) CO_2e from oilsands operations. Central to these activities is the point-source capture of CO_2 from oilsands upstream facilities, which would travel by pipeline from Fort McMurray to be used in enhanced oil recovery or sequestered permanently underground. The industry envisions a phased GHG reduction of upstream emissions over three 10-year segments to 2050, starting with 22 Mt CO_2e of absolute emission reductions by 2030.

The estimated cost of the proposed initiative is between $30 to $75 billion. The companies have asked the federal government to support up to 75% of the cost based on the argument that it will generate significant taxes, jobs, and other economic benefits. Released in June 2021 and developed during the pandemic when the price for oil was plummeting, the Oil Sands Pathways to Net-Zero vision pre-dated the soaring profits from rising crude oil prices, which has significantly enhanced the ability of Canada's oilsands sector to invest in its own decarbonization.

The industry has not yet published a plan that details how its net-zero vision could be achieved. The net-zero target put forward in the vision statement does not include GHGs from off-site processing or from end use refined combusted fuels, which together can account for 80% of life cycle emissions. It is also important to note that the companies have not yet proposed emission reductions that align with Canada's commitment to reduce total emissions by 40–45% from 2005 levels by 2030, or with Environment and Climate Change Canada's current assessment that at least 83 Mt CO_2e must be removed to achieve net-zero by 2050. Together with a commitment to build the required projects with limited public money, establishing credibility for a net-zero pathway for Canada's oilsands will require participating companies to produce a more detailed plan aligned with Canada's interim 2030 emissions reduction target.

In this report, we look at the challenge for oilsands producers to both decarbonize and remain competitive in a global market where the fight against climate change must result in demand for their product peaking in the coming decade and declining thereafter. In its net-zero 2050 scenario, the International Energy Agency (IEA) sees global demand for oil dropping to 24 million barrels per day in 2050, down from 98 million barrels per day in 2019. Even in a scenario in which the world fails to achieve net-zero by 2050, demand for crude is expected to decline in key markets like Canada, the United States and Europe, where the use of electric vehicles and other zero-emission transportation is growing rapidly.

The world is on a path that will see a decline in demand for oil

Today, the world is currently experiencing a spike in demand for oil precipitated by the rebound of activity following COVID shutdowns, supply chain disruption, and new geopolitical tensions. This is raising the possibility that along with the price of oil, gas, coal and other forms of energy, GHG emissions will increase during economic recovery from the pandemic and amidst new geopolitical conflict and uncertainty. However, notwithstanding current volatility in energy supply and demand, and uncertainty over how long it will last, countries representing 90% of global GDP and GHG emissions have committed to reduce the social, economic, and environmental impacts of climate change by collaborating to achieve net-zero emissions by 2050. Governments around the world are working to mitigate climate threats while providing access to secure and affordable clean energy, and investors are increasingly scrutinizing high-emissions industries and aligning their strategies with net-zero commitments. Given the reality of the need for this transition, and in order to avoid stranded assets, any pathway for emissions reduction in the Canadian oilsands sector should assume a reduction in both production and emissions as changing market fundamentals force Canadian oilsands producers to shutter their highest-cost operations.

In the short term, pledges made by banks and investors to pursue their own 2030 emissions reduction targets, and 2050 net-zero commitments, mean that oilsands producers will have to demonstrate significant progress in their emission reduction strategies to keep investment capital flowing into their sector.

Action to reduce oilsands absolute emissions must accelerate

To date, strategies for reducing emissions from Canada's oilsands have included fuel switching, operational efficiency, and targeted use of steam optimization and displacement methods. Since global prices retreated from their peak in 2008, and especially after the price collapse of 2014, oilsands companies have focused on cost reductions to remain competitive in a low price environment. Relative to conventional crude, the intensive use of natural gas and petroleum products required for oilsands production contributes to the high emissions profile of the sector, and so reducing that energy consumption will cut emissions as well as operating costs. Companies will continue to rely on operational changes to reduce emissions, and in many cases, reap competitive advantage and other benefits from continued cost savings.

While these strategies have resulted in significant progress in reducing both costs and emissions intensity, much larger investments are needed to reduce emissions at the scale necessary to align with the 40–45% reduction (from 2005 levels) required by 2030 in order to be consistent with a target of net-zero by 2050.

Policy is needed to hold companies accountable to net-zero commitments

In November of 2021, approximately five months after the Oil Sands Pathways to Net Zero initiative was published, the federal government announced that it will implement a cap on oil and gas emissions that will decline in line with Canada's net-zero goals. A cap on emissions represents a constant and predictable target. Done well, it can support investment decision-making and lower the risk of stranded assets. A cap on emissions from the Canadian oil and gas sector as a whole would also significantly increase opportunities for reductions between now and 2030 beyond the 22 Mt CO_2e envisioned in the oilsands pathways. This is because Canada has multiple low-cost emission reduction opportunities in the upstream oil and gas industry that are already technically and economically achievable.

As a regulated industry with significant point source emissions and available technologies for reducing emissions that have already proven to be viable at a commercial scale, Canada's oil and gas sector as a whole — of which the oilsands is a subsector — is better positioned than other parts of the Canadian economy to meet or exceed Canada's 2030 emissions reduction targets. Oil and gas projects outside of the oilsands have substantially lower marginal cost of abatement compared to oilsands projects. In contrast, the oilsands sector is better positioned to invest in more complex, multi-year large projects with higher marginal abatement costs that will become more viable as the cap on GHG emissions declines and carbon prices increase.

The 2021 vision statement by the Oil Sands Pathways identifies significant opportunities for decarbonization. While industry will need to overcome challenges and accelerate action to achieve this vision, they are well placed to do so. Profits reached a record high last year and are expected to increase this year due to higher oil prices. Canada also has a mix of policies that can drive this action if they are strengthened. To survive in a post-2030 world in which demand for oil will be declining, and competition between producers to deliver the lowest-cost and lowest-carbon barrel of oil will be intensifying, Canada's oilsands sector needs to make significant progress.

Several key assumptions in the Oil Sands Pathways to Net Zero vision require further rigour, scrutiny, and engagement between industry, decision-makers and stakeholders. In particular, the following four assumptions deserve more in-depth analysis and discussion.

1) Over the longer term, the oilsands industry anticipates that dramatic improvements in absolute emissions reductions will be achieved through the large-scale deployment of future technologies. These include wide-scale deployment of small modular nuclear reactors that provide power and heat, renewable electricity, and pure solvents to displace the steam currently generated from burning natural gas. However, many of these emerging technologies are yet to be commercialized. Due to long lead times in development and deployment, it is unlikely they will have a significant impact on oilsands emissions before 2030. Even in the longer term, some of these technologies face scale-up challenges that need to be overcome.

2) Much of the anticipated GHG reductions in the Oil Sands Pathways to Net Zero vision relies on carbon capture, utilization, and storage (CCUS). Identified as a critical technology in every IEA scenario for meeting global commitments to net-zero, CCUS adoption is not happening at the pace needed to achieve net-zero. Oilsands companies have an advantage, having been at the forefront of CCUS development in the last decade. The challenge for oilsands companies will be to design, get approved, and build the projects that their vision sees up and running by 2030.

3) The Oil Sands Pathways to Net Zero vision proposes to make significant use of nature-based offsets and negative emission technologies to compensate for hard-to-abate emissions as 2050 approaches. Many corporations are now investing in projects that sequester carbon in forests, soils, peatlands, and other carbon sinks. However, nature-based solutions come with their own challenges. Any investment must clearly generate emission reductions over and above what would have happened without it; and must be shown to be permanent despite threats from forest fires and other climate change impacts. Negative emissions — like direct air capture of CO_2 — are not the same as offsets as they are permanent, verified, and additional. Like CCUS, negative emissions technologies, including direct air capture of CO_2, have been identified by groups like the IEA and the UN Intergovernmental Panel on Climate Change as a critical technology for achieving net-zero. But, the challenges involved in getting this new technology and industry off the ground will limit its impact on emissions reduction between now and 2030.

4) Though not specifically referenced in the 2021 Oil Sands Pathways to Net Zero updates, oilsands companies also envision future uses of bitumen beyond combustion, such as creating carbon fibre. These uses present a long-term strategic economic opportunity compatible with lower oil demand scenarios. Upstream bitumen production would still need to be decarbonized to lower the life cycle emissions intensity of new high-value materials.

The Canadian Net-Zero Emissions Accountability Act, which came into force in June 2021, requires Ottawa to establish a clear path to net-zero emissions by 2050 based on five-year targets starting in 2030. It will be nearly impossible to establish such a pathway if Canada's oil and gas sector — its largest source of emissions — fails to align with the 2030 target of a 40–45% reduction over 2005 levels.

As the IEA has emphasized, in the long run — and notwithstanding shifts in energy demand and supply — the world cannot address climate change without significantly lower demand and production of crude oil. To manage the risk of stranded assets during this transition, any credible pathway for emissions reduction in Canada's oilsands needs to include the assumption that demand decline will translate into production decline.

In the short run, an emissions reduction strategy for oilsands that sees a 22 Mt CO_2e drop in emissions by 2030 — and assumes more substantial progress on emissions reduction will not occur for another decade or more — will not put oilsands producers on a credible pathway to meeting their own or Canada's net-zero target for 2050. Multiple pathways for emissions reduction will need to be pursued.

Along with other regulations and incentives, the emissions cap that is currently being pursued by the federal government should drive oilsands companies to achieve emission reduction opportunities that currently exist. It should also give oilsands companies access to compliance options that will accelerate technically and economically achievable GHG reductions in other parts of the oil and gas sector. This would put the sector on a path aligned with Canada's 2030 target.

The impending release by the federal government of a 2030 Emissions Reduction Plan for Canada represents a critical juncture for more rigorous review and collaboration among governments (federal, provincial, municipal, Indigenous) and with industry and stakeholders on the challenges and opportunities for emissions reduction in Canada's oilsands and oil and gas sector as a whole.

1. Introduction

1.1 Oilsands sector emissions and national climate commitments

In February 2020, the Pembina Institute published a report describing the impending disconnect between Canada's absolute oilsands sector emissions and national climate commitments.[2] The report identified the need for both additional climate ambition from oilsands companies and tangible plans to deliver such ambition, above and beyond incremental reductions in upstream production emissions intensity.[3] The international and Canadian contexts have dramatically shifted since that report was released. There is greater awareness of climate change globally, and an increasing recognition by national governments, investors, and the public of the need to quickly decarbonize to limit global warming to 1.5°C. Canada has announced the more ambitious target to reduce GHG emissions by 40–45% from 2005 levels by 2030. The federal government passed legislation laying out a pathway to reach net-zero by 2050, including a series of five-year targets starting in 2030.[4]

Oilsands emissions are already well beyond the 2005 baseline level. Between 2005 and 2019 in Canada, oil and gas had the largest growth in emissions of any sector, with an increase of 20%. This was largely driven by the oilsands, where absolute emissions increased by 137%.[5] Figure 1 shows that a 45% reduction of oilsands emissions from 2019 levels still results in absolute emissions in 2030 higher than 2005 emissions, Canada's baseline year. Environment and Climate Change Canada (ECCC)'s 2020 emissions projections showed oilsands emissions actually increasing to 95 Mt CO_2e by 2030,[6] which represents a 171% increase relative to 2005 levels.

---

[2] B. Israël et al, *The Oilsands in a Carbon-Constrained Canada: The collision course between overall emissions and national climate commitments* (Pembina Institute, 2020). https://www.pembina.org/pub/oilsands-carbon-constrained-canada

[3] In this report, emissions intensity, GHG intensity and carbon intensity are used interchangeably.

[4] In this report "net-zero" and "carbon neutral" are used interchangeably. All references to emissions in this report refer to greenhouse gas (GHG) emissions

[5] Over the same period, emissions decreased in three sectors, electricity (-48%), heavy industry (-12%), and waste (-10%), and increased in two sectors (transportation (16%) and buildings (8%). See section 2.1.2.

[6] Environment and Climate Change Canada, *Canada's Greenhouse Gas and Air Pollutant Emissions Projections 2020*. https://publications.gc.ca/site/eng/9.866115/publication.html

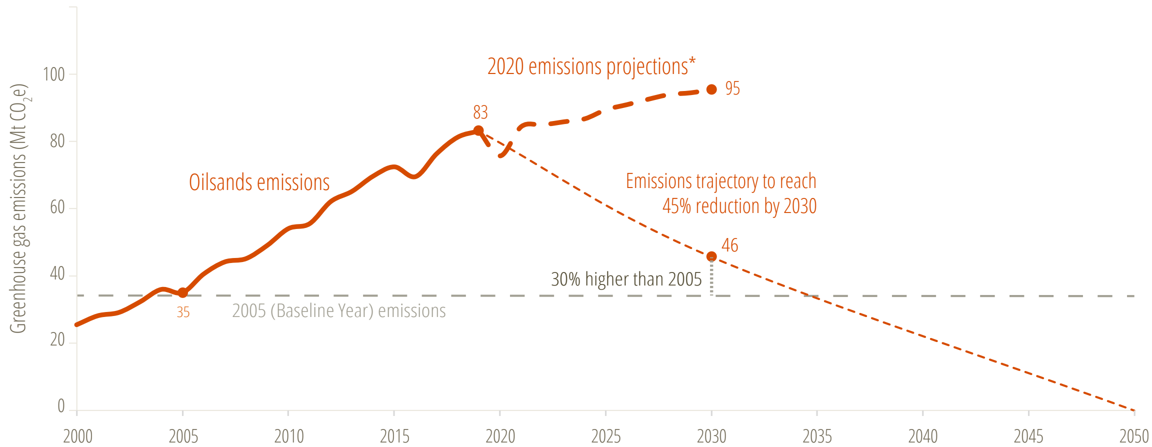

Figure 1. Potential emissions reduction trajectory for oilsands based on a cap and decline from 2019 emissions levels

Data source: ECCC[7]

* This projection is based on the old climate goal of reducing emissions only by 30% by 2030 which depended on larger emissions reductions from all other sectors. New projections are expected to be published by ECCC in April/May 2022.

The federal government now recognizes that Canada's climate goals will remain out of reach in the absence of declining oil and gas emissions. At COP26 in Glasgow, Prime Minister Trudeau repeated a 2021 election platform commitment to cap oil and gas emissions "today" and reduce them "tomorrow".[8] As Figure 1 shows, achieving net-zero emissions in the oil and gas sector by 2050 requires rapid reduction of oilsands emissions. Barring a drastically steeper decline in the oilsands, the conventional oil and gas sector — and possibly other sectors of the economy — will need to decline faster than 45% to achieve Canada's 40–45% reduction relative to 2005 levels by 2030 (Figure 2). While technologies such as new methods of carbon capture could deliver steeper reductions after 2030,[9] their widespread adoption is challenging and cannot be relied upon to deliver reductions aligned with Canada's 2030 goals. The sooner every sector of the economy, including the oil industry, dramatically reduces emissions, the more likely a fully decarbonized economy can be achieved by 2050.

[7] *Canada's Greenhouse Gas and Air Pollutant Emissions Projections 2020.*

[8] Liberal Party of Canada, *Forward. For Everyone.* (2021), 42. https://liberal.ca/our-platform/

[9] There are many types of CCUS in various stages of development. None have yet proven to be commercially deployed at low CO_2 concentration streams (less than 4%). See Section 5 for more details.

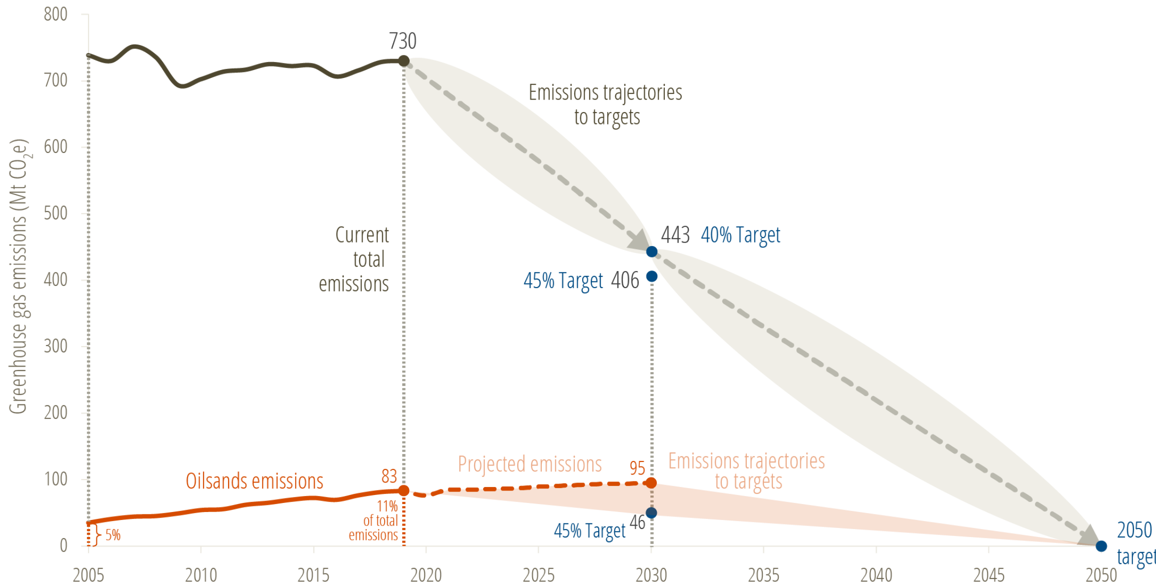

Figure 2. Historical and projected oilsands emissions vs. Canada's 2030 target

Data sources: ECCC[10]

The oilsands 45% by 2030 target of 46 Mt CO_2e is based on 2019 baseline. Canada's commitment of 40%-45% is based on a 2005 baseline. The projected emissions from 2020 to 2030 are based on 2020 ECCC projections, which are expected to be updated in April/May 2022.

