February 2021

Canada's Carbon Tax Hike and Strategic Implications for Oil & Gas Firms

1. Introduction

Canada has been a vocal adopter of the 2015 Paris Climate Agreement, pushing aggressively for the allowable temperature increase to be limited to 1.5 °C, rather than the 2 °C sought by most industrialized countries.[1] However, the large-scale extraction of oilsands and natural gas in the country has been a lightning rod for critics who have accused successive governments of being hypocritical. In 2011, the Conservative government of Stephen Harper, despite calling for a North America-wide emissions reduction of 30 per cent from the 2005 level, actually withdrew Canada from its commitments under the Kyoto climate accord.[2] The current Liberal government under Justin Trudeau purchased the Trans Mountain pipeline to ensure it gets built, but has made no secret of its desire for rapid decarbonization. The latter was demonstrated when the government passed the Greenhouse Gas Pollution Pricing Act (GHGPPA) in 2018 to support its commitments under the Paris Agreement.[3] The Act established a carbon tax of C$20/t$CO_2$e, starting in 2019 with an increase of C$10 every year until 2022, when it would be C$50/t$CO_2$e.

In November 2020, Trudeau announced that the carbon tax, originally promised to be capped at 2022 levels, would be hiked by C$15 every year starting in 2023, resulting in a new cap of C$170/t$CO_2$e in 2030.[4] With this move, Canada is expected to reduce emissions from 730 MT in 2005 to 503 MT in 2030, exceeding its commitment under the Paris Agreement.[5] This announcement has been hailed by environmentalists as one of the boldest steps yet in the fight against climate change and global warming. However, there are concerns that it could erode the competitiveness of Canadian firms and wipe out tens of billions of dollars in operating profits. Table 1 shows the expected carbon tax rates from 2020 to 2030.

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[1] Payton, Laura. 2015. 'Canada endorses tougher 1.5-degree limit to global warming', *MacLeans.* 7 December. Accessed 22 December, 2020. https://www.macleans.ca/politics/ottawa/at-cop21-canada-endorses-tougher-1-5-degree-limit-to-global-warming/.
[2] UK Guardian. 2011. 'Canada pulls out of Kyoto Protocol'. 13 December. Accessed 22 December, 2020. https://www.theguardian.com/environment/2011/dec/13/canada-pulls-out-kyoto-protocol.
[3] Canada Justice & Laws. 2018. *Greenhouse Gas Pollution Pricing Act.* Accessed 22 December 2020. https://laws-lois.justice.gc.ca/eng/acts/G-11.55/.
[4] Tasker, John Paul. 2020. 'Ottawa to hike federal carbon tax to $170 a tonne by 2030'. 11 December. Accessed 15 December 2020. https://www.cbc.ca/news/politics/carbon-tax-hike-new-climate-plan-1.5837709.
[5] Ballingall, Alex. 2020. 'Ottawa proposes steep hike for carbon tax to meet greenhouse gas target.' *Toronto Star.* December 11. Accessed 2 January 2021. https://www.thestar.com/politics/federal/2020/12/11/ottawa-proposes-steep-hike-for-carbon-tax-to-meet-greenhouse-gas-target.html.

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Table 1: Carbon tax in Canada, 2020–2030

Year	Carbon Tax under old GHGPPA (C$/t$CO_2$e)	Carbon Tax under new GHGPPA (C$/t$CO_2$e)
2020	30	30
2021	40	40
2022	50	50
2023	50	65
2024	50	80
2025	50	95
2026	50	110
2027	50	125
2028	50	140
2029	50	155
2030	50	170

Source: Government of Canada

This Energy Insight argues that while the carbon tax hike compounds the ongoing challenges of sharply declining capital spending, increased foreign divestment, and tight takeaway space for crude oil in the short term, it is key to assuring the mid- to long-term viability of the Canadian oil and gas industry by forcing firms to invest more aggressively in emissions-reduction technologies. Following a contemporary review of the country's oil and gas industry, the readiness of much-hyped technologies such as carbon capture and storage (CCS) and its enablement of blue hydrogen will be examined. Finally, a strategic assessment of firms' tactics in the face of this new headwind will be provided, building on models developed in previous research.[6] These will be used to provide commentary on Canada's ability to continue being a strong source of non-OPEC oil and gas production in a carbon-constrained world.