1.2 What does net-zero global emissions mean for oil demand?

At a global level, changes in demand for oil will have a direct impact on oil-producing nations and companies. The impact of the COVID-19 pandemic on global oil demand in early 2020 led to a major shock in both price and production levels.[11] Until Q3 of 2021, neither global oil demand nor supply had recovered to 2019 levels. By Q1 of 2022, global oil demand exceeded 2019 levels.

It is clear that notwithstanding short-term volatility, a long-term continuous decline in oil demand starting in the 2020s is essential to reach net-zero emissions by 2050. In the last few years, more detailed global-level scenarios have shown those required declines to be steeper and earlier than previously estimated. The most detailed analysis to date was published in the International Energy Agency's flagship 2021 report, *The World's*

[10] *NIR-2021*, Executive Summary; *Canada's Greenhouse Gas and Air Pollutant Emissions Projections 2020*.

[11] 2020 was the largest annual drop in oil production on record in the U.S. U.S. Energy Information Administration, "U.S. crude oil production fell by 8% in 2020, the largest annual decrease on record," *Today in Energy,* March 9, 2021. https://www.eia.gov/todayinenergy/detail.php?id=47056

Roadmap to Net Zero by 2050, which modelled global oil production dropping to 24 million barrels per day (MMb/d) in 2050 (Figure 3). This would be a continual decline from the historical high of 98 MMb/d in 2019. Another global outlook, this one by British Petroleum (BP), follows a different declining trajectory but arrives at the same demand number of 24 MMb/d in 2050 (not shown).[12]

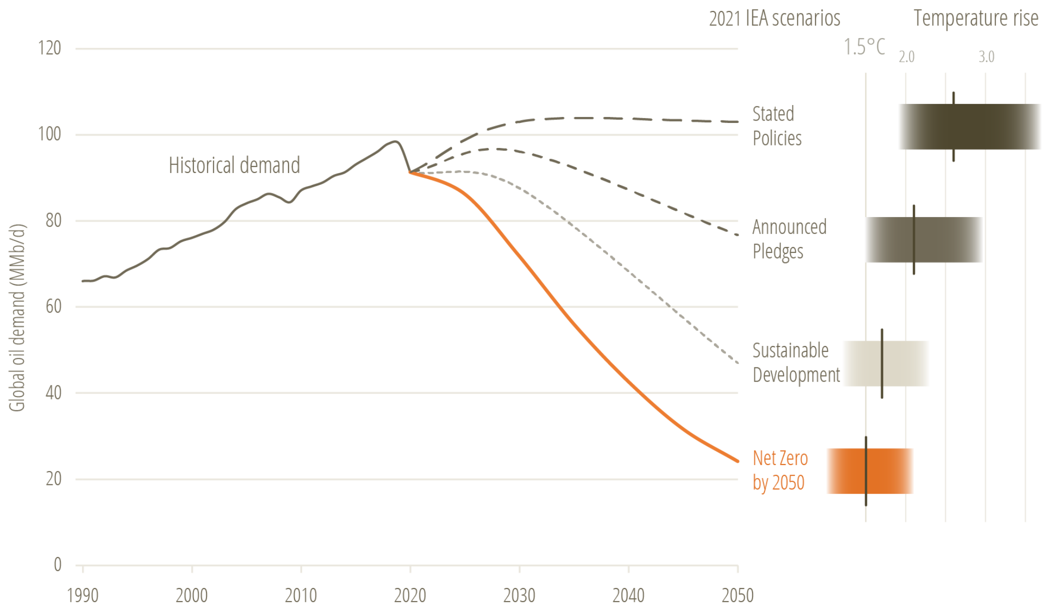

Figure 3. Global oil demand trajectories and associated temperature outcomes

Data sources: IEA,[13,] BP (historical demand)[14].
The middle line in the temperature ranges refer to median temperature rise, meaning there is 50% probability of remaining below a given temperature peak. The full range refers to 5% and 95% percentile in confidence levels.

For the first time, temperature outcomes associated with the different scenarios are included in the IEA's 2021 World Energy Outlook. Figure 3 illustrates how stated policies and announced pledges reflect disastrous and extreme consequences to human

[12] BP, *Energy Outlook* (2020). https://www.bp.com/en/global/corporate/energy-economics/energy-outlook.html. Such projections should not be considered as forecasts. Rather, they are scenarios aimed at defining the policies and investment decisions that will be required to reach a possible future.

[13] International Energy Agency, *World Energy Outlook 2021*. https://www.iea.org/reports/world-energy-outlook-2021

International Energy Agency, *Net Zero by 2050: A Roadmap for the Global Energy Sector* (2021). https://www.iea.org/reports/net-zero-by-2050

International Energy Agency, *World Energy Outlook 2021*. "Scenario trajectories and temperature outcomes," October 8, 2021. https://www.iea.org/reports/world-energy-outlook-2021/scenario-trajectories-and-temperature-outcomes

[14] BP, *Statistical Review of World Energy* (2021). https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html

life and well-being, with peak temperatures rise ranging between 2.4°C–2.8°C in the stated policies scenarios and 1.9°C–2.3°C in the announced pledges scenario. Clearly, greater policy ambition is needed from all major emitting countries, including Canada (which ranks in the top 10 globally).

For the Canadian oilsands industry, there are regional considerations with regard to oil demand in addition to the global trends. The vast majority of Canadian crude exports go to various regions in the United States, historically defined as Petroleum Administration for Defense Districts (PADDs).[15] This means oilsands crudes are more sensitive to regional demand in the U.S. than they are to global oil demand. With several U.S. states having zero-emissions vehicle mandates, and the Biden administration planning to ramp up investment to lower demand for oil in transportation, this shift in U.S. demand is already underway.

Investors and governments have formally recognized the impact of an unstable climate on their portfolios, assets, and economies. As oil demand diminishes, the focus will be on how each region and country will manage their own energy needs in ways that maintain access to secure and affordable supply; enhance the competitiveness of local industries that provide good jobs; and, most importantly, transition to low- and zero-carbon forms of energy in ways that make the most sense given specific national and regional needs.

The notion that climate policies are punitive to economies is also shifting. Studies and announcements at COP26 indicate that both countries and investors now see massive economic opportunities in transitioning to low-carbon economies.[16]

Governments are also moving beyond local emissions to address carbon leakage.[17] Large economies are actively discussing new measures such as an international carbon price

[15] The Petroleum Administration for Defense Districts (PADDs) are geographic aggregations of the U.S. into five regions. During World War II the Petroleum Administration for War, established by an executive order in 1942, used these five districts to ration gasoline. PADDs are still used to define crude allocation and movements across the U.S. U.S. Energy Information Administration, "PADD regions enable regional analysis of petroleum product supply and movements," *Today in Energy,* February 7, 2012. https://www.eia.gov/todayinenergy/detail.php?id=4890

[16] J.F. Mercure et al., "Reframing incentives for climate policy action," *Nature Energy* 6 (2021). https://doi.org/10.1038/s41560-021-00934-2

[17] Carbon leakage occurs when, for reasons of costs related to climate policies, businesses transfer production to other countries with lower emission constraints. The risk of carbon leakage may be higher in certain energy-intensive industries.

floor[18] and carbon border adjustment mechanisms.[19] As more trading nations move to set carbon pricing on fossil fuels, the leakage risk is lower and therefore protections within output-based pricing systems for energy-intensive and trade-exposed sectors can be adjusted. Any shift in that direction would result in higher climate-related costs for the oilsands producers which currently see carbon levies applied to a small percentage of their crude output.

In its February 2020 report, the Pembina Institute outlined the oilsands' emissions trajectory as it related to Canada's commitments to reduce emissions and meet 2030 and 2050 emissions targets. The purpose of this follow-up report is to support more robust discussion and engagement on the pathways to net-zero that has been put forward by Canadian oilsands companies. We do that by exploring the extent to which different technologies can meet the challenge of decarbonizing the oilsands to meet critical emissions reductions targets by 2030 and 2050.

This report presents a snapshot of current decarbonization technologies and solutions, with a greater emphasis placed on technologies that can be implemented between now and 2030 while highlighting the potential for technologies that can mature between 2030 and 2040. Those long-term technological innovations were characterized as "wild cards" by the Canadian Institute for Climate Choices because the pace and scale of their deployment by industry remains uncertain.[20] The focus of this report will be mainly on upstream emissions given that end-use emissions of crude oil products have very different technological and policy options. When the data is available, we will refer to life cycle analysis results when discussing a specific technology to demonstrate its full impact. In section 2.2, we compare climate plans for major oil and gas companies in Canada, the U.S. and Europe that have made commitments to reduce emissions.

[18] Ian Parry, Simon Black and James Roaf, "Proposal for International Carbon Price Floor", *International Monetary Fund*, June 18, 2021. https://www.imf.org/en/Publications/staff-climate-notes/Issues/2021/06/15/Proposal-for-an-International-Carbon-Price-Floor-Among-Large-Emitters-460468

[19] Ewa Krukowska, "Here's How the EU Could Tax Carbon Around the World," *Bloomberg*, June 23, 2021. https://www.bloomberg.com/news/articles/2021-06-24/here-s-how-the-eu-could-tax-carbon-around-the-world-quicktake

[20] Canadian Institute for Climate Choices, *Canada's Net Zero Future: Finding our way in the global transition* (2021). https://climatechoices.ca/reports/canadas-net-zero-future/

What are the oilsands?

Canada has the third-largest oil reserves in the world with 166 billion barrels of crude oil, 97% found in the oilsands of northern Alberta.[21] The oilsands are the fastest-growing source of Canadian oil, increasing in production from 2010 levels by 92% to reach 2.95 million barrels per day in 2019.

The bitumen extracted from the oilsands is a thick, sticky and viscous form of crude oil, characterized by the industry as extra-heavy oil.[22] Unlike light crude oil, bitumen must either be heated or diluted in order to flow.

Bitumen accessible by mining comprises about 20% of oilsands reserves (in 2019 it accounted for almost half of oilsands extraction). The other 80% of Alberta's oilsands reserves are too deep to be accessed from an open pit mine and can only be extracted through in situ — or "in place" — methods. Steam-assisted gravity drainage (SAGD) is the dominant method of in situ extraction, followed by the similar but more energy and emissions intensive cyclic steam stimulation (CSS) method.[23]

Because bitumen can't naturally flow through a pipeline, it is converted into marketable products either by diluting or upgrading before being sent for refining. Mined bitumen has historically been upgraded because high levels of impurities (e.g. asphaltenes) prevent it from meeting pipeline specifications even when diluted. Bitumen upgraded into a synthetic crude oil (SCO), with characteristics that are similar to lighter sweet crude oils, can theoretically be processed by most refineries.

Meanwhile bitumen extracted in situ, which contains fewer impurities, has traditionally been diluted. Diluted bitumen, or dilbit, can only be processed in high-conversion refineries specifically equipped to work with heavy crude oils.

[21] Natural Resources Canada, "What are the oil sands?" 2019. https://www.nrcan.gc.ca/our-natural-resources/energy-sources-distribution/clean-fossil-fuels/what-are-oil-sands/18089

[22] Raw bitumen generally has an API gravity below 10°, which makes it an extra-heavy crude oil. When this bitumen is diluted to meet pipeline specifications, it becomes dilbit, with an API gravity corresponding to that of heavy oil. In other words, oilsands bitumen is extra-heavy oil, but its marketable products are either heavy oil (e.g. dilbit) or light oil (e.g. synthetic crude oil).

[23] Natural Resources Canada, "Oil Sands Extraction and Processing." https://www.nrcan.gc.ca/our-natural-resources/energy-sources-distribution/clean-fossil-fuels/oil-sands-extraction-and-processing/18094

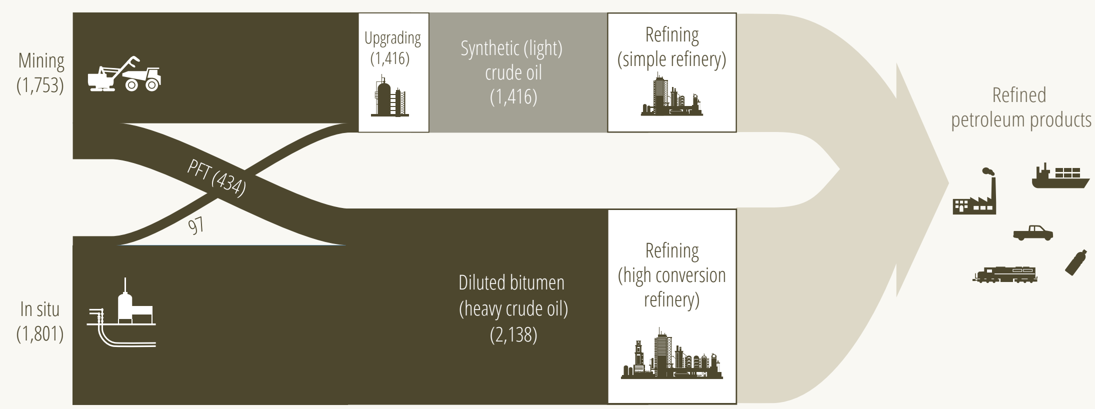

Figure 4. Capacity of existing oilsands pathways (thousand barrels per day)

Data source: Oil Sands Magazine[24]

The two main pathways used to convert oilsands bitumen into refined petroleum products require more energy-intensive processing than most conventional oils, which translates into additional carbon emissions. Diluted bitumen is a heavy crude oil with a high sulphur content, and thus requires more processing than lighter crudes to be transformed into transportation fuels. Meanwhile, upgrading involves energy-intensive processes, and is generally associated with more carbon pollution on a per-barrel basis than refining straight bitumen. Paraffinic froth treatment (PFT), however, is an extraction method that allows mined bitumen to meet pipeline standards.[25] In 2020, 39% of raw bitumen was sent for upgrading, but this proportion is expected to decrease in coming years due to fixed upgrading capacity combined with expected growth of in situ production.

Where do emissions from oilsands facilities come from?

Emissions from oilsands are typically divided by facility type: mining and extraction (19%), in situ (51%), and upgrading (30%) as seen in Figure 5. In the context of emissions reductions technologies and solutions, it is critical to distinguish between these three categories as well as the nature of the emissions sources within each facility and operation. For example, distributed sources such as mobile equipment and fugitive emissions from tailings ponds make up 18% of oilsands upstream emissions. These emission sources do not currently have a reduction pathway and will be the hardest to

[24] Oil Sands Magazine, "Mining Operations"; "Thermal In-Situ Facilities"; "Bitumen and Heavy Oil Upgraders." Accessed July 3, 2021. https://www.oilsandsmagazine.com/projects

[25] The PFT technology drastically reduces impurities, such as asphaltenes, contained in mined bitumen, allowing it to be diluted to meet pipeline specifications — therefore removing the requirement of upgrading.

mitigate. By contrast, emissions from hydrogen production represents approximately 9% of all oilsands emissions and could be mitigated with relatively lower-cost solutions such as carbon capture.

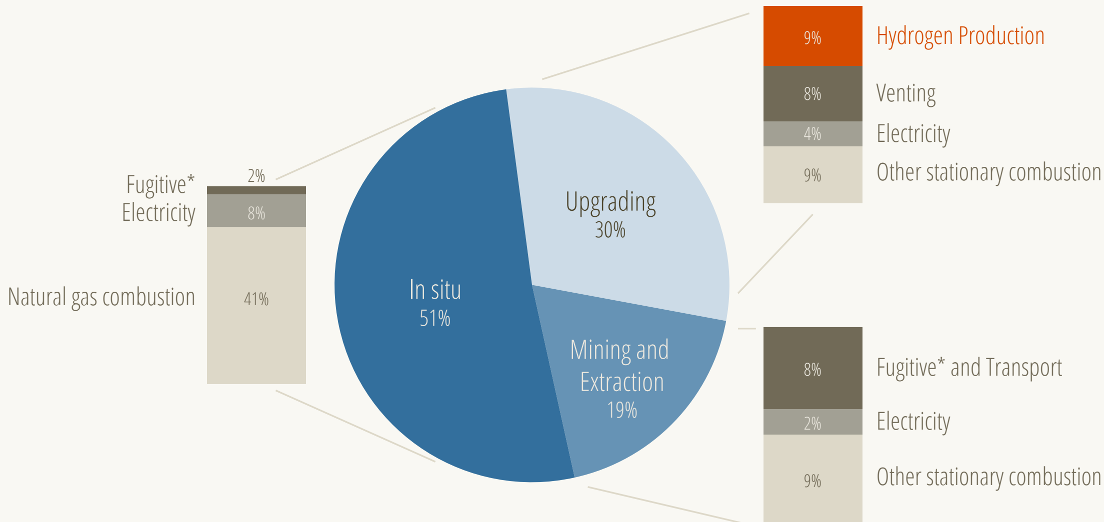

Figure 5. Breakdown of oilsands upstream emissions for 2019

Data sources: ECCC,[26] Pembina Institute[27]

[26] *NIR-2021*, Table A10–3.

[27] Jan Gorski, Karen Tam Wu, Tahra Jutt, *Carbon intensity of blue hydrogen production: Accounting for technology and upstream emissions* (Pembina Institute, 2021). https://www.pembina.org/pub/carbon-intensity-blue-hydrogen-production

2. Decarbonizing the oilsands

2.1 The four key challenges

This section addresses the four main challenges faced by the Canadian oilsands when it comes to decarbonization: the relatively high emissions intensity; the historical rise in absolute emissions from production growth; the difficulty of retrofitting existing upstream facilities, and the problem of end-use emissions. The three first challenges are specific to the oilsands while the fourth is common to all fossil fuels.

2.1.1 The nature of oilsands emission intensity

As previously described, the oilsands are classified as an extra heavy oil that require a significant amount of energy to extract, process and transport. Emissions intensity from each oilsands facility differs, depending on characteristics of the field, facility type and extraction process. However, the average life cycle oilsands carbon intensity is found to be amongst the top tier of the world's most GHG intensive crude oils.[28]

Unlike conventional upstream oil production, oilsands mining emissions include unique sources such as fleets of some of the largest haul trucks in the world; enormous tailings ponds that can continue to generate fugitive emissions of methane for many years; and construction and land disturbance on a very large scale. These emissions sources represent a unique decarbonization challenge given their massive scale and dispersed nature. Unlike concentrated point source emissions, these distributed sources will require investments that match the scale of the challenge, and address not only the GHG emissions, but the cumulative environmental impact of oilsands mining and tailings operations. Figure 6 shows that oilsands intensity has indeed declined but remains higher than any other type of oil and gas produced in Canada.

[28] While there is variability between different oilsands facilities, life cycle GHG intensity of all oilsands remains higher than most conventional crudes.

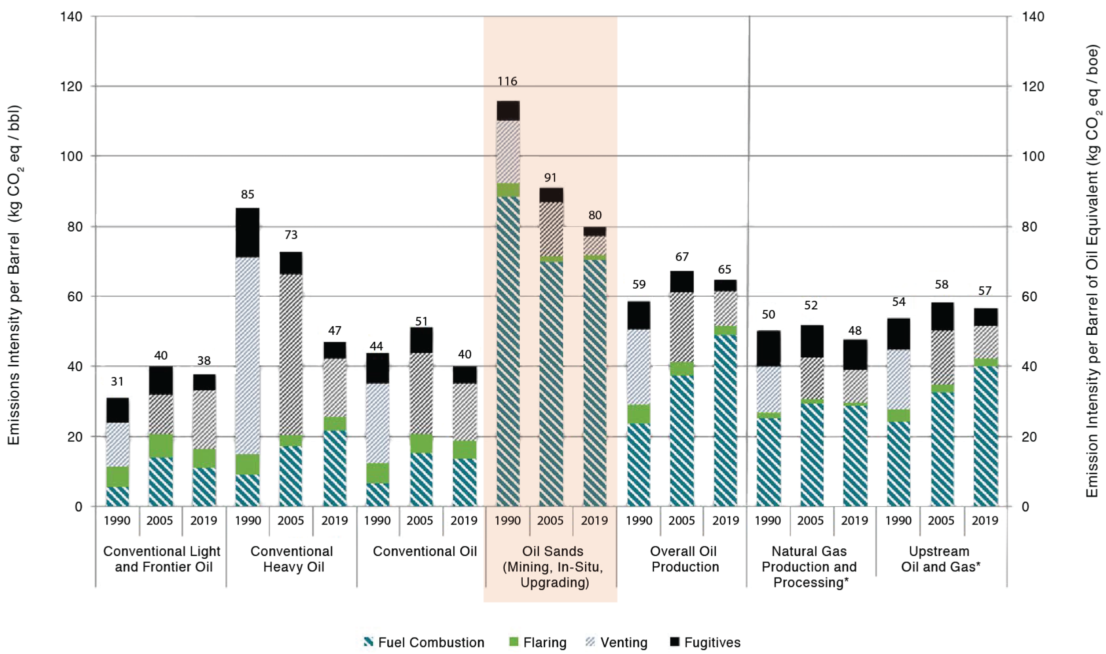

Figure 6. Emissions intensity by source type for oil and gas (1990, 2005 and 2019)

Source: ECCC[29]

The bulk of oilsands emissions come from fuel combustion which represents an opportunity to further reduce point source combustion emissions.

Methane, a greenhouse gas 84 times more potent than CO_2, constitutes a significant source of emissions for most conventional crudes, and best practices and technologies exist to control methane in conventional oil operation at a relatively low cost. In contrast, methane is not the focus for oilsands emissions as it represents a very small component of overall emissions. The majority of methane emissions in oilsands are generated by tailings ponds for which there currently are not many viable technological solutions for capture and control unless investments are made with higher marginal cost of abatement.[30]

Overall, a wide range of solutions are required to address the multiple sources of emissions across the entire oilsands value chain.

[29] *NIR-2021*, Figure 2-25.

[30] ICF International, *Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries* (2015). Available at https://www.pembina.org/reports/edf-icf-methane-opportunities.pdf

2.1.2 The 137% increase relative to Canada's 2005 baseline

Reductions in carbon intensity in the oilsands start from a high baseline and have been outpaced by the significant rise in absolute emissions resulting from production growth. As shown in Figure 7, no other sub-sector of the Canadian economy has seen emissions rise faster than the oilsands, which has increased emissions from 35 Mt CO_2e in 2005 to 83 Mt CO_2e in 2019, a 137% increase (while production rose by 194% over the same period). If the goal is net-zero emissions by 2050, then oilsands has to reduce emissions on average by approximately 2.7 Mt CO_2e each year. Reduction plans that rely on technology not yet deployed at commercial scale would result in a flatter curve in the near term and steeper one in later years. The result would be higher emissions in the short term and large degree of uncertainty for long-term success.

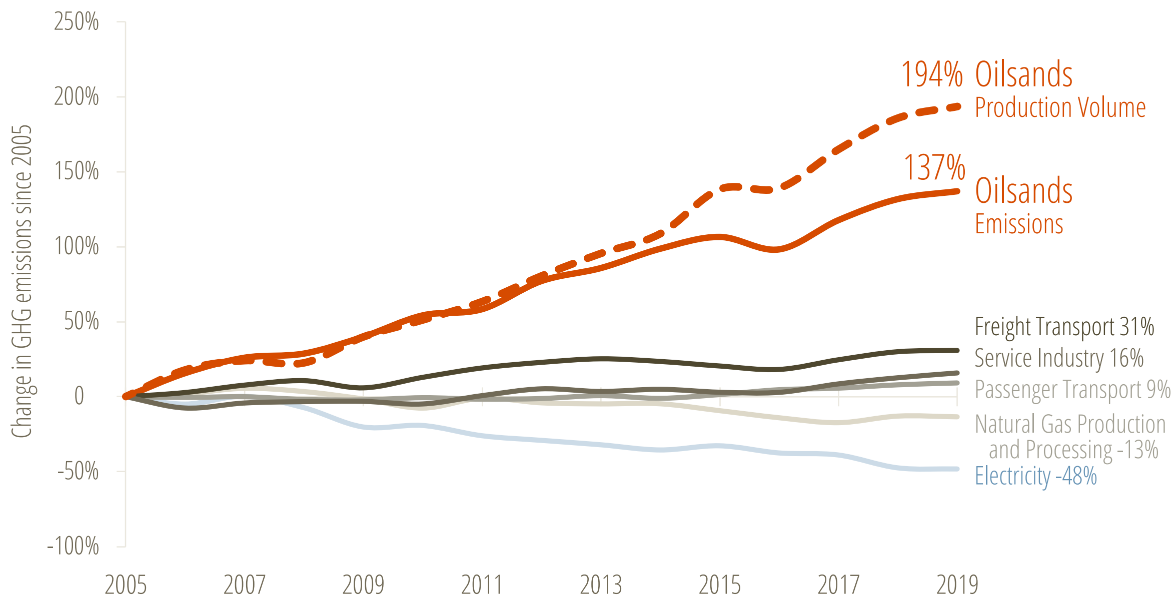

Figure 7. Changes in emissions in different Canadian sub-sectors 2005–2019 vs. changes in oilsands production volumes

Data sources: ECCC,[31] CER[32]

2.1.3 The retrofit challenge

The oilsands is an industry characterized by multi-billion-dollar projects with facilities designed to operate for 25 to 50 years. Because of this long operating life, technologies that are applicable only to new facilities will have low impact on overall oilsands

[31] *NIR-2021*, Table A10-2.

[32] Canada Energy Regulator, *Canada's Energy Futures 2020 Supplement: Oil Sands Production* (2020). https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2020oilsands/index.html

emissions. As of late 2021, no greenfield oilsands projects are moving ahead. As investors of oilsands companies are sharply focused on capital allocations, sanction decisions of new production have been much lower despite crude oil prices going up over $90/barrel. It is highly uncertain whether expansions predicted by the Canada Energy Regulator's 2021 oilsands production outlook (Figure 8) will occur. Until 2021, oilsands production forecasts have consistently been downgraded to reflect lower growth.[33] As a result, the focus of oilsands decarbonization must be on existing facilities.

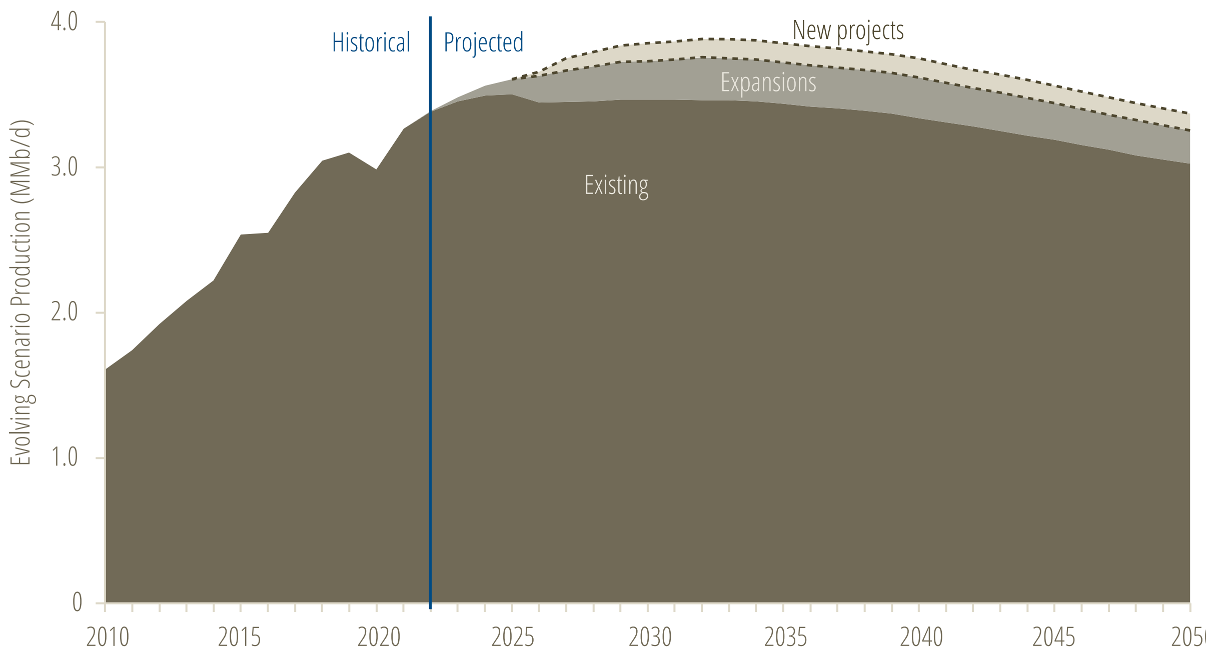

Figure 8. Projected oilsands production, new vs. existing

Data source: CER[34]

Retrofit solutions will also be challenging to plan given the variability across the oilsands industry, including differences in production technologies, reservoir and facility characteristics, and carbon intensity. Producers will need to continue to reduce their operating costs to remain competitive in a volatile international market. It may

[33] Celina Hwang and Kevin Birn, "Canadian oil sands running above pre-pandemic highs, but the lingering impacts of COVID-19 and acceleration of energy transition have lowered the growth prospects," *IHS Markit*, June 23, 2021. https://ihsmarkit.com/research-analysis/canadian-oil-sands-running-above-prepandemic-highs.html

[34] Canada Energy Regulator, *Canada's Energy Futures 2021,* Figure R.10: Oil Sands Production: Existing vs. Projected Additions in the Evolving Policies Scenario. https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2021/results.html

have been difficult in the past to allocate capital to solutions that increase production costs, though a rising carbon tax and other regulatory requirements could increase the economic incentives for such investments.

2.1.4 The need to assess technologies on a life cycle basis

As with all fossil fuels, the majority of the emissions associated with oil from the oilsands occurs when end-use products such as gasoline are combusted. Life cycle product GHG intensity is estimated by calculating the GHG emissions associated with one unit of the production, such as one barrel,[35] through each stage of the product life cycle. The methodology used to estimate this is called a life cycle assessment.[36]

The accounting of emissions for companies and countries depends on the boundaries used to define which parts of the life cycle emissions are accounted for. For example, the end-use emissions of oil exported from Canada is not accounted for in Canada's share of emissions. However, the impact to climate is the same regardless of the accounting rules used.

Therefore, technologies that shift emissions from upstream production to later steps in the value chain cannot be counted as true emissions reduction solutions. The opposite is also true: technologies that may increase the upstream emissions but lower the life cycle emissions have a net reduction. The best way to account for these differences is to assess decarbonization technologies on the full life cycle of the product, regardless of how the products changes hands through its life cycle.

In general, about 10–30% of emissions occur during the well-to-tank portion also known as upstream, with the remaining 70–90% of GHGs emitted from the end use of fuels (Figure 9). In the context of assessing the emission reduction potential of technologies, often the claims of different technology providers do not define the full life cycle boundary, which makes it harder to assess the true climate impact. For example, a 20% reduction in intensity in a step that only represents 10% of life cycle emissions means only a 2% reduction in total emissions intensity. Life cycle analyses have shown that the global climate impact from improving only the upstream

[35] Intensity units can be per volume such as kg CO_2 per barrel of the specific intermediate product such as SCO, or by the energy embedded in one barrel in Megajoules (MJ).

[36] Sometimes referred to as well-to-wheel assessment, a life cycle assessment accounts for all associated emissions, including fuel end use such as combustion in a vehicle's engine. Well-to-wheel represents the most common and the best way to compare the emissions intensities of various crudes.

performance of specific facilities can be highly limited.[37] This is one of the reasons why different types of emissions require different regulatory policies.