2. Carbon taxation in Canada: a primer

The first jurisdiction in North America to establish a price for carbon was the Canadian province of Alberta, home to the energy-intensive oilsands. The Climate Change and Emissions Management Act (CCEMA), enacted in 2003, set a price of C$15/t$CO_2$. Rather than an actual tax, credits could be acquired through a 12 per cent reduction in emissions intensity in a given year, covered through offset projects or directly purchased at the given price. Credits could also be carried over from year to year.[7] In 2007, Quebec also implemented a carbon tax of C$0.01 per litre on companies selling refined petroleum products, with a stated goal of using the funds to pay for carbon-mitigation projects, such as improved public transit.[8] British Columbia joined the Western Climate Initiative (WCI) in 2007, but left after announcing its carbon tax in 2008. Unlike the WCI, which utilizes a cap-and-trade emissions scheme, British Columbia preferred to implement a direct tax. However, the Canadian provinces of Ontario, Quebec, and Nova Scotia joined the WCI (along with California as the only remaining American jurisdiction), although Ontario withdrew in 2018 after a centre–right government won the general election.[9] Most of these provincial programmes – with the exception of British Columbia's – were deemed to be ineffective because they contained too many loopholes, which allowed the assessment

[6] Ihejirika, Nnaziri. 2019. 'The Canadian Oilsands and Strategic Approaches to Profitability.' *Oxford Institute for Energy Studies Energy Insight No. 56*, August.

[7] Carson, Lorne, Paula Olexiuk, and Dana Saric. 2015. 'Upcoming Developments in Alberta's Carbon Emissions Regulations.' *Osler.* 26 June. Accessed 28 December 2020. https://www.osler.com/en/resources/regulations/2015/upcoming-developments-in-alberta-s-carbon-emission.

[8] Canadian Press. 2007. 'Quebec to collect nation's 1st carbon tax.' *CBC News.* 7 June. Accessed 15 December 2020. https://www.cbc.ca/news/canada/montreal/quebec-to-collect-nation-s-1st-carbon-tax-1.684888.

[9] Busch, Chris. 2018. 'Will Ontario's Carbon Market Withdrawal Harm The Western Climate Initiative? No, Says Price Rebound.' *Forbes.* 2 June. Accessed 28 December 2020. https://www.forbes.com/sites/energyinnovation/2018/07/02/will-ontarios-carbon-market-withdrawal-harm-the-western-climate-initiative-price-rebound-says-no/?sh=1412e04f2731.

of levies to be avoided, or the costs were so low that firms had no incentive to pursue emissions-reduction technologies.

At the provincial level, this changed in 2015, when Alberta's newly elected New Democratic Party (NDP) government enacted the Carbon Competitiveness Incentive Regulation (CCIR) to replace the CCEMA.[10] Retaining the credit purchase provision under the CCEMA, the carbon offset price was increased to C$30 per tonne, methane emission reduction targets were introduced and, most significantly, total annual emissions from the oilsands were capped at 100 MT of CO_2. Additionally, funds from the carbon tax were to be deployed in developing emissions-reduction technologies. The regulation also introduced a consumer carbon tax for the first time in Alberta. Most firms in Alberta's oil and gas sector welcomed the introduction of what they considered a well-defined and robust framework as it offered price certainty, an incentive to reduce emissions, and caps on future emissions, without stifling production growth.[11]

The GHGPPA was designed to be introduced in jurisdictions that did not have comparable carbon-pricing mechanisms or where none existed. While the consumer side of the programme was designed to be revenue neutral for the jurisdictions administering it, with taxpayers receiving rebates at least equal to the tax paid, it is intended to drive deep decarbonization in heavy industry. For large emitters, the GHGPPA is known as the Output-Based Pricing (OBP) system. While firms in energy-intensive industries like oilsands and non-renewable power generation will be taxed at the prevailing rate based on absolute emissions, they will receive partial rebates based on comparative performance.

In 2019, a newly elected provincial government in Alberta replaced CCIR with the Technology Innovation and Emissions Reduction (TIER) programme. The major difference is that firms are now compared to their own past performance, rather than against their best-performing peers.[12] Environmentalists criticized TIER as a step back from CCIR, as firms which had made great strides in reducing emissions were likely to be penalized more than firms that were further behind in the decarbonization journey.[13] Despite this wrinkle, the federal government announced that they had accepted TIER as an equivalent to the original OBP, meaning that large emitters would continue to be administered under the former. This makes Alberta a unique jurisdiction in Canada, with the federal backstop applying to consumers and the provincial plan for large emitters deemed robust enough to avoid federal override.

It is important to note that the governments of Ontario, Saskatchewan, and Alberta took the federal government to court after the original GHGPPA was enacted, arguing that it was unconstitutional. While the courts in Ontario and Saskatchewan upheld the GHGPPA, Alberta's Court of Appeal ruled that it was unconstitutional. The case is now before the Supreme Court of Canada. There are precedents to suggest that this court is likely to side with the federal government, despite the broad powers that provinces hold in Canada's confederal style of government.[14] Until that decision is made, provinces continue to be subject to the GHGPPA in the absence of a suitable provincial alternative. Table 2 summarizes the carbon tax scheme for large emitters in oil and gas producing provinces.

[10] Government of Alberta. 2018. 'Carbon Competitiveness Incentive Regulation.' *Government of Alberta*.

[11] Bakx, Kyle. 2019. 'On the world stage, Canadian oil majors promote a carbon tax.' *CBC News.* 13 March. Accessed 10 December 2020. https://www.cbc.ca/news/business/ceraweek-suncor-husky-carbon-tax-1.5053182.

[12] Fletcher, Robson. 2019. 'How Alberta will keep its $30-per-tonne carbon tax but make it easier for some big emitters to avoid paying.' *CBC News.* 29 October. Accessed 28 December 2020. https://www.cbc.ca/news/canada/calgary/alberta-carbon-tax-tier-sger-ccir-large-emitters-1.5339464.

[13] Ibid.

[14] The Editorial Board. 2020. 'The carbon tax is on trial at the Supreme Court'. *The Globe and Mail*. 27 September 2020. https://www.theglobeandmail.com/opinion/editorials/article-the-carbon-tax-is-on-trial-at-the-supreme-court-with-the-trudeau/.

Table 2: Industrial Carbon Pricing for Oil & Gas Producing Provinces

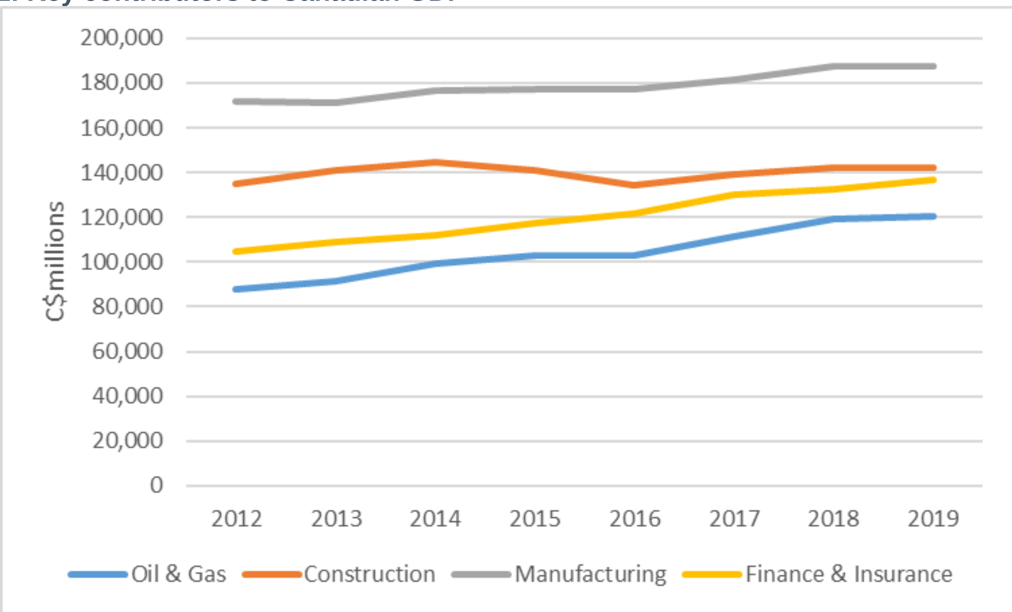
Province	Carbon Pricing Scheme for Industry	2019 Carbon Price ($C\$/tCO_2e$)	Federal Backstop (OBP) Applies
Alberta	Yes	30	No
British Columbia	Yes	40	No
Newfoundland & Labrador	Yes	30	No
Saskatchewan	No	N/A	Yes

Source: Provincial releases

3. The state of Canada's oil & gas industry

The Canadian oil and gas industry had direct contributions of C$120 billion to the Canadian economy in 2019, representing 7 per cent of Canada's total GDP.[15] In addition, the industry contributed billions more, indirectly, through its suppliers. Despite challenges faced by the industry since the oil price collapse in 2015, the oil and gas industry has remained a significant contributor to the Canadian economy as shown in Figure 1 and is Canada's largest source of export revenue. Further, comparison with other major industries in the country demonstrates that oil and gas sector growth has outpaced that of the other major sectors over the past five years.[16] While this resilience is impressive, there are several headwinds that firms have to manage simultaneously. A better understanding of these will be provided by looking at the two major components of the Canadian oil and gas industry – oilsands and natural gas.