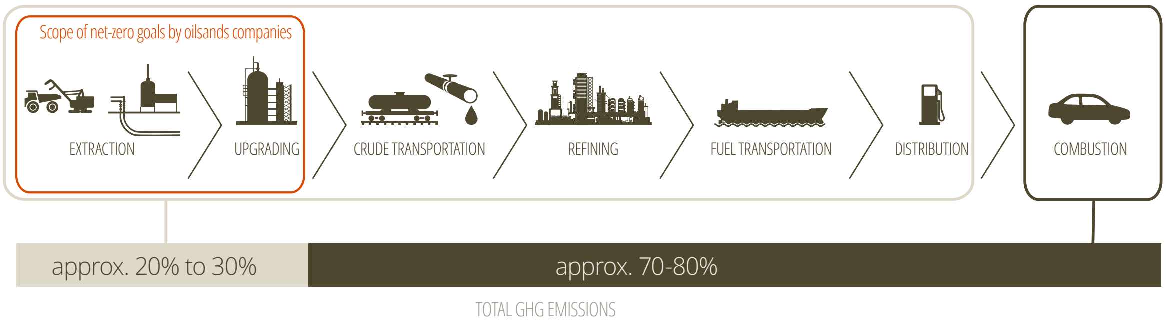

Figure 9. Life cycle GHG emissions from transportation fuels

Note: Some life cycle assessments do not include emissions associated with land use changes and construction, although their inclusion is deemed best practice. Also, not all bitumen is upgraded in upstream production facilities.

2.2 Corporate net-zero plans

With increased awareness and pressure by governments and investors, net-zero commitments by oil and gas companies are increasingly common. Stakeholders are setting increased expectations from corporations to have credible net-zero plans. Banks and investors are demanding disclosure of climate risk and strategies to manage it, and corporate performance on the issue is beginning to factor into the cost of capital. Action on climate change has moved from a sustainability and environmental issue to a risk management one that is central to a company's long-term strategic planning and economic outlook.

The following section considers what makes a credible climate plan for an oil and gas company. It looks at how climate commitments made by Canadian oilsands companies compare to ones made by U.S. and European producers, and how oil and gas company plans stack up against net-zero standards that are beginning to be set by investors.

In 2020, the Pembina Institute published a report titled *How to Get Net-Zero Right,* which argued that the real measure of success is whether emissions are kept at a level

[37] Sylvia Sleep et al., "Improving robustness of LCA results through stakeholder engagement: A case study of emerging oil sands technologies," *Journal of Cleaner Production* 281 (2021). https://www.sciencedirect.com/science/article/pii/S095965262035321X

compatible to the 1.5°C goal.[38] Figure 10 below shows that while net-zero is the destination, how we get to net-zero, and the interim targets in the coming decade, are the key measures of success.

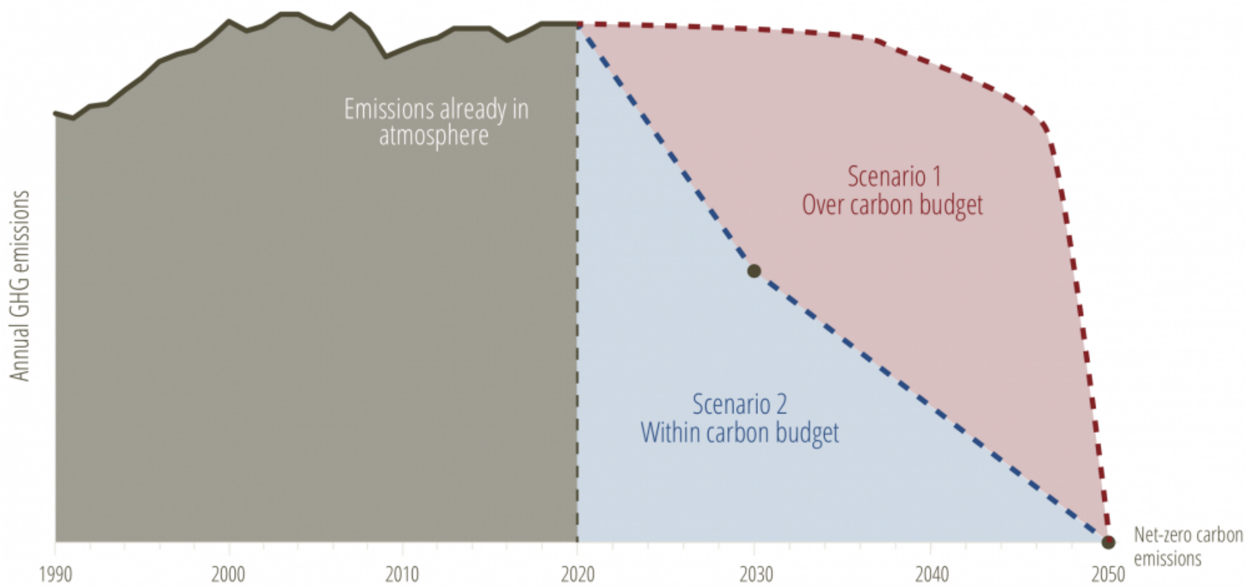

Figure 10. Safe versus dangerous pathways to net-zero emissions by 2050

Scenario 1 (red) achieves net-zero but fails to safely limit temperature rise because it does not use a carbon budget and delays emissions reductions, resulting in a much greater release of total emissions into the atmosphere in the same time period. Scenario 2 (blue) uses early, deep, and sustained emissions reductions in adherence with a climate budget to achieve emissions mitigation required to limit global temperature rise to 1.5°C.

Investors seeking to measure the credibility of net-zero plans are adopting net-zero standards specific to oil and gas companies[39] that not only include targets for emissions reduction by 2030, but also include Scope 3 emissions. Larger European-based oil producers have indicated net-zero targets that are more inclusive of Scope 3, though these targets are baselined differently between companies and often lack many of the elements to make them consistent with 1.5°C.

[38] Isabelle Turcotte and Nichole Dusyk, *How to Get Net-Zero Right: Principles, tools and steps for safe, inclusive net-zero pathways* (Pembina Institute, 2021). https://www.pembina.org/pub/how-get-net-zero-right

[39] Institutional Investors Group on Climate Change, *Net Zero Standard for Oil and Gas companies* (2021). https://www.iigcc.org/resource/net-zero-standard-for-oil-and-gas-companies/

Elements of a credible net-zero plan

- Path is anchored in science with a clear global outcome, **limiting warming to 1.5ºC**
- Plan includes **near-term targets (2030)** and is supported by **capital deployment** and **early steady reductions** rather than later sharper declines
- Plan demonstrates **credible understanding** of how achievement of near-term targets creates a viable path to **long-term goal of net-zero by 2050**
- Plan and targets include end-use **(Scope 3) emissions** to decarbonize the value chain
- Plan demonstrates real progress and meaningful impact in **annual goals and plans**
- Emissions accounting is **transparent, verified and audited** by a credible third party
- Intermediate targets show **reduction in both intensity and absolute basis**
- Management, board and staff **remuneration linked to meeting climate goals**
- Lobbying efforts are in support of strong climate policies

2.2.1 Comparing different oil and gas companies' climate plans

Table 1 lists climate commitments made by the main Canadian, U.S. and European oil producers as of January 2021 to contribute to global carbon neutrality by 2050. Compared to an earlier version of the same table published by the Pembina Institute in 2020,[40] the bar on climate plans continues to evolve. As companies compete for capital in a global marketplace, Canadian oil and gas companies are also facing growing competition on strategies for carbon reduction and innovation.

Emission scopes and boundaries for corporations

Scope 1 correspond to direct emissions from facilities and assets that are owned or controlled by the company.

Scope 2 associated with the purchase of energy used on its sites (e.g. electricity, steam).

Scope 3 includes all other indirect emissions that a company generates, such as from the goods and services it purchases to the end use and disposal of the products it sells.

Net equity vs. operational boundary:
An operational boundary accounts for emissions from all assets under the company's direct operational control even if the company does not own 100% of the asset. An equity boundary includes only the share of what company owns in assets regardless of who has operational control. The most transparent way is to report both methods.

[40] Benjamin Israel, "Evaluating the climate ambitions of Canadian oil companies," *Pembina Institute,* Nov. 18, 2020. https://www.pembina.org/blog/climate-ambitions-canadian-oil

Table 1. Main Canadian, U.S., and European oil producers' emissions reduction pledges (February 2022)

Company	Intermediate GHG Emission target	Corporate Net-Zero	Absolute target 2030	Scope		
				1	2	3
Canadian oilsands companies						
Cenovus	Reduction in absolute emissions by 5% by 2026 and 35% by 2035 (2019 GHG emissions intensity baseline of ~24 Mt CO_2e on net equity basis)	2050	✓	✓	✓	✗
CNRL	Reduction in oilsands emissions intensity by 25% by 2025 (2016 baseline)	Year unspecified*	✗	✓	✓	✗
Imperial Oil	Reduction in oilsands emissions intensity by 30% by 2030 (2016 baseline)	2050[††]	✗	✓	✓	✗
MEG Energy	Reduction in bitumen[†] emissions intensity by 30% by 2030 (2013 baseline)	2050	✗	✓	✓	✗
Suncor	Reduction in emissions intensity by 30% by 2030 (2014 baseline) Reduction in absolute emissions by 5 Mt Scope 1,2 another 5 Mt from variable sources by 2030 (2019 GHG emissions of 29 Mt baseline on net equity basis)	2050	✓	✓	✓	✗
U.S. companies						
Chevron	Reduction in Portfolio Carbon Intensity PCI >5% by 2028 (2016 baseline)	2050	✗	✓	✓	✓
Conoco-Phillips‡	Reduction in emissions intensity by 35–45% by 2030 (2017 baseline) With active advocacy for a price on carbon to address end-use (Scope 3) emissions.	2050	✗	✓	✓	✗
ExxonMobil	Reduction in corporate wide GHG intensity by 20–30% and absolute emissions by 20% by 2030 (2016 baseline). For oilsands see Imperial Oil's pledge	2050	✓	✓	✓	✗
Occidental	Reduction in Scope 1 and 2 by 2040, total emissions by 2050	2050	✗	✓	✓	✓

European companies						
B.P.	Reduction in operational emissions by 20% by 2025 and by 30–35% by 2030; reduction in products emissions intensity by 5% by 2025, 15% by 2030, 50% by 2050 (2019 baseline)	2050	✓	✓	✓	✔
Equinor ‡‡	Carbon-neutral operations (Scopes 1 and 2) by 2030; reduction in absolute emissions (Scopes 1 and 2) in Norway by 40% by 2030, 70% in 2040, near-zero in 2050; reduction in products' net carbon intensity by 100% by 2050	2050	✔	✓	✓	✔
Repsol †††	Reduction in emissions intensity by 15% by 2025, 28% by 2030, 55% by 2040 (2016 baseline) , includes reduction 55% of Scope 1 and 2.	2050	✔	✓	✓	✔
Shell	Reduce absolute emissions by 50% by 2030, (2016 baseline net equity)	2050	✓	✓	✓	✔
Total Energies	Reduction in emissions intensity of energy products sold worldwide by 15% by 2030, 35% by 2040, 60% by 2050 (100% by 2050 for European customers)	2050	✓	✓	✓	✔

Legend: ✓ Target included ✔ partially included ✗ Target not included

Notes: When referring to emissions reduction, this means from all operations. When referring specifically for oilsands or bitumen emissions, this does not include emissions reduction targets for their conventional oil and gas production operations or methane mitigation targets.

* Net-zero target is limited to oilsands and does not include total corporate emissions. Equity share of non-operated assets not included in Scope 1.

† Bitumen GHG Intensity is reported to be roughly 7% higher than the Net GHG Emission Intensity

†† Imperial Oil has not independently announced a net-zero goal. We assume that the goal set by Exxon includes Imperial oil.

‡ Conoco-Phillips is part of the *Oil Sands Pathways to Net Zero.* Average bitumen daily net production was reported at 60,000 bpd which makes 4.5% of total production in 2019 Assumed to include Scope 2 emissions although company disclosure is not explicit

‡‡ Equinor's absolute reductions baseline year is 2005. Scop 1 and 2 are based on operational boundary where scope 3 is on equity basis and excludes non-combustion products.

††† Repsol's Scope 3 is based on the use of the products from only their upstream product. Also has a 2025 interim absolute target of 1.5 Mt CO_2e , but not a 2030 absolute target.

Data sources: Various[41]

[41] Cenovus, *2019 Environmental, Social & Governance Report* (2020). https://www.cenovus.com/reports/2019/2019-esg-report.pdf

Canadian Natural, *2019 Report to Stakeholders* (2020). https://www.cnrl.com/upload/media_element/1313/02/2019-stewardship-report-to-stakeholders.pdf

Husky, *ESG Report 2020* (2020). https://huskyenergy.com/downloads/abouthusky/publications/sustainabledevelopment/ESG-Report-2020/Husky-ESG-Report-2020.pdf

Imperial Oil, *Corporate sustainability report* (2021). https://www.imperialoil.ca/-/media/Imperial/Files/Publications-and-reports/IMP-0020-Sustainability-Report_final_web_March-29.pdf

Imperial Oil, *Press Release* (2022). https://news.imperialoil.ca/news-releases/news-releases/2022/Imperial-sets-2030-oil-sands-emission-intensity-reduction-goal-expects-to-meet-2023-objective/default.aspx

MEG Energy, *Environmental, Social & Governance (ESG) Report* (2020). https://www.megenergy.com/sites/default/files/2019MEGEnergyESGReport.pdf

Suncor Energy, *Climate Report 2021* (2021). https://sustainability.suncor.com/-/media/project/ros/shared/documents/climate-reports/2021-climate-report-en.pdf

Chevron, *Climate Change Resilience* (2021). https://www.chevron.com/-/media/chevron/sustainability/documents/2021-climate-change-resilience-report.pdf

ConocoPhillips, *Managing Climate-Related Risks* (2019). https://static.conocophillips.com/files/resources/20-0737-climate-change-report-2020-fnart.pdf

ExxonMobil, Updated *2021 Energy & Carbon Summary* (2021). https://corporate.exxonmobil.com/-/media/Global/Files/energy-and-carbon-summary/Energy-and-Carbon-Summary.pdf?la=en&hash=9C9C45F0660AEB09B71D140B200C565B40D46872

ExxonMobil, Updated *Advancing Climate Solutions 2022 Progress Report* (2022). https://corporate.exxonmobil.com/-/media/Global/Files/Advancing-Climate-Solutions-Progress-Report/2022/ExxonMobil-Advancing-Climate-Solutions-2022-Progress-Report.pdf

B.P., *BP Sustainability Report 2020* (2021). https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/sustainability/group-reports/bp-sustainability-report-2020.pdf

Equinor, *2020 Sustainability Report* (2021). https://www.equinor.com/en/sustainability.html

Repsol, "Our roadmap toward net zero emissions by 2050," (2019). https://www.repsol.com/en/sustainability/climate-change/our-climate-change-strategy/index.cshtml

Shell, "What is Shell's net carbon footprint ambition?" (2020). https://www.shell.com/energy-and-innovation/the-energy-future/what-is-shells-net-carbon-footprint-ambition.html

Total Energies, "Total adopts a new climate ambition to get to net zero by 2050," (2020). https://www.total.com/media/news/total-adopts-new-climate-ambition-get-net-zero-2050

Occidental, "Climate Report 2020," (2020). https://www.oxy.com/Sustainability/overview/Documents/ClimateReport2020.pdf

The pledges listed in Table 1 demonstrate the variability across different companies. First, it is critical to distinguish between intensity-based goals and absolute annual emissions reduction. Each metric is required and is more useful for specific stakeholders and/or contexts. For example, intensity targets allow companies to consistently measure their emissions targets regardless of changes in structure, size, or asset mix. They also allow for relative comparisons between similar companies, facilities, and projects (if calculated the same way across companies). Having only an intensity target, however, does not ensure actual emissions reductions. In the case of oilsands, improvements in emissions intensity per barrel were outpaced by the rapid increase in production which led to the continuous rise in absolute emissions (Figure 7)

Given the proposed federal cap on oil and gas emissions, it is critical that oilsands producers GHG emissions reduction plans are translated into interim 2025 and 2030 targets and that progress is reported annually. The credibility of climate plans will be tested against the impact on absolute emissions and how these plans impact overall societal net-zero goals.[42] The setting of near-term, science-based targets and annual accountability in meeting them has raised the bar for corporate net-zero plans. Banks, insurance companies and other investors that signed up for the Glasgow Financial Net Zero Alliance have all signed commitment letters in which they pledge to adopt those measures.[43] The global banks that finance oilsands operations — including Canada's big five — have committed to focus their attention on the most GHG-intensive sectors as they pursue their net-zero strategies.