Figure 1: Key contributors to Canadian GDP



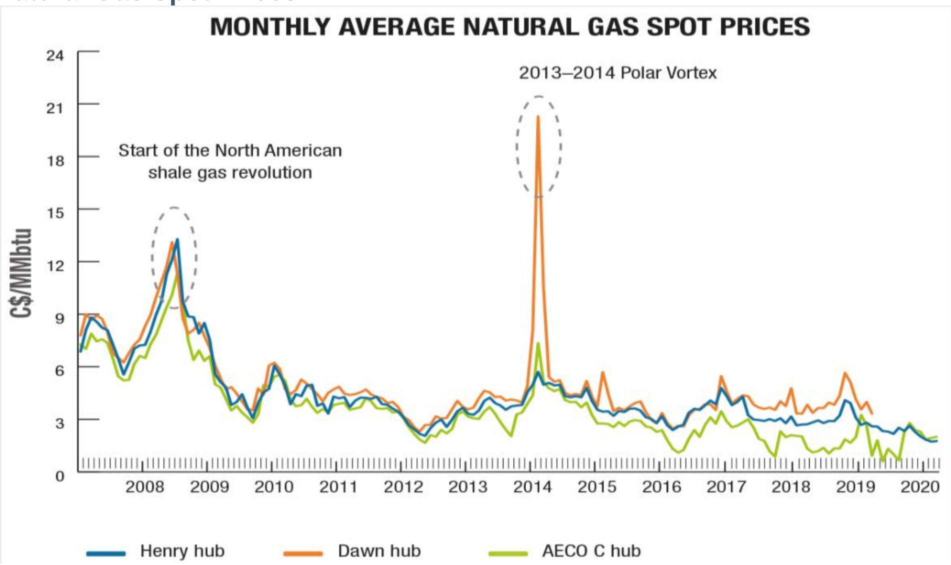
Source: Statistics Canada

[15] Fletcher, Robson. 2018. 'Oil and gas surpasses banking and insurance as share of GDP in May.' *CBC News.* 31 July. Accessed 21 December 2020. https://www.cbc.ca/news/canada/calgary/oil-and-gas-gdp-growth-may-data-statscan-1.4768508.
[16] Statistics Canada. Table 36-10-0434-03 Gross domestic product (GDP) at basic prices, by industry, annual average (x 1,000,000).

Natural gas: an injection of life?

As the fourth largest producer in the world,[17] the natural gas industry in Canada has always been vibrant. At the same time, it is seemingly stuck in survival mode, due to a glut in North American gas production coupled with relatively flat demand.[18] Since June 2008, when the spot price at Henry Hub hit $12.68/MMBtu, the price has steadily fallen and has generally traded below $4/MMBtu since 2015. Figure 2 depicts the trend in natural gas spot prices, displayed in Canadian dollars. Initially, this resulted in significant divestment from the sector, with Suncor Energy selling off their natural gas assets and Encana Corporation splitting into two different entities, Cenovus Energy and Encana Gas Corporation.[19]

Figure 2: Natural Gas Spot Prices



Source: Natural Resources Canada

For the larger players that remained – like Canadian Natural Resources Limited (CNRL) and Husky Energy – natural gas has been deployed into the value chain for the oilsands business. CNRL has referenced the use of its own natural gas in powering cogeneration units at Horizon as a key driver in the company's significant operational cost reductions relative to its peers. While the industry has remained buoyant, concerns about a saturated North American market amidst the shale gas boom led to years of low prices[20], although there was a very modest recovery in Canadian gas prices in 2020. The sector has been somewhat buoyed further by consistent attempts at the provincial levels in particular to push for the development of Liquefied Natural Gas (LNG) projects in Canada, primarily to provide reliable gas exports to Asia and Europe. The first of these major projects is LNG Canada, a joint venture between Shell Canada, Petronas, PetroChina, and Mitsubishi, which has received final sanction and is expected to be commissioned in 2025.[21] There are other projects at various stages of approval, and it is hoped that these will debottleneck the market and provide a sustained boost to received prices. However, further project sanctions are by no means assured, given the level of

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[17] Natural Resources Canada. 2020. 'Natural Gas Facts.' *Government of Canada.* 6 October. Accessed 21 December 2020. https://www.nrcan.gc.ca/science-data/data-analysis/energy-data-analysis/energy-facts/natural-gas-facts/20067#details-panel1.

[18] Bentein, Jim. 2019. 'LNG light at end of tunnel for gas producers.' *Daily Oil Bulletin*, July: 15–17. http://s3.ca-central-1.amazonaws.com/media.jwnenergy/reports/Top100-2019-Report_FINAL.pdf.

[19] Reuters Staff. 2009. 'EnCana wraps up spinoff of its oil business.' *Reuters.* 30 November. Accessed 19 December 2020. https://www.reuters.com/article/encana-cenovus-idUSN3025130420091130.

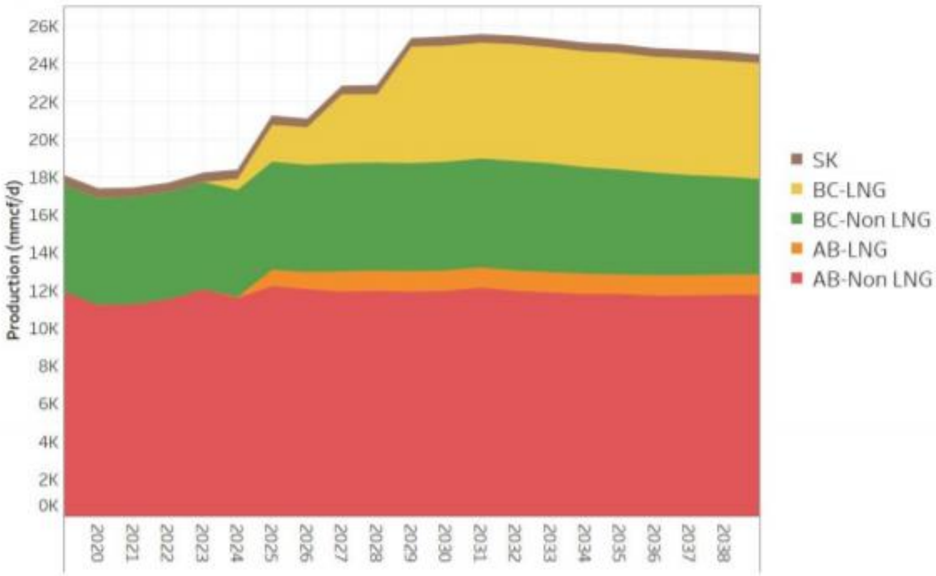
[20] Findlay, J. Peter. 2019. 'Canadian LNG Competitiveness.' *Oxford Institute for Energy Studies*, December 2019.

[21] Hoekstra, Gordon. 2020. '$18-billion LNG project projected to meet mid-decade start despite COVID-19 delays.' 16 November. Accessed 2 January 2021. https://vancouversun.com/business/18-billion-lng-project-projected-to-meet-mid-decade-start-despite-covid-19-delays.

opposition from environmental and Indigenous groups, as well as a very competitive landscape for LNG globally.[22]

In addition to the development of an LNG network to service the export market, the focus on emissions reduction has been used to highlight natural gas as a potential bridge to a decarbonized future. In 2016, the largest electricity providers in Alberta – ATCO, TransAlta, and Capital Power – announced plans to convert their coal-fired plants to natural gas under the Off-Coal Agreement signed with the provincial government at the time.[23] In addition, Suncor Energy, which sells excess power from its Base Plant generators to the grid, announced that it will be replacing the remaining coke-fired boilers at that asset with natural gas-fired cogeneration units.[24] The combined effects of these varied strategies and opportunities will be to put natural gas in a position to experience significant growth and higher prices – at least domestically – in the coming years. Figure 3 shows the forecasted growth for Canadian natural gas, led primarily by LNG production.

Figure 3: Canadian natural gas production forecast (Saskatchewan, British Columbia, and Alberta)



Source: Canadian Energy Research Institute

Oilsands: death knell or hidden opportunity?

Since the softening of global oil prices in mid-2014, the Canadian oilsands sector has been beset by a seemingly endless barrage of setbacks and challenges, which have tempered investor interest and resulted in massive asset write-downs.[25] The impact of the low-price environment led operators to undertake massive cost cutting efforts, and sparked an acquisition spree by the largest operators between 2015 and 2018, to take advantage of operational synergies.[26] The largest of these included

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[22] Orland, Kevin. 2020. 'Canada's LNG dreams fade as blockades add new costs to industry.' *World Oil.* 8 March. Accessed 21 December 2020. https://www.worldoil.com/news/2020/3/6/canada-s-lng-dreams-fade-as-blockades-add-new-costs-to-industry.

[23] Vriens, Lauren. July 2018. *The End of Coal: Alberta's Coal Phase Out.* International Institute for Sustainable Development. https://www.iisd.org/publications/end-coal-albertas-coal-phase-out.

[24] Suncor Energy. 2019. 'Suncor Energy to invest $1.4 billion in low-carbon power cogeneration at its Oil Sands Base Plant.' 9 September. Accessed 21 December 2020. https://www.suncor.com/en-ca/newsroom/news-releases/1913104.

[25] Herron, James. 'Total takes US$7-billion write down on oilsands projects .' *Financial Post.* 30 July 2020. Accessed 1 February 2021. https://financialpost.com/commodities/energy/total-takes-8-1-billion-writedown-as-pandemic-devalues-oil-gas

[26] Deveau, Scott. 2017. 'Mergers, acquisitions hit decade-high as foreign owners flee oilsands.' *Calgary Herald.* 27 June. Accessed 22 December 2020. https://calgaryherald.com/business/energy/mergers-acquisitions-hit-decade-high-as-foreign-owners-flee-oilsands.

Suncor Energy, which increased its stake in the Syncrude project from 12 to 58.7 per cent, and Canadian Natural Resources Limited (CNRL), which acquired Shell Canada's Albian Mine along with a majority stake in Shell Canada's Scotford Upgrader. Both firms, along with their peers, also achieved significant cost reductions. Cenovus Energy was able to reduce cash costs per barrel from nearly C$15/bbl to just over C$8/bbl, putting the firm right on par with light tight oil operators in the USA.[27] These operational efficiencies also meant that companies are able to generate free cash flow to sustain and debottleneck operations, even with WTI prices as low as $37/bbl.[28] As shown in Figures 4 and 5, these moves were largely effective. Suncor Energy and CNRL, in particular, had cash flows and net earnings approaching pre-2014 levels by 2019, despite average benchmark crude prices being 40 per cent lower in 2019 compared to 2013.[29]