The scope of emissions to be addressed is not consistent across companies. While the financial sector focus on emissions performance is pushing for coverage of Scope 1, 2 and 3 emissions, all major Canadian oil companies pledge to reduce or eliminate only Scope 1 and 2 emissions, estimated to correspond to about 15–30% of emissions in the entire value chain of activities and products. In contrast, all major European oil producers have committed to address some or all their Scope 3 emissions by, for example, starting to adopt strategies and business models that aim to provide their

[42] Institutional Investors Group on Climate Change (IIGCC), "Net Zero Standard for Oil and Gas" (2021). https://www.iigcc.org/news/investors-representing-usd-10-4-trillion-set-out-standard-for-net-zero-transition-plans-in-the-oil-and-gas-sector/

[43] Net-Zero Banking Alliance, "Commitment Statement." https://www.unepfi.org/net-zero-banking/commitment/

customers with low-emissions energy options and help them reduce end-use emissions.[44]

While these goals and disclosures are currently voluntary, such pledges echo the principles of Extended Producer Responsibility (EPR), a policy approach supported by the Organisation for Economic Co-operation and Development (OECD) "under which producers are given a significant responsibility — financial and/or physical — for the treatment or disposal of post-consumer products." Applied to oil production, an EPR approach would see an oil producer taking responsibility for emissions associated with the combustion of transportation fuels and offsetting those downstream emissions.[45]

A version of this obligation was clear in a recent Shell court case where the District Court in the Hague ruled that Shell must reduce its global net carbon emissions by 45% by 2030 compared with 2019, leading Shell's chief executive to respond to the court ruling by declaring the company will accelerate its strategy.

2.2.2 Oilsands producers' net-zero pledges

Despite improvements over the past decade, and a wide range of performance between operations, the oilsands industry as a whole sits at the high end of the global oil supply in two important metrics: per-barrel carbon emissions and incremental production costs.[46,47] While production costs indisputably affect the industry's access to capital, oilsands producers and investors understand that carbon performance is also critical to ensure the viability of the sector over the next decade as the world moves to a low-carbon future.

Carbon competitiveness has become a major strategic consideration across all sectors, particularly for high-emission facilities that are at the forefront of this reality. This was clear when five major oilsands producers announced their Oil Sands Pathways to Net

[44] These are sometimes referred to new energy business units that focus on low, sometimes negative energy such as renewable electric generation and distribution, biofuels with carbon capture. These investments currently represent a very small portion of the total capital invested within oilsands companies.

[45] OECD, "Extended producer responsibility." https://www.oecd.org/env/tools-evaluation/extendedproducerresponsibility.htm

[46] Costs refer to new investments as explained in Aaron Brady, "Global crude oil cost curve shows 90% of projects through 2040 breaking even below $50/bbl," *IHS Markit,* September 10, 2021. https://ihsmarkit.com/research-analysis/global-crude-oil-curve-shows-projects-break-even-through-2040.html

[47] P. Erikson and M. Lazarus, *Examining risks of new oil and gas production in Canada* (Stockholm Environment Institute, 2020). https://www.sei.org/publications/examining-risks-of-new-oil-and-gas-production-in-canada/

Zero initiative in June 2021, expanded in November 2021 to include Conoco Phillips.[48] The alliance of the major oilsands companies released an emissions reduction pathway vision statement that shows a steady reduction to net-zero emissions by 2050 based only on technological and offsets solutions. The vision, however, does have some significant missing pieces:

- The baseline used by the Oil Sands Pathways does not account for all reported oilsands emissions in Canada's National Inventory Report (NIR)[49] which forms the basis for Canada's national climate pledges and policies. The companies use 68 Mt CO_2e using 2018 data while the latest NIR-reported number for 2019 is 83 Mt, leaving a gap of 15 Mt CO_2 from the sector that is not included in its pathways baseline.
- While the proposed pathway shows a combination of technologies, there is an over-reliance on unproven technologies such as next-generation CCUS,[50] nuclear, and a very large use of offsets after 2030. A strong and credible net zero strategy is one that is based on rates of change and technology pathways that are currently viable and achievable. While not impossible, pathways that rely on rapid and successful application of future technologies are certainly less plausible.
- The Oil Sands Pathways initiative does not adequately consider the impact of global efforts to reduce oil demand compatible with limiting global temperatures to 1.5°C. The impact of production decline, resulting from strong climate policy domestically and internationally, is not addressed. While there are legitimate questions as to whether the world will indeed reduce the demand for oil at a pace aligned with 1.5 degrees, it would be irresponsible to base a corporate strategy on a scenario that assumes growing climate impacts from increased global crude consumption.

Oilsands companies have gone on the record referencing their need for public funding support, with an estimated price tag in the order of $30 to $75 billion (US$23 to $60

[48] Oil Sands Pathways to Net Zero, "Pathways plan to achieve net zero emissions," November 3, 2021. https://www.oilsandspathways.ca/the-pathways-vision/

[49] Every year, Canada prepares and submits an official national greenhouse gas inventory to the United Nations Framework Convention on Climate Change. This report is often produced in April and data lags by two years; the 2019 official data was published in April 2021.

[50] This refers to CCUS technologies below TRL of 7 and does not refer to the commercially proven amine-based capture technology employed in facilities such as Quest. See CCUS section for more details.

billion) to decarbonize the sector with an emphasis on CCUS.[51] The Province of Alberta has asked for $30 billion from the federal government[52] and the Canadian Association for Petroleum Producers has asked for grants covering 75% of capital costs for CCUS facilities.[53]

While government has a role to play in de-risking targeted commercialization of specific technologies, CCUS has already been fully commercialized for high-concentration CO_2 streams for oilsands (see Section 5) largely because of direct government support. The current business environment, characterized by relatively high oil prices and lower operating costs, has resulted in very strong financial results for the sector, positioning companies to leverage their financial strength to make no-regret investments in decarbonizing existing production. Furthermore, Ottawa has long pledged to eliminate fossil fuel subsidies; financial aid that supports companies' efforts to produce carbon-intensive fuel would run counter to that commitment.

In a recently published a paper, the Institute of Climate Choices proposed four criteria to evaluate public spending: consistency with global low-carbon transition, value for money, employment outcomes, and policy fit.[54] With the goal of decarbonizing the entire economy, government support needs to include all sectors and prioritize the needs of significantly impacted workers and communities. As CCUS costs come down[55] and climate policy drives investment decisions across all sectors, specific, well-designed and targeted government support will still be needed to develop low-cost decarbonization technologies of the future. The federally proposed investment tax credit for carbon capture on facilities whose emissions feature low concentrations of CO_2 would be one such example.

[51] Robert Tuttle, "Oil sands carbon cuts come with US$60-billion bill, loose ends," *Bloomberg News,* July 8, 2021. https://www.bnnbloomberg.ca/oil-sands-carbon-cuts-come-with-60-billion-bill-loose-ends-1.1626645

[52] Hannah Kost, "Alberta asks federal government to commit $30B to advance carbon capture technologies," *CBC News*, March 8, 2021. https://www.cbc.ca/news/canada/calgary/ucp-federal-government-30-billion-carbon-capture-1.5941518

[53] Rod Nickel, "Exclusive: Oil companies ask Canada to pay for 75% of carbon capture facilities," *Reuters*, October 7, 2021. https://www.reuters.com/world/americas/exclusive-oil-companies-ask-canada-pay-75-carbon-capture-facilities-2021-10-07/

[54] R. Samson, P. Phillips, D. Drummond, *Cutting to the Chase on Fossil Fuel Subsidies* Canadian Institute for Climate Choices (2022). https://climatechoices.ca/wp-content/uploads/2022/02/Fossil-Fuels-Main-Report-English-FINAL-1.pdf

[55] Shell's Polaris project is expected to have lower capture costs and will not require any government support because it is economic on its own.

2.3 Examining technologies

The balance of this report examines decarbonization solutions that could be deployed with current technologies (Section 3) and with future technologies that are still being developed (Section 4). We follow the same classification system used by the Government of Canada to distinguish between different stages of new technology maturity, known as technology readiness level (TRL), where Level 1 is the least ready and Level 9 is already deployed in real-life conditions. See Appendix B for a detailed definition of each technology readiness level. This report focuses as much as possible on techniques that have a TRL of at least Level 5, and that have the potential to be commercialized and deployed by 2030 as well as to retrofit existing oilsands operations (see retrofit challenge Section 2.1.3).

If emission reductions do not occur in the near term, the sector's competitiveness and creditability will be at risk. We explore the role and limitations of specific carbon removal solutions such as carbon capture (Section 5) and negative emissions such as nature-based solutions and direct air capture (Section 6). And finally, Section 7 is dedicated to non-combustion uses for bitumen, an approach to address the Scope 3 emissions of the crude oil life cycle.

3. Current technologies

Section 3 focuses on technologies that, if deployed in existing operations, could incrementally reduce the emissions intensity of the bitumen produced. These technologies alone cannot achieve the objective of net-zero emissions by 2050, or even put companies on a credible net-zero path by 2030. However, they represent a "lowest hanging fruit" as they often — but not always — result in both lower emissions and lower operating costs which make them attractive as lower-risk investments. An accelerated investment to enable large scale deployment of these technologies can add up to achieve earlier reductions in GHG emissions.

3.1 Fuel switching

Fuel switching can improve emissions levels by replacing high-intensity fuels with lower-intensity ones, such as replacing petroleum coke with natural gas or replacing natural gas with electricity or renewable natural gas.

Petroleum coke — a byproduct of the bitumen upgrading process — was the fuel of choice for the first two oilsands extraction facilities,[56] while mines built later used natural gas to generate steam. This shift from coke to natural gas has a limited potential to reduce GHG emissions. According to data published by IHS, petroleum coke represented only 11% of emissions in mining,[57] and while natural gas has approximately half of the emissions intensity of petroleum coke, the overall emissions reduction is in the range of 5–6%.

Of the two existing facilities that use petroleum coke, Suncor announced in 2019 that it is replacing the coke-fired boilers at its Base plant with more efficient natural gas co-generation units.[58] The project is expected to start operations in early 2025, delayed

[56] These are Suncor's Base Plant, which started up in 1967, and Syncrude's Mildred Lake, which started up in 1978. CNRL's Horizon upgrader produces petroleum coke but does not combust it to generate steam, using natural gas instead.

[57] Approximately 9 out of 81 kg CO_2e/bbl of mined SCO, using IHS system boundary, 2019 data. IHS Markit, *The GHG intensity of Canadian oil sands production: A new analysis* (2020). Available at https://ihsmarkit.com/products/energy-industry-oil-sands-dialogue.html

[58] Cogeneration plants use a single fuel source to produce both heat, in the form of steam, and electricity. In oilsands the steam is used for heat and the excess electricity is sold to the power grid.

from its original 2022 timeline.[59] Syncrude's Mildred Lake plant, which burns more coke per volume of bitumen production, has not announced plans to move to less emissions-intensive fuels.[60]

Less carbon-intensive fuels, such as renewable natural gas derived from biomass or waste residue, could in theory substitute for fossil natural gas, the main fuel currently used in the oilsands industry.[61] However, renewable natural gas is currently much more expensive than fossil natural gas and production volume is still low relative to the massive demand required by oilsands facilities. An intentional and strategic investment and low-carbon fuels will be needed to allow for more impactful reductions in absolute emissions.

3.2 Energy efficiency

While energy efficiency measures have delivered noticeable reductions in emissions intensities for a number of oilsands projects, delivering the bulk of emissions reductions to date, these improvements have been largely offset by the growth in oilsands production which has led to an increase in oilsands' overall emissions. If production is increased as forecasted by the Canadian Energy Regulator, oilsands producers would need to retrofit existing operations in ways that move beyond the marginal operational improvements if they are to see reductions in absolute emissions. If production growth stalls, energy efficiency and other operational improvements could provide some marginal reductions in absolute emissions.

With the collapse of global oil prices in 2008–09 and again in 2014, oilsands producers were forced to cut their costs or absorb ongoing losses. Through process improvements to cut costs, fuel use was reduced and by extension so was emissions intensity. Most oilsands producers have put measures in place in the past decades to improve the efficiency of their operations through a better integration of mining and upgrading; the

[59] Suncor, "Coke Boiler Replacement Project." https://www.suncor.com/en-ca/about-us/oil-sands/process/coke-boiler-replacement-project

[60] Phase-out of coke in Mildred Lake could require the replacement of the entire coking unit. Data on coke production, inventory and use as a fuel can be found in Alberta Energy Regular ST39 reports. https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st39

[61] Renewable natural gas has a carbon intensity of 0.29 kg CO_2e/GJ, compared to 49.87 kg CO_2e/GJ for fossil natural gas. B.C. Ministry of Environment and Climate Change Strategy, *2017 B.C. Best Practices Methodology For Quantifying Greenhouse Gas Emissions* (2017), 13. https://www2.gov.bc.ca/assets/gov/environment/climate-change/cng/methodology/2017-pso-methodology.pdf

development of cogeneration units to produce both steam and electricity; or the deployment of driverless trucks that can run more optimally for oilsands mining.[62]

Within oilsands mining, a 2018 IHS Markit report estimated an improvement in emissions levels of 6–10% by 2030 from 2017 levels for the mined Synthetic Crude Oil (SCO) segment.[63] At least some portion of that reduction would be the result of greater energy efficiency.

For in situ production, efficiency improvements result primarily from more efficient use of steam, which is translated into an overall average lower steam-oil-ratio (SOR). There are many contributing factors to lower SOR numbers over time, in some cases due to active efforts to reduce cost by using in-fill wells; co-injecting natural gas with steam; and using inflow control devices. Higher SOR not only correlates with higher emissions but also higher operating costs. This means that operations with high SOR, and by extension high emissions, may not be profitable when crude prices are lower.

What about cogeneration?

Cogeneration expansion was once touted as a promising pathway to lower oilsands emissions as it allowed for using and exporting less emissions-intensive electricity than the grid average. Cogeneration units, especially those deployed for in situ operations, produce steam while also generating electricity to be used either on-site or exported to the grid. An efficient process, cogeneration uses less natural gas to produce steam and electricity than if the two were produced separately using gas-fired units. Cogeneration was deemed to have lower GHG emissions because it can generate power that is less carbon-intensive than coal-fired electricity, which was previously the dominant source of electricity in Alberta. Given the recent accelerated coal phase-out in Alberta by 2023, renewables have become the most cost-effective source of electricity,[64] while providing low to zero emissions. With the promise of reaching a 100% net-zero-emitting electricity system by 2035, co-generation will move from a pathway that reduced emissions intensity to a source of generation that will need to be abated, making cogeneration on its own not compatible with the long-term goal of a net-zero Canada.

---

[62] Efficiency gains come from removing limitations related to human drivers such as the need to take breaks, shift changes, and driving slower in poor visibility conditions.

[63] IHS Markit, *Greenhouse gas intensity of oil sands production* (2018). Available at https://ihsmarkit.com/products/energy-industry-oil-sands-dialogue.html

[64] Jan Gorski and Binnu Jeyakumar, *Reliable, affordable: The economic case for scaling up clean energy portfolios* (Pembina Institute, 2019). https://www.pembina.org/pub/reliable-affordable-economic-case-scaling-clean-energy-portfolios

3.3 Steam displacement technologies

For well over a decade, industry and government have cited steam displacement technologies as key solutions that are expected to deliver major emission reductions if they can be deployed at scale. While promising on paper, those technologies come with technical and cost limitations.

The applicability and performance of these technologies depend on the characteristics of the specific oil reservoirs. More importantly, these techniques are best applied to new wells as opposed to producing wells,[65] which will limit their deployment given that new and expansion projects are expected to represent a marginal portion of future production (see Section 2.1.3).

Steam displacement technologies specifically apply to oilsands produced with in situ techniques, such as SAGD — a type of production expected to provide the bulk of any increased oilsands output currently planned through 2040.[66] In SAGD, steam heated by natural gas is continuously injected via horizontal well to heat bitumen in place. The heat reduces the bitumen viscosity so it can be recovered through a parallel producer well located beneath the injector well. The continuous injection of steam creates a steam chamber that maintains heat and pressure in the reservoir.

For decades, SAGD producers have been investigating ways to reduce the steam-oil-ratio which would reduce the intensity of natural gas use. A lower steam-oil-ratio results in reduced fuel unit costs and lower GHG emissions intensity. One technique is injecting a non-condensable gas such as methane to help maintain the steam chamber pressure and reduce the need for increasing volumes of steam. Another is the use of natural gas liquid solvents, like butane or propane, that chemically dilute the bitumen to reduce viscosity and allow it to flow at lower temperatures. Solvents are injected with or instead of steam in in situ reservoirs, and the solvent is later recovered from the bitumen. A secondary benefit of solvent technology is the reduction in water consumption and/or treatment required. While the use of solvents has been studied for decades, the use of steam remains the dominant method for in situ production.