Figure 4: Cash flows for Canadian O&G majors since 2013

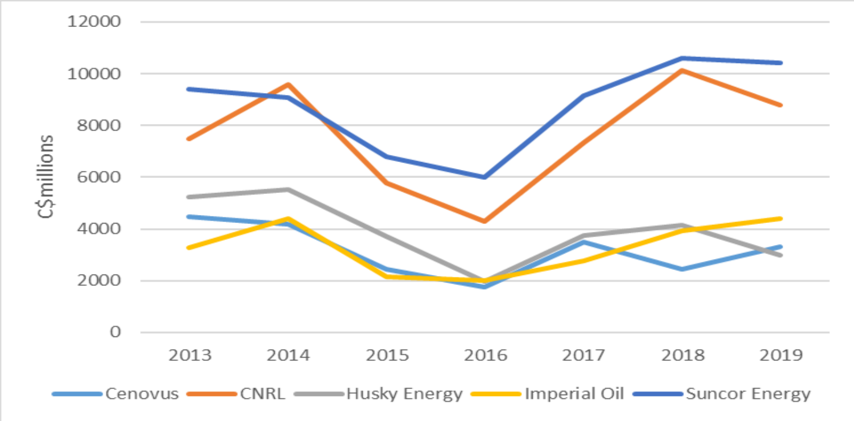
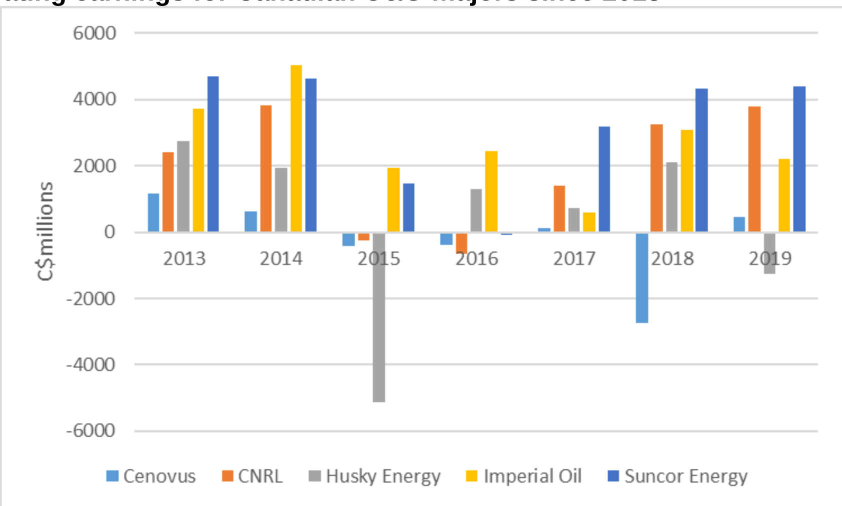


Figure 5: Operating earnings for Canadian O&G majors since 2013



Sources: Figures 4 & 5 – Corporate annual reports. Husky's losses in 2015 and 2019 were related to asset impairments; the WCS price crash in 2018 was key to Cenovus Energy's losses that year.

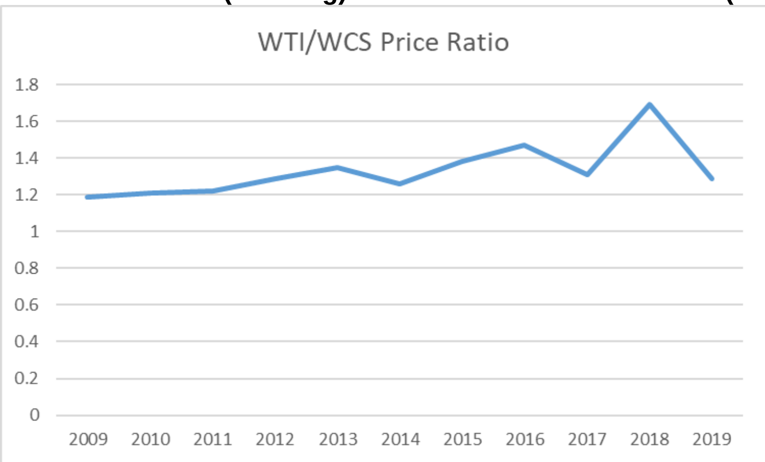
[27] Ihejirika, Nnaziri. 2019. 'The Canadian Oilsands and Strategic Approaches to Profitability.' *Oxford Institute for Energy Studies Energy Insight No. 56*, August.

[28] Healing, Dan. 2020. 'Canadian Natural sets synthetic crude record while recording net loss of $310M.' *Toronto Star.* 6 August. Accessed 28 December 2020. https://www.thestar.com/business/2020/08/06/canadian-natural-beats-expectations-despite-loss-and-halving-of-revenues.html.

[29] Author calculations, based on average prices for Brent, WTI, and WCS between 2013 and 2019.