---

[65] Report of the Standing Senate Committee on Energy, the Environment and Natural Resources, *Canada's Oil and Gas in a Low-Carbon Economy* (2018), 59.
https://sencanada.ca/content/sen/committee/421/ENEV/reports/ENEV_OilGas_FINALweb_e.pdf

[66] Bitumen produced through in situ methods is expected to grow by 54% between 2019 and 2040 and accounts for nearly all expected growth in oilsands production. *Canada's Energy Futures 2020 Supplement: Oil Sands Production.*

Most oilsands companies have developed their own version of steam displacement technology. Table 2 outlines some of these technologies and their readiness levels.

Table 2. Steam displacement technologies for in situ production

Company	Technology	Per-barrel emissions reduction potential	Technology readiness level
Cenovus	Solvent-aided process (SAP)	30%	7–8
Cenovus	Solvent-driven process (SDP)	>30%	7
Imperial	SA-SAGD	25%	8–9
Imperial Oil	Enhanced bitumen recovery technology (EBRT)	60%	5–6
Suncor	Solvent+	50–70%	6
MEG Energy	eMVAPEX	40%	8
Imperial Oil	Cyclic solvent process (CSP)	80%	8

Note: The emissions reduction potentials indicated have not necessarily been verified by an independent third-party and confirmed in a commercial project. The potential for per-barrel emissions reductions uses SAGD as a baseline. However, there are varying SAGD performance baselines. In addition, various companies may employ different methodologies to account for emissions or use different baselines, making the emissions reduction potentials indicated in this table not necessarily comparable between technologies.

In its 2018 outlook, IHS Markit estimated that steam displacement technologies would provide the bulk of SAGD emissions intensity reductions through 2030. The economics of using solvent with steam can be challenging in low crude price cycles when the costs of deploying and recovering solvents is higher than revenues from the incremental production. When the economics are favorable, the deployment of these technologies can reduce the intensity of specific SAGD wells. However, companies are reluctant to introduce new production techniques to all existing sites if costs are higher.

Policy shift to optimize resources

As a requirement for companies holding leases, Alberta compels oilsands operators to mine poor-quality ores at high economic and environmental costs. The result is higher emissions per barrel from extraction operations than would occur if companies targeted high-grade ore only. A regulatory paradigm shift is needed to focus on resource optimization as opposed to resource recovery. The era of conserving oil resources and maximizing their use for future generations is past as the world transitions to a net-zero economy.

Directive 082 established by the Alberta Energy Regulator (AER) in its latest iteration in 2016 provides criteria to determine which resources operators are obliged to mine, as well as the total volume of bitumen that must be recovered, in order to fulfil AER's mandate "to effect conservation and prevent waste of the oilsands resources."[67,68]

Shell conducted a resource optimization pilot project in fall 2016 that assessed private profit, environmental and royalty revenues outcomes. By focusing on the highest grade ores, Shell's pilot project demonstrated reduced tailings fines of up to 18%, an 8–12% reduction in GHGs, and a 3.5-year reduction in the life of the mine.[69] This demonstrates the value of shifting from a quantity-oriented regulatory paradigm to one focused on recovering only Alberta's best quality fossil fuel resources. Amending Directive 82 and changing the requirements for low-grade ore mining could allow for incrementally reducing the sector's emissions.

[67] Alberta Energy Regulator, *Directive 82* (2016). https://www.aer.ca/documents/directives/Directive082.pdf

[68] Government of Alberta, *Oil Sands Conservation Act*, section 3(a). https://open.alberta.ca/publications/o07

[69] Shell, *Waiver Request: Mining Criteria-Directive 082 Shell Canada Energy – Muskeg River and Jackpine Mine Approval No. 8523 & 9756* (2016). https://dds.aer.ca/iar_query/FindApplications.aspx

4. Future technologies

Several emerging technologies have the potential to further decarbonize oilsands upstream emissions. The primary goal of most of these technologies is to replace or eliminate combustion of natural gas while maintaining bitumen production. These technologies either have a narrow application, as in the case of zero-steam technology, or remain at early stages of development so that their technical feasibility, economic feasibility, and industry-wide commercial deployment is uncertain and may not occur until the 2030s or later. As noted, companies typically target only new production facilities for these proposed innovations.

4.1 Zero-steam technologies

The oilsands industry has been experimenting with zero-steam recovery methods for more than 20 years, though none of these methods have yet proven to be commercially viable from an investment perspective.

There is, in theory, a large potential for decreasing cost and GHG emissions by eliminating the need for steam. Gas combustion, primarily used in steam generation, makes up 75–95% of in situ upstream emissions. Eliminating water from in situ operations would also significantly reduce the need for surface water treatment processing facilities. Two technologies that could potentially have much lower upstream emissions than SAGD, the dominant in situ method, are summarized in Table 3.

Table 3. Zero-steam technologies for in situ production

Company	Technology	Per-barrel emissions reduction potential	Technology readiness level
Acceleware Ltd.	RF XL	50–100%	6
N-Solv	N-Solv	90%	8

The RF XL technology uses electromagnetic energy to generate heat, which converts the water already existing within the oilsands reservoir to steam. This has the potential to eliminate upstream production emissions if the power used is from a zero-emission source. A pilot to prove the technology is planned for late 2021.

The N-Solv technology dilutes the bitumen in the reservoir using pure solvent instead of steam, then recovers the solvent at the surface. A pilot was conducted by the N-Solv Corporation between 2014 and 2017. Results remain confidential but N-Solv no longer appears on oilsands companies' plans, which suggests technical or cost barriers for large-scale commercial deployment.

Despite substantial potential per-barrel emissions reductions, it is important to note that these zero-steam technologies can only be used cost-effectively in new in situ fields; existing fields would have high retrofit costs. They will likely not be deployed unless the economics improve. There are also technical challenges associated with efficiently operating them on a commercial scale that have not been tested.

4.2 Small modular nuclear reactors

Small modular nuclear reactors (also referred to as small modular reactors (SMRs) are a class of fission reactors similar to those used in nuclear power plants but built at a smaller size.[70] SMRs can provide a non-emitting alternative to the combustion of natural gas to generate steam for oilsands. The timeline of the deployment of SMRs in oilsands will depend on the maturity and deployment cost of the applicable reactor technology that is used — some technologies will not be ready for operation until the 2030s while others may be in operation before 2030.[71] SMRs also face several safety, regulatory, and social acceptance barriers that need to be addressed in order to deploy this technology in ways that align with Canada's 2030 targets and 2050 net-zero goal. This section provides an overview of these challenges that need be addressed based on preliminary research completed to date.

According to the classification adopted by the International Atomic Energy Agency, SMRs are nuclear reactors with an equivalent electric power generation capacity of less than about 300 MW_e, with some being as small as 5 MW_e. SMRs can deliver electricity,

[70] As per Alberta Innovates, "the term 'modular' in the context of SMNRs refers to the ability to fabricate major components of the nuclear steam supply system in a factory environment and to deliver and assemble these components at a site in modules. This method of modular construction contrasts with that historically used for the construction of large baseload nuclear power plants wherein much of the plant requires on-site, custom-built construction." Alberta Innovates, *Deployability of Small Modular Nuclear Reactors for Alberta Applications* (2016). https://albertainnovates.ca/wp-content/uploads/2020/07/Pacific-Northwest-National-Labratory-Deployability-of-Small-Modular-Nuclear-Reactors-for-Alberta-Applications.pdf

[71] Daniel T. Ingersoll and Mario D Carelli, editors, *Handbook of Small Modular Nuclear Reactors* (Woodhead Publishing, 2020).

steam, or a mix of the two (co-generation), and since nuclear reactors generate energy through fission (the process of splitting uranium atoms), they do not produce any carbon emissions at the point of use. This technology has been used for decades by universities for research, and in the marine sector to propel vessels.[72]

A 2018 working group has identified that SMRs could play a critical role in meeting Canada's carbon emissions targets by providing non-emitting heat and power to oilsands operations, remote communities, heavy industry and off-grid mines.[73] In most industrial applications, SMRs would in theory replace natural gas to provide zero-carbon heat (e.g. steam) and/or on-site electricity.

The term SMR includes a large number of nuclear-based technologies. Alberta Innovates identified and reviewed 26 nuclear reactor designs, organized into seven reactor types, that could be applied to the oilsands sector.[74] In a subsequent report, they selected two types of SMR technology based on technology readiness level and commercial readiness to be deployed by 2030, as well as on capability to provide electricity, heat, and hydrogen for the oilsands sector. They then provided a techno-economic assessment for each application.[75,76]

The two technologies, integral pressurized water reactors (iPWRs) and high temperature gas-cooled reactors (HTGRs), have existing projects with TRLs over 5, though they have yet to be tested on an industrial scale. As potentially deployed in the oilsands, findings varied:

- **Mining and extraction** — iPWR technology is deemed the best type of SMR to produce both electricity and the medium/low-pressure process steam required by mining and extraction facilities.
- **In situ** — HTGRs are best placed to produce steam and electricity required for SAGD and carbon capture, utilization and storage.

[72] Canadian Small Modular Reactor Roadmap Steering Committee, *A Call to Action: A Canadian Roadmap for Small Modular Reactors* (2018). https://smrroadmap.ca

[73] *A Canadian Roadmap for Small Modular Reactors,* 31.

[74] *Deployability of Small Modular Nuclear Reactors for Alberta Applications* (2016).

[75] Alberta Innovates, *Deployability of Small Modular Nuclear Reactors for Alberta Applications – Phase II* (2018). https://albertainnovates.ca/wp-content/uploads/2020/07/Pacific-Northwest-National-Laboratory-Deployability-of-Small-Modular-Nuclear-Reactors-for-Alberta-Applications-Phase-2.pdf

[76] Other SMNR technologies currently under active development could have application in the oilsands sector, but they were not covered in this report since they are unlikely to be commercially deployable by 2030. Such technologies, reviewed in Alberta Innovates' 2016 report, include sodium fast reactors, molten salt reactors, gas-cooled fast reactors, and heavy liquid metal-cooled fast reactors.

- **Hydrogen production** — Hydrogen is a critical feedstock produced and used by upgraders and refineries. Both iPWR and HTGR technologies can be used to generate zero-carbon electricity (possibly in addition to heat) that can be fed to an electrolyzer to produce hydrogen.

Table 4. Summary of SMR decarbonization potential in oilsands

Small modular nuclear reactor type	Application			TRL
	Mining and Extraction: Hot water, electricity, and process heat	In situ: High-pressure steam injected to reservoirs	Upgrading: Steam methane reforming to produce hydrogen	
Integral pressurized water reactor (iPWR)	✓		✓	5–7
High temperature gas-cooled reactor (HTGR)		✓	✓	5–8

When referring to SMRs, the key is to define the type and maturity of the reactor type that best fits the application. While some water-cooled reactors may be operational outside Canada prior to 2030, Generation-IV reactors (i.e reactors using liquid metal and molten salt) will likely not be ready until after 2030 based on how fast these technologies can be de-risked to be safe, reliable and cost effective compared to other more established technologies such as renewables with storage and geothermal.

4.2.1 Challenges and uncertainties of SMRs

Nuclear technologies have unique risks, costs and uncertainties that can reduce the possibility of deployment at scale in the oilsands in the timeframes required to meet 2030 emissions goals. They can be summarized as:

1. **Higher costs:** SMRs are materially more expensive than the proven gas-fired methods they would replace. Based on early cost estimates, iPWR and HTGR technologies are 46% and 78% more costly than natural gas cogeneration on a levelized cost of energy basis and ~3.5 to 4 times higher capital cost than natural gas co-generation.[77] Most emissions will come from existing steam generation

[77] To do this comparison, Alberta Innovates' analysis uses the levelized cost of electricity as a proxy. The capital costs of iPWRs and HTGRs were estimated at $69 and $79/MWh, compared to $20/MWh for natural gas cogeneration.

facilities, but the cost of retrofitting SMR within existing facilities will be greater than building stand-alone SMRs.

2. **Timeline for development remains uncertain:** Given the urgency to meet interim emissions targets in 2030, the timelines for development followed by deployment remain unclear, and are dependent on the reactor technologies used Nuclear and oilsands facilities have very different safety, regulatory and security requirements which makes planning for a project more difficult and potentially more time-consuming.
3. **Radioactive nuclear fuel waste:** SMR facilities also face the challenge of near-permanent storage and security for the spent nuclear fuel. Radioactive waste is first stored on site for about 10 years while the spent fuel cools, and then it transferred offsite presumably for centralized spent nuclear fuel management.
4. **Social acceptability:** Given the legacy of nuclear weapons and historical accidents at nuclear plants, there may be varying degrees of public acceptance of nuclear technologies in Alberta. This may not be the case for other provinces with historically established nuclear plants.

Further research is needed to better understand the technical and economic viability opportunities for various SMR technologies in the oilsands, the risks associated and the potential mitigation pathways

5. Carbon capture, utilization and storage

Carbon capture, utilization and storage (CCUS) is a combination of several technologies that include the processes of capturing CO_2 from combustion streams, purifying, compressing, transporting, then using the CO_2 or injecting the gas into subsurface geological formations where it can be permanently sequestered and monitored.[78] CCUS technologies continue to evolve and include a wide range of sub-types from early research to commercially deployed and operational.[79] Nearly all scenarios showing a pathway to 1.5–2°C warming targets include a combination of point source CCUS and techniques to remove emissions from the atmosphere (negative emissions) to reduce emissions in hard-to-abate sectors.[80] Therefore, it is important to distinguish where CCUS can and cannot be used to decarbonize oilsands emissions in the context of a full economy net-zero plan.

Several factors can contribute to faster acceleration of CCUS deployment. These include certainty around increasing carbon pricing, declining technology costs, and synergies between different sites that can reduce the unit cost by increasing scale or using common infrastructure. Historically, the de-risking of CCUS projects in Canada has been made possible through public subsidies. Table 5 lists the three large scale CCUS projects that have been successfully operating.

[78] For storage to be considered permanent, a measurement, monitoring and verification plan needs to also be in place to ensure gas is not leaking back to the surface after injection.

[79] The most mature method of CCS is liquid solvent, with TRL of 9, while other methods have different ranges. A detailed review CCS technologies can be found in Global CCS Institute, *Technology Readiness and Costs of CCS* (2021). https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf

[80] International Energy Agency, *Comparison of use of CCUS in the IPCC scenarios and the NZE in 2050* (2021). https://www.iea.org/data-and-statistics/charts/comparison-of-use-of-ccus-in-the-ipcc-scenarios-and-the-nze-in-2050

Not all CCUS in oilsands is the same

A few fundamental factors impact how easy, and expensive, it is to remove a tonne of CO_2 from a given process. These include the concentration of CO_2 in each stream, the size of the overall stream, and the distance between the captured CO_2 and the final sequestration or use site. A common metric to describe the net impact of these factors is the **levelized cost of net CO_2 permanently removed** on a $/tonne basis.

Within oilsands, we can divide the use of CCUS into two main streams based on the factor that has the largest impact on capture cost: the concentration of CO_2 in the target streams. The graphic below shows the two types. With high-CO_2 streams in hydrogen plants within upgrading sites, we estimate CCUS can remove up to 7 MT CO_2e annually using deployable and proven technologies. The challenge will be on accelerating investments in low-concentration CO_2 for in situ plants. While several pilots are on the go, no large-scale project has been announced.