Several major oilsands projects, including the Kearl and Fort Hills mines operated by Imperial and Suncor, respectively, and the Surmount *in situ* asset operated by ConocoPhillips, were sanctioned between 2010 and 2015. However, investments in pipelines or other takeaway space did not keep pace with this additional production. Although the oilsands benchmark Western Canadian Select (WCS) sells at only a marginal deficit to WTI in Cushing, Oklahoma,[30] the actual price for the same crude blend received by most oilsands producers – based on the WCS price at Hardisty, Alberta – is much lower, due to the unavailability of takeaway space. The effect of this was seen in November 2018, when the differential between WTI (Cushing) and WCS (Hardisty) reached US$50 per barrel, the widest margin ever recorded. The Alberta government introduced production curtailments in late 2018, in order to stabilize the WCS price at Hardisty and provide a measure of revenue certainty – relative to the broader crude market – for oilsands producers.[31] This move helped to stabilize prices, as shown in Figure 6, at the cost of a further erosion in investor confidence.[32] While new US President Biden has revoked the Keystone XL pipeline expansion, the expected commissioning of Enbridge's Line 3 in early 2021 and the Trans Mountain Expansion line in 2022 should add close to 1 mb/d in additional takeaway capacity.

Figure 6: West Texas Intermediate (Cushing) vs. Western Canadian Select (Hardisty)



Source: Corporate annual reports and Author calculations

The ongoing COVID-19 pandemic has also presented further challenges for the sector. A renewed debate and interest in rebuilding global economies that are more decoupled from oil and gas reliance, means that the sector is struggling to attract and retain new investment. With firms focusing on levers within their control, most appear to have returned to the playbook that was successfully employed after the oil price collapse in 2015: improving operational efficiencies and acquiring firms that align with their forward strategy. In the fall of 2020, Cenovus Energy announced that it would be acquiring one of its mid–major integrated rivals, Husky Energy, in a deal that provides Cenovus with low-cost international assets, a reliable upgrader, and a larger refining network.[33] This deal closed in early 2021, creating Canada's third-largest energy producer. Around the same time, Suncor announced that it would be taking over operation of the Syncrude project it owns a majority of, and it also commissioned a pipeline between Suncor Base Plant and Syncrude Mildred Lake. The stated intent of these moves is to optimize

[30] In October 2018, WTI (Cushing) was $US76/bbl, while WCS (Cushing) was US$72/bbl. At the same time, WCS (Hardisty) was US$33/bbl. A lot of emphasis is placed on the WTI–WCS differential, but this highlights takeaway space from Canadian to US markets as the single most important factor in realized prices for oilsands producers.

[31] Bellefontaine, Michelle. 2018. 'Alberta premier announces 8.7% oil production cut to increase prices.' *CBC News.* 2 December. Accessed 21 December 2020. https://www.cbc.ca/news/canada/edmonton/alberta-premier-oil-differential-announcement-1.4929610.

[32] Williams, Nia. 2019. 'Canada's Husky steers investment away from Alberta due to oil curtailments.' *Reuters.* 24 October. Accessed 28 December 2020. https://www.reuters.com/article/us-husky-energy-results-idUSKBN1X31DI.

[33] Canadian Press. 2020. 'Approvals in place for Cenovus buyout of Husky, now expected to close Jan. 1.' *CBC News.* 21 December. Accessed 22 December 2020. https://www.cbc.ca/news/canada/calgary/cenovus-buyout-husky-calgary-oil-petroleum-industry-1.5850688.

major turnaround windows and improve operational performance.[34] CNRL also announced a C$461 million deal to buy natural gas rival, Painted Pony, further entrenching its position as the largest natural gas player in the country – an important part of the firm's value proposition.[35] Still, the industry is broadly expected to report weak earnings for the 2020 fiscal year, with recovery to pre-pandemic levels not expected until 2022.[36]

4. Firm response to decarbonization and the energy transition

The introduction of the federal GHGPPA/OBP in 2018 did not significantly impact the oilsands sector, mostly because it mirrored the compliance requirements established under the provincial CCIR, which meant that they were covered by the latter and by its successor, the TIER. Under current legislation, Alberta's TIER system is required to change its compliance – and tax amount – to match the GHGPPA, or firms will fall under the latter. As a result, oil and gas firms will be paying this tax, which represents a 567 per cent increase from the C$30/tonne CO_2e paid in 2020 and a 340 per cent increase from what was previously assumed to be the cap of C$50/tonne CO_2e after 2021. Keyera Corp., for example, is expected to see its EBITDA decrease by 29 per cent under the new carbon tax scheme.[37]