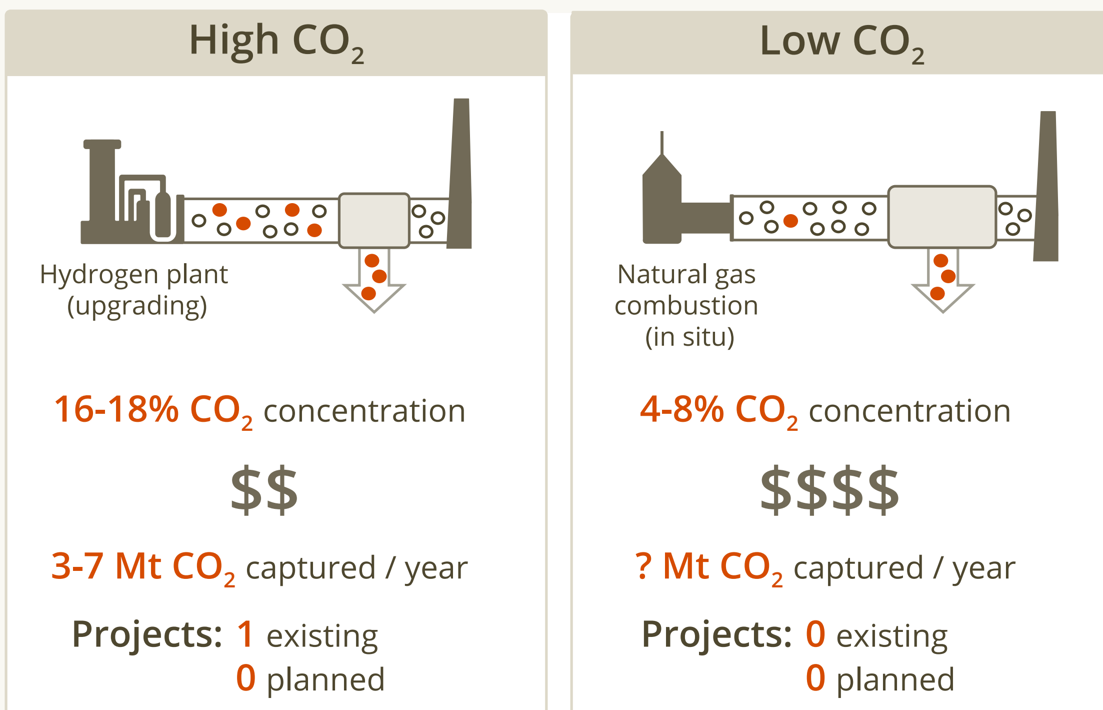

Table 5. Government funding for large-scale CCUS projects in Canada [81]

[81] Alireza Talaei, Jason Switzer, Sara Hastings-Simon, Brian Mellor *The CarbonTech innovation system in Canada,* Table 3 (2020). https://www.pembina.org/reports/carbontech-innovation-system.pdf

Project	Total cost ($M)	Federal funding ($M)	Provincial funding ($M)	Share of government funding in total project costs
Alberta Carbon Trunk Line	1,200	63	495	46%
Shell Quest[82]	1,310	120	745	66%
Boundary Dam	1,350	240	1,110	100%
Total		**423**	**2,350**	

Of this list, only one facility captures CO_2 associated with oilsands emissions. That is Quest, a carbon capture and storage facility added to the hydrogen plant in the Scotford Upgrader near Fort Saskatchewan, Alberta. Since it started operations in 2015, Quest has net stored approximately 1.0 Mt CO_2 annually. While this number is small (reducing oilsands emissions from 84 to 83 Mt in 2019), Alberta has some attributes that could enable CCUS to be scaled up in oilsands, including a well-studied geology suitable for CO_2 storage; the engineering expertise to build commercial-scale projects; a rising carbon price; and the experience required to develop a regulatory framework that ensures sequestration is well-monitored and permanent.

In June 2020, the Alberta Carbon Trunk Line (ACTL) system[83] was inaugurated to capture industrial emissions and deliver the CO_2 to mature oil and gas reservoirs for use in enhanced oil recovery and permanent storage. While ACTL currently does not transport any CO_2 captured from oilsands facilities, it has the capacity to transport up to 14.6 Mt of CO_2 per year. As of early 2021, only two industrial projects use the ACTL to transport and sequester their emissions, collectively using about 10–14% of the capacity of the full line (see Table 6).

[82] Shell estimated the cost of capturing and sequestering CO_2 at the Quest project at $80/tonne. Deborah Jaremko, "Quest CCS project reaches big CO_2 storage milestone," *JWN,* May 24, 2019. https://www.jwnenergy.com/article/2019/5/quest-ccs-project-reaches-big-co2-storage-milestone-costs-trending-down/

[83] Alberta Carbon Trunk Line, "The ACTL System." https://actl.ca/actl-project/about-actl/

Table 6. Canadian large-scale commercial CCUS facilities

Project	Company	Captured emissions (Mt CO_2e/yr)	Operation start year	Industry	Storage type
Saskatchewan					
Boundary Dam Carbon Capture and Storage	SaskPower	1.0	2014	Power generation	Enhanced oil recovery
Alberta					
Quest†	Shell/CNRL	1.0	2015	Oilsands upgrading – hydrogen production	Geological sequestration
ACTL with Agrium CO_2 Stream	Agrium/ Enhance Energy	0.3–0.6	2020	Fertilizer production	Enhanced oil recovery
ACTL with Northwest Sturgeon Refinery CO_2 Stream	Northwest Sturgeon Refinery/ Enhance Energy	1.2–1.4	2020	Oil refining	Enhanced oil recovery
Polaris phase 1	Shell	0.75	Mid 2020s	Oil refining hydrogen – production	Geological sequestration
Caroline Carbon Capture	Pieridae Energy	1.0–3.0	Mid 2020s	Power generation, gas processing	Geological sequestration
Nauticol Energy blue methanol	Nautico Energy and Enhance Energy	1.0	Late 2020s	Methanol production	Unknown

Data sources: Global CCS Institute,[84] Alberta Department of Energy

† Quest does not capture flue gas emissions, only syngas, which is ~48% of total. Does not include energy penalty (emissions from energy used in CCUS processes)

In June 2021, when five major oilsands companies announced the Oil Sands Pathways to Net Zero initiative, they indicated an intention to collaborate on another CCUS

[84] Global CCS Institute Facility Database (Accessed February 2022) https://co2re.co/FacilityData

transport pipeline linking oilsands facilities in the Fort McMurray and Cold Lake regions to a sequestration hub near Cold Lake. The first phase of this initiative (between now and 2030) is estimated to capture 8.5 Mt/yr from eight facilities.[85] TC Energy and Pembina Pipeline also announced a plan to jointly re-purpose existing pipelines that can add 20 Mt/yr of CO_2 transport and sequestration potential.[86] The recent announcements did not provide details on specific final investment decisions or timelines.

Importantly, the low utilization of the ACTL shows that emissions reductions are not realized until capture plants have actually been built and begin operating. It is therefore critical to distinguish between announcements for pipelines with a given capacity to transport CO_2 and the amount of CO_2 permanently sequestered.

5.1 Challenges of CCUS

5.1.1 Unknown scale of deployment beyond 2030

CCUS can play an important role in reducing emissions from higher-concentration sources between now and 2030. It is estimated that emissions associated with hydrogen production in oilsands upgrading account for around 31% of upstream upgrading emissions.[87] In 2019, upgrading emissions accounted for about 30% (25 Mt CO_2e) of upstream oilsands emissions. Therefore, CCUS potential in hydrogen production can be estimated to be approximately 7 Mt CO_2e, or about 8% of upstream oilsands emissions.[88] However, once CCUS has been integrated into hydrogen production, the economics and utility of deploying it on lower-concentration streams is less clear, as discussed below.

[85] "Pathways plan to achieve net zero emissions."

[86] Only the northern leg is planned to connect oilsands to a sequestration hub. TC Energy, "Pembina and TC Energy Partner to Create World-Scale Carbon Transportation and Sequestration Solution: The Alberta Carbon Grid," media release, June 17, 2021. https://www.tcenergy.com/announcements/2021/2021-06-17-pembina-and-tc-energy-partner-to-create-world-scale-carbon-transportation-and-sequestration-solution--the-alberta-carbon-grid/

[87] Direct emissions of natural gas for hydrogen, in Table A.31. "Improving robustness of LCA results through stakeholder engagement: A case study of emerging oil sands technologies."

[88] This assumes 90% CO_2 capture rate from direct hydrogen production emissions of 16.8 kg CO_2/ kg CO_2e/bbl SCO. Total upgrading and oilsands emissions are from *NIR-2021* (83 Mt CO_2e for year 2019). Actual CO_2 capture volumes will be different depending on how early CCUS plants start operating.

5.1.2 Higher cost for of low-concentration CCUS

Nearly half of CO_2 emissions (49%) from in situ projects[89] are found in lower concentration post-combustion streams (CO_2 concentrations that range between 4% and 8%). While new technologies are being developed, the currently proven method of capturing CO_2 at lower concentration is more expensive, and economic viability will likely require both a reduction in technology costs and the price of carbon rising to at least $170/t. The sooner CCUS is built, the longer life these projects have, improving their economics, given that steam generation facilities have shorter life than upgraders.[90]

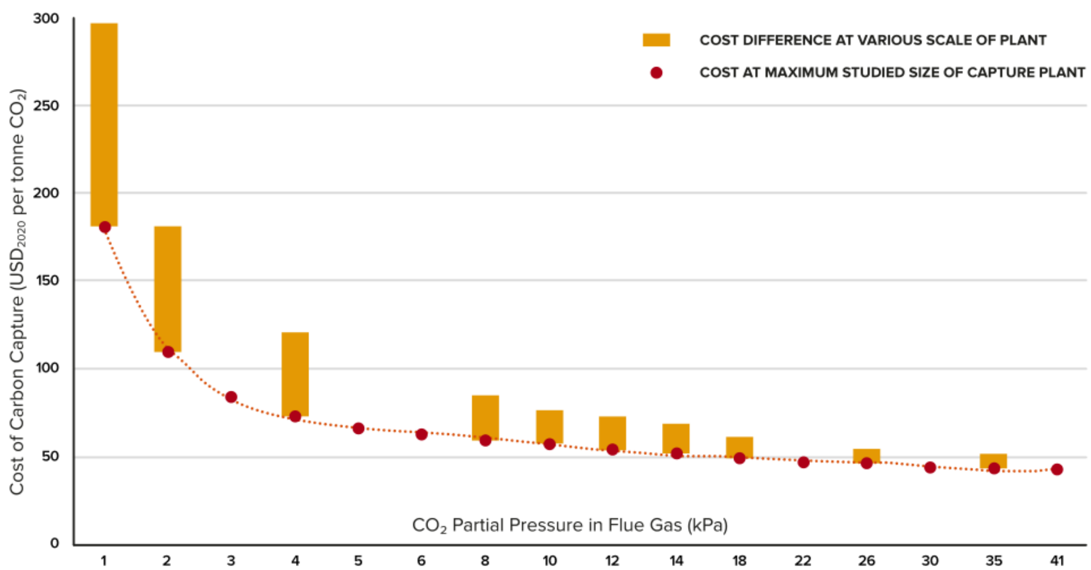

Figure 11. Capture cost ranges for various point-source CO_2 concentrations

Source: Global CCS Institute[91]

Flue gas streams are at atmospheric pressure.[92] The circle marker indicates the cost at the maximum studied size of a single carbon capture plant. Each bar indicates the capture cost ranges from 10% to 100%

[89] In situ combustion and cogeneration from *NIR-2021,* Table A10-3.

[90] A typical steam generation plant has a 30-year design life, and existing plants are expected to start reaching end of life in the 2030s.

[91] *Technology Readiness and Costs of CCS,* Figure 11.

[92] The partial pressure of CO_2 affects the relative ease with which CO_2 can be captured from a gas mixture. Higher partial pressures are easier and cheaper to capture than lower pressures because less external energy is required to increase the CO_2's partial pressure to that in the final captured CO_2 stream. Higher CO_2 partial pressures are observed when the fraction of CO_2 is higher, the overall gas pressure is higher, or both.

5.1.3 Other risks and uncertainties

Deploying CCUS is not just a technical challenge. The industry will have to address issues including public acceptability, and governments will have to develop national and/or regional regulatory frameworks to enable and incent the development of CCUS projects. Such regulations will have to address legal uncertainties such as the ownership of pore space, management of long-term liability, monitoring of CO_2 sequestration, possible environmental impacts of injection, and possible risks posed to human health.

Finally, CCUS projects are complex and require several years from the final investment decision to start of operations. Though the oilsands industry has signalled an intention to build CCUS projects in the current to 2030 period and post 2030, specific project details are still pending.

6. Negative emission technologies and solutions

Negative emissions refer to technologies and solutions that directly remove GHGs from the atmosphere (rather than from a pollution stream, as CCUS does) and store them permanently. This can be achieved through a range of nature-based or mechanical solutions such as direct air capture or nature-based solutions. However, these options are limited and should be prioritized for residual emissions after all efforts have been exhausted to mitigate emissions or develop low-carbon alternatives. These solutions will also be needed to draw down emissions below zero beyond 2050 to ensure continuing climate stabilization, so they should be used sparingly to achieve net-zero upstream emissions for oilsands.

6.1 Direct air capture

Direct air capture (DAC) is the process of capturing CO_2 directly from ambient air (as opposed to capturing from point sources) for permanent sequestration or utilization. While the technology is still in the process of being commercially deployed, direct air capture represents a costly and limited solution for residual and difficult-to-eliminate emissions.[93]

A study carried out in 2019 by Carbon Engineering found a levelized cost of US$94 to US$232 per tonne of captured CO_2 from the atmosphere.[94] Other studies have shown that direct air capture costs could potentially decline depending on how quickly projects advance, and on decreasing energy input costs.[95] The energy required to run direct air capture is also very high, and so deployment will depend on ample supply of low-cost and very low- to zero-emissions intensity electricity.

Given direct air capture will likely be required to reach global net-zero emissions by 2050 and will expand beyond that date, the limited offsets using direct air capture

[93] While some DAC technologies can be used to generate zero-emissions liquid fuel, we discuss DAC here as a way to offset other emissions.

[94] David W. Keith, Geoffrey Holmes, David St. Angelo, Kenton Heidel, "A Process for Capturing CO_2 from the Atmosphere," *Joule* 2 (2018). https://www.cell.com/joule/pdfExtended/S2542-4351(18)30225-3

[95] Mahdi Fasihi, Olga Efimova, Christian Breyer, "Techno-economic assessment of CO_2 direct air capture plants," *Journal of Cleaner Production* 224 (2019). https://doi.org/10.1016/j.jclepro.2019.03.086

should be prioritized for emissions that are likely to continue beyond 2050 and not as a replacement for direct emission reduction efforts for oilsands operations.

6.2 Nature-based solutions

Nature-based solutions (NBS) are the purposeful management of natural systems to reduce climate impact and protect biodiversity[96] by using natural assets to produce tangible climate benefits. Typically, NBS projects are broken into two categories: mitigation and adaptation. In mitigation, ecosystems are managed, conserved, or restored to enhance their ability to sequester carbon.[97] Nature-based adaptation focuses on preserving and restoring ecosystems and natural infrastructure to reduce the future impact of climate-related damage. For example, natural assets like trees and shrubs can be used to protect against flood damage or aid in urban cooling during summer months.[98]

A study specific to Canada found that with better management, further restoration and conservation, nature-based solutions can reduce greenhouse gas emissions by up to 78 Mt annually in 2030.[99] The same study found that within Canada, better land management can offer the most immediate carbon reduction. Restoration of natural landscapes provides few carbon benefits now but could play a larger role in mitigation as we look to 2050. In the meantime, there is mounting evidence that they can play a significant role in adaptation and resilience.

Commitments to nature-based solutions in Canada are outlined in Table 7.

[96] CPAWS, *Finding Common Ground: Six Steps for Tackling Climate Change and Biodiversity Loss in Canada* (2019), 5. https://cpaws.org/wp-content/uploads/2018/02/4.1-CPAWS_FindingCommonGrd_report_v10.pdf

[97] German Federal Agency for Nature Conservation, *Nature-Based Approaches for Climate Change Mitigation and Adaptation* (2014), prepared by EcoLogic, 4. https://www.ecologic.eu/sites/files/publication/2014/eco_bfn_nature-based-solutions_sept2014_en.pdf

[98] *Nature-Based Approaches for Climate Change Mitigation and Adaptation,* 4.

[99] Nature United, “Natural Climate Solutions,” 2021. https://www.natureunited.ca/what-we-do/our-priorities/innovating-for-climate-change/natural-climate-solutions/

Table 7. Examples of nature-based solutions in Canada

Company/Institution	Milestone	Year
Federal government	$3 billion announced for nature-based solutions	2019
Federal government	Land disturbance included in National Inventory Report	2020
Cenovus	2030 target of reclaiming 1500 decommissioned well sites and completing $40 million of caribou habitat restoration	2020
BP	Intention to leverage nature-based solutions in tandem with CCUS to achieve net-zero targets	2020
Shell	Intention to leverage nature-based solutions to meet 2050 net-zero targets	2020

Canadian and international energy companies are increasingly interested in nature-based solutions as an investment to decrease net carbon emissions. One of the most common mechanisms discussed within the industry is developing NBS projects to generate carbon offsets. However, there are many issues with using nature-based offsets given the lack of standards that differentiate between high-quality and poor-quality projects.

Requirements for effective nature-based solutions[100,101]

- Reductions are **additional** beyond what was already planned to occur in the absence of any financial incentive from the offset. Best practice is to establish conservative baselines in order to measure improvement.
- Emissions reductions must be **permanent** over the life of the project. Risks of the carbon sink being reversed or destroyed are managed.
- Solutions are **independently verified** by credible third parties.
- Solutions are **integrated** into larger policy framework.

[100] Nature-Based Climate Solutions Summit, *Carbon Offsets Breakout Session*, (2020), 2. https://static1.squarespace.com/static/5dee67fbbfc3d2411199251b/t/5e87dbcad6d6f128a16f4309/1585961935889/Carbon+Offsets+Breakout+Session.pdf

[101] Smart Prosperity Institute, *Nature-Based Solutions: Policy Options for Climate and Biodiversity* (2020), 9. https://institute.smartprosperity.ca/sites/default/files/nbsreport.pdf

- The risk that carbon sequestration in one area could lead to an increase in carbon emissions in another is avoided or managed (**no leakage**).
- **Conservation biodiversity and local community considerations** are incorporated into development and implementation, specifically for species-at-risk, animal migration areas, natural corridors and local economic sustainability

The accounting and measurement rules used in offsetting emissions with nature-based projects can be questionable. For example, a forest area can be overvalued by claiming it will be protected when there were never plans to cut it down. Even when areas are restored, there is a need for more robust accounting or insurance system that ensures the durability and safeguarding of the carbon benefits against risks such as forest fires. Efforts to evolve the integrity, quality, proof standards for voluntary carbon markets are underway, therefore what counts as effective nature-based offsets will also evolve to meet these rising standards.

Carbon offsets from nature-based solutions need to be utilized carefully after all efforts to reduce direct emissions have been exhausted across all sectors of the economy. The full potential for nature-based solutions in Canada is limited, representing 11% of the country's 2019 emissions.[102] Therefore, offset options must be applied strategically to the last portion of residual national emissions where we currently don't have technologies ready for deployment at scale, such as emissions from agricultural crop production or from aviation and marine transportation. Upstream oilsands emissions are relatively more concentrated and can be reduced at lower cost and more efficiently with other pathways.

[102] Nature United, "Natural Climate Solutions."

7. Non-combustion uses

Emissions from end uses of oilsands crude (such as burning gasoline by a car) are accounted for in the sectors and regions where the refined product is used. A new line of innovation explores new end uses of bitumen as feedstock to produce high-value materials,[103] sometimes called bitumen beyond combustion. While this report is focused almost entirely on the upstream (Scope 1 and 2) emissions from oilsands production and technologies available to reduce them, non-combustion end uses present another strategic economic opportunity for oilsands in a world transitioning to net-zero. The primary emissions benefit of using bitumen for non-combustion uses is the elimination of Scope 3 or end-use emissions. In non-combustion uses, the emissions intensity of the product will depend on upstream emissions which further underscores the need to reduce and eliminate these emissions.

Bitumen has higher carbon content than is typically found in lighter crudes which results in higher emissions intensity. This higher carbon content can present a competitive advantage when considering the type of materials that can be produced from bitumen. For example, materials such as asphalt binder[104] and carbon fibre are used for many high-value products (Table 8).

There are several key factors to consider when evaluating the potential impact of non-combustion uses for bitumen. The range of materials that can theoretically be produced from bitumen can be ranked based on GHG reduction potential and maximum economic value. Table 8 describes products ranked by the percent of the bitumen barrel used.

---

[103] John Zhou, Paolo Bomben, Murray Gray, Bryan Helfenbaum, *Bitumen Beyond Combustion: How oil sands can help the world reach net-zero emissions and create economic opportunities for Alberta and Canada* (Alberta Innovates, 2021). https://albertainnovates.ca/wp-content/uploads/2021/11/AI-BBC-WHITE-PAPER__WEB.pdf

[104] Asphalt binder is a critical component that is added to other solids to make final materials for roads, roofing, water proofing.

Table 8. Summary of alternative uses for bitumen

Material	Product value ($/kg)	Portion of barrel used	Uses	Examples of end-use emissions reduction
Asphalt binder	0.65	40–50%	Roads, waterproofing and sealant materials	Longer life products that require less replacement and net GHG reduction over life of product
Activated carbon	2	15–30%	Water purification, gas treatment, metals recovery, supercapacitors	Supercapacitors and batteries enable more efficient, low-cost energy storage devices
Carbon fibre	12.5	15–20%	High-end products where strength, durability and low weight is required (e.g. aircraft)	Blended with polymers to make composite wind turbine blades, used to make lighter vehicles, and can be used to reduce use of concrete in buildings.

Data source: Alberta Innovates[105]

In the case of asphalt binder, the remaining portion of the barrel (de-asphalted barrel) would still be refined into fuels for traditional refined products. However, the lighter product would flow more easily through pipelines and as a result require less diluent for transport, while it would also fetch a higher price than diluted bitumen.

As research into non-combustion uses of bitumen is relatively new, a full life cycle analysis is much needed to compare different methods of producing these materials from various types of hydrocarbons to quantify the true impact on emissions across each step in the value chain.

The GHG reduction will be realized at end use. For materials that are exported, this may not directly reduce Canada's GHG emissions, but will contribute to global GHG reductions. In fact, there is a possibility that producing materials from bitumen could increase Alberta's GHG emissions depending on the energy intensity of the manufacturing process. This further underscores the need for robust life cycle analysis.

[105] John Zhou, Paolo Bomben, Murray Gray, Bryan Helfenbaum, *Bitumen Beyond Combustion: How oil sands can help the world reach net-zero emissions and create economic opportunities for Alberta and Canada* (Alberta Innovates, 2021). https://albertainnovates.ca/wp-content/uploads/2021/11/AI-BBC-WHITE-PAPER__WEB.pdf

Non-combustion uses of bitumen present a long-term strategic economic opportunity that is compatible with lower oil demand scenarios. This line of research remains at the early stage of development. Provincial and federal governments have critical roles to play to accelerate this line of research to unlock new economic opportunities.

8. Conclusion

For Canada to be on track to meet its global commitment to net-zero GHG emissions by 2050, all sectors of the economy must decarbonize to contribute to a minimum of a 40–45% reduction in emissions over 2005 levels by 2030. Given that the steepest increase in carbon emissions since 2005 has been from oil and gas, there is an argument that the sector should decline at a higher rate relative to other sectors. This argument is backed up by current opportunities in the oil and gas sector to reduce emissions at an accelerated rate compared to other sectors that may not be able to achieve 40–45% reductions by 2030.

Since 2005, oil and gas emissions have increased by 20%, including oilsands by 137%. Emissions from transport have increased by 16% and buildings by 8%. All other sectors' emissions have declined since 2005, including the electricity sector by 48%. Taken together, by 2019 GHG emissions had only dropped 1% below 2005 levels in Canada.[106]

Progress in reducing GHG emissions in sectors such as electricity has been offset by rising emissions from the oil and gas industry and the consumption of oil products for transportation and gas products for heating. Progress made by producers to reduce per barrel emissions intensity has been eclipsed by increased absolute emissions due to growth in production.

The federal government has recently announced plans to cap and set a declining trajectory for oil and gas emissions. The oilsands represent a rising share of Canada's oil and gas emissions in (43% in 2019), and historic and projected emissions from the sector need to be reconciled with Canada's climate goals.[107] The Oil Sands Pathways to Net Zero initiative presents a vision for how the oilsands could achieve net-zero emissions by 2050. It assumes that to achieve net-zero, participating companies will rely to a large extent on strategies that will not be technically or economically viable until after 2030.

To be credible, the vision document that has been put forward by oilsands companies should be accompanied by a detailed plan and aligned with Canada's commitment to achieve an economy wide 40–45% emission reduction by 2030.

[106] *NIR-2021*.

[107] The 2020 official projection from ECCC is that oilsands emissions will go up from 83 in 2019 to 95 Mt CO_2e in 2030.

Technology challenges

Globally, reaching net-zero requires significantly lower crude oil demand. Those reductions will be driven in large part by jurisdictions like the United States, Canada, and Europe as they transition to a net-zero electrical grid and from fossil fuel powered cars to electric vehicles by 2035 or earlier. As global demand declines, oil producers will compete in a shrinking market, likely leading to lower crude prices. Meanwhile, high-emissions producers will face increased cost associated with reducing pollution.

Technology options that can decarbonize some oilsands emissions currently exist while others are years away from commercial deployment. Oilsands decarbonization technologies can be classified into five categories (see Table 9 for summary):

1. Current technologies — fuel switching, energy efficiency, steam displacement
2. Future technologies — zero-steam in situ, small modular reactors (SMRs)
3. Carbon capture, utilization and storage
    - from higher CO_2 concentration sources such as hydrogen production
    - from lower CO_2 concentration sources such as steam boilers and co-generation plants for SAGD
4. Negative emissions — direct air capture and nature-based solutions
5. Using bitumen to produce valuable non-combusted materials

This report suggests that most of the low-cost emissions reduction potential of current technologies has largely been realized. According to a 2020 IHS study, upstream emissions intensity between 2009 and 2018 decreased by 1% for SAGD and 24% for mining, while increasing by 18% for cyclic steam stimulation.[108] Additional improvements are possible but will require a shift in capital allocation to primarily lower emissions.

The impact of future technologies remains uncertain. They remain not ready for commercial deployment. A set of complex factors can impact their potential deployment such as technology costs, level and scope of carbon pricing, and how investors view the long-term trajectory of oil demand post 2030 when these technologies can be technically ready for full-scale deployment.

Carbon capture on higher concentrated streams of CO_2, such as hydrogen plants in upgraders, is the most promising opportunity area. It is likely to spur future investment

[108] These numbers are for upstream life cycle including electrical import/export, upstream natural gas production and upstream diluent. IHS Markit, *The GHG intensity of Canadian oil sands production: A new analysis,* Tables A2 to A-4A.

in response to an increasing carbon price, especially if a targeted investment tax credit is implemented for the technology. Though significant, we estimate that full deployment of CCUS in all high-concentration streams could result in a decrease of approximately 7 Mt CO_2e annually, which equates to 8% of total oilsands emissions. [109]

It is technically possible to capture CO_2 from low-concentration sources such as the exhaust stacks from large gas-fired turbines, boilers or heaters. However, the cost to retrofit these distributed sources needs to be taken into account, especially as in situ steam generation plants have shorter remaining life compared to refineries. In situ operations are more distributed, resulting in high compression and transportation costs. CCUS is also an energy-intensive process. Zero- or low-emissions energy needs to be prioritized to lower the GHG emissions penalty that comes from using natural gas to power CCUS. Overall, capturing CO_2 from low-concentration sources could result in an increase in operating costs.

Negative emissions strategies are limited by high cost, in the case of direct air capture, or a lack of validation and verification mechanisms in nature-based solutions.

Non-combustion uses of bitumen present a long-term strategic economic opportunity compatible with lower oil demand scenarios but will still require decarbonization of upstream bitumen production to lower the life cycle emissions intensity of new high-value materials

Oilsands in a net-zero world

Lower-cost oilsands operations could continue to produce oil for transport fuels even as demand declines. This will require companies to make investments in decarbonization to comply with the Canadian clean fuel regulation, to avoid rising carbon prices, and to avoid new domestic or international regulatory or trade measures designed to discourage the use of high-carbon sources of oil over the coming years. Higher-cost oil operations that will not be able to compete will shut down, resulting in lowering both production and emissions from the sector.

A Canadian 1.5°C-compatible net-zero pathway for the oil sector could, over the longer term, see continued but limited production of net-zero oil to provide feedstock for plastics and other products. Under this scenario, remaining net-zero Canadian oil production will have to compete with other lower-cost oil to continue past 2050.

[109] This assuming CCUS with 90% capture rate is used in all hydrogen production plants in upgraders. Emissions level is based on 2019 baseline.

A declining cap on oil and gas emissions, like the one currently being pursued by the federal government, effectively represents a predictable target. Depending on how it is implemented, it can support investment decision-making and lower the risk of stranded assets. An emissions cap on the oil and gas sector as a whole has the potential to provide producers with different options to comply with the new regulation in ways that can accelerate reductions between now and 2030. This is because Canada has multiple low-cost emission reduction opportunities that are already technically and economically achievable in the upstream oil and gas industry. If, for example, the cap policy allows companies with high abatement costs to acquire emission reduction credits from companies with low abatement costs, then oilsands companies could both invest in direct emission reduction projects within the oilsands and buy credits from projects within the oil and gas sector to achieve their overall target.

In the long run and notwithstanding volatility in energy demand and supply, the world cannot address climate change without significantly lower demand and production of crude oil. To manage the risk of stranded assets during this transition any credible pathway for emissions reduction in Canada's oilsands needs to include the assumption that demand decline for oil will translate into production decline in that sector.

In the short run, an emissions reduction strategy for oilsands that sees a 22 Mt CO_2e reduction in absolute emissions reductions by 2030 — and assumes more substantial progress on emissions reduction will not occur for another decade or more — will not put oilsands producers on a credible pathway to their own, or Canada's, net-zero target for 2050. Multiple pathways for emissions reduction will need to be pursued.

Along with other regulations and incentives, a cap on oil and gas emissions will drive oilsands companies to achieve emission reduction opportunities that currently exist in their sector. It may also provide access to compliance options that will accelerate technically and economically achievable reductions in other parts of the oil and gas sector. This would put the sector on a pathway aligned with Canada's 2030 target.

The impending release by the federal government of a 2030 Emissions Reduction Plan for Canada represents a critical juncture for more rigorous review and collaboration among governments (federal, provincial, municipal, Indigenous) and with industry and stakeholders on the challenges and opportunities for emissions reduction in Canada's oilsands and oil and gas sector as a whole.

Appendix A. Summary of technology and solutions to decarbonize the oilsands

Table 9. Summary of technology and solutions to decarbonize the oilsands

Technology / solution	Application			Applicable in existing wells and facilities	2030 reduction potential*	TRL	Cost
	Mining	In situ	Upgrading				
Current technologies							
Fuel switching	✓	✓	✓	✓	1–2 Mt CO_2e <2.4%	9	$$
Energy efficiency	✔	✔	✔	✓	~0.5–2 Mt CO_2e <1.2%	9	$
Steam displacement	✔			✓	<5–10% [a]	5–9	$$
Future technologies							
Zero-steam		✓			0–15% [b]	5–8	?
Small modular nuclear reactors	✓	✔	✓	✓	?	5–8	$$$$
Non-combustion uses	✓	✓		✓	?	2–3	?
Carbon capture							
Carbon capture and storage [c]		✓	✔	✓	<7 Mt CO_2e (~8%)	8–9	$$$
Emerging, low CO_2 concentration carbon capture	✓	✓	✓	✓	?		
Negative emissions							
Direct air capture	✓	✓	✓		?	5–7	$$$$
Nature-based solutions	✓	✓	✓		?	5–8	$ to $$$[d]

Legend: ✓ Applies to some emissions ✔ Applies to majority of emissions

? Costs and impact have great uncertainty or are unavailable

* This represents the potential by 2030 based on historical investment trend. Lower technology cost and more intentional investment driven by higher carbon price can yield higher potential.

a) Assumes most steam displacement only applies to in situ, and only where economically viable.

b) Outcomes are uncertain; zero-steam solutions might be implemented in anywhere from zero wells to majority of new wells between 2025–2030

c) Assumes commercially proven liquid ammonia absorbent applied to hydrogen production in upgrading. Emerging technologies in pilot stages hold additional potential beyond 2030 but are not included.

d) Cost can be up to $100 per tonne CO_2e within Canada

Appendix B. Technology readiness levels

Table 10. Technology readiness levels (TRLs)

TRL	Description
1	**Basic principles of concept are observed and reported** Scientific research begins to be translated into applied research and development. Activities might include paper studies of a technology's basic properties.
2	**Technology concept and/or application formulated** Invention begins. Once basic principles are observed, practical applications can be invented. Activities are limited to analytic studies.
3	**Analytical and experimental critical function and/or proof of concept** Active research and development is initiated. This includes analytical studies and/or laboratory studies. Activities might include components that are not yet integrated or representative.
4	**Component and/or validation in a laboratory environment** Basic technological components are integrated to establish that they will work together. Activities include integration of "ad hoc" hardware in the laboratory.
5	**Component and/or validation in a simulated environment** The basic technological components are integrated for testing in a simulated environment. Activities include laboratory integration of components.
6	**System/subsystem model or prototype demonstration in a simulated environment** A model or prototype that represents a near desired configuration. Activities include testing in a simulated operational environment or laboratory.
7	**Prototype ready for demonstration in an appropriate operational environment** Prototype at planned operational level and is ready for demonstration in an operational environment. Activities include prototype field testing.
8	**Actual technology completed and qualified through tests and demonstrations** Technology has been proven to work in its final form and under expected conditions. Activities include developmental testing and evaluation of whether it will meet operational requirements.
9	**Actual technology proven through successful deployment in an operational setting** Actual application of the technology in its final form and under real-life conditions, such as those encountered in operational tests and evaluations. Activities include using the innovation under operational conditions.

Source: Innovation Canada[110]

[110] Innovation Canada, "Technology readiness levels.". https://www.ic.gc.ca/eic/site/080.nsf/eng/00002.html