The impact of this hike on oil and gas firms will be two fold. On one hand, assuming emission intensities per barrel remain constant at 2020 levels, there will be a significant cost increase per barrel. It is estimated that oil and gas firms in Canada paid an average carbon tax of C$0.13–0.33 per barrel under the existing TIER system in 2019.[38] Under the new plan, these firms will be paying between C$0.74 and C$1.87 per barrel. This figure may be even higher, when looking at firms that also have refining operations, where further combustion occurs. For example, in 2019 Suncor paid a carbon tax of C$83 million to Alberta, which works out at C$0.34 per oilsands barrel. Assuming the same emission intensity and production in 2030 under the revised GHGPPA, Suncor will be looking at a carbon tax bill of C$471 million across its upstream and downstream operations in Alberta. While firms are targeting significant reductions in emission intensity per barrel, shown in Figure 7, this rate of progress will need to be accelerated. On the other hand, with consumers also paying the same tax at the pump, there is likely to be a reduction in demand for refined products like diesel, gasoline, and heating oil in order for the 503 MT target to be met by 2030. This will also apply downward pressure on revenues either through lower sales or lower received prices. Considering the ongoing challenges with takeaway space and lower commodity prices, producers do not want further pressure on netbacks. Most of these firms already have carbon mitigation strategies in place, and these are worth summarizing.

To tackle emissions associated with oilsands extraction and upgrading, most new facilities in Alberta are built with cogeneration units, which use natural gas to produce steam and convert the resulting heat to electricity. Cogeneration units reduce emissions by up to 65 per cent compared to an equivalent coke-fired boiler, and by about 30 per cent in comparison to a natural gas boiler with no cogeneration.[39] Not only does this reduce the emissions intensity of the site, but the electricity sent to the provincial grid preferentially displaces coal from the electricity mix, further decreasing the overall emissions of the province. In addition, firms involved in the extraction of bitumen using steam-assisted gravity drainage (SAGD), are increasingly looking at options to use solvents and/or electromagnetic waves to heat up the reservoir in lieu of steam. Pilots for such technologies are underway at several sites, including those

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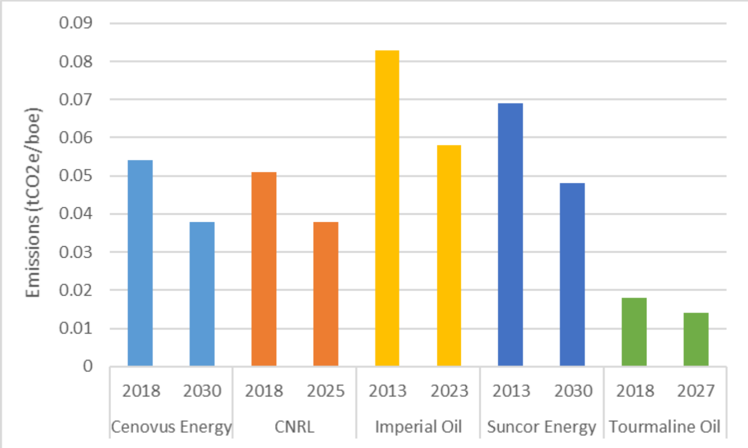
[34] Suncor Energy. 2020. 'Suncor to assume operatorship of Syncrude by end of 2021.' 23 November. Accessed 15 December 2020. https://www.suncor.com/en-ca/newsroom/news-releases/2132338.
[35] Reuters. 2020. 'Canadian Natural Resources buys Painted Pony for $461 million to boost Western Canada acreage.' *Financial Post.* 10 August. Accessed 27 December 2020. https://financialpost.com/commodities/energy/canadian-natural-buys-painted-pony-for-344-mln-to-boost-western-canada-acreage.
[36] Deloitte Canada. 2020. 'Canada's Oil & Gas Sector Faces Slow Recovery.' 6 July. Accessed 20 January 2021. https://www2.deloitte.com/ca/en/pages/press-releases/articles/canada-oil-gas-sector-faces-slow-recovery.html#.
[37] Morgan, Geoffrey. 2020. 'Oilsands emissions intensity 35% lower than reported.' *Financial Post.* 17 December. Accessed 22 December 2020. https://financialpost.com/commodities/energy/oilsands-emissions-intensity-35-lower-drop-another-19.
[38] Morgan, Geoffrey. 2019. 'Here's why the most efficient oilsands companies will pay more under Alberta's new carbon tax.' *Financial Post.* 30 October. Accessed 18 December 2020. https://financialpost.com/commodities/energy/heres-why-the-most-efficient-oilsands-companies-will-pay-more-under-albertas-new-carbon-tax.
[39] Cenovus Energy. 2020. '2019 Environmental, Social and Governance Report'.

owned by Imperial Oil, CNRL, Cenovus, and Suncor. Carbon capture, utilization, and storage (CCUS) has also been deployed at some oilsands sites, most notably at CNRL's heavy oilsands projects. There the CO_2 is captured and reinjected into the reservoirs, reducing the amount of steam required to extract oil and finding a permanent location for the CO_2. In upgrading processes, where a significant amount of gas is used to generate hydrogen for processing sour crude into higher-value sweet crude, carbon capture has been employed at the Quest Carbon Capture facility, operated by Shell Canada. Since 2015, this facility has successfully captured over five million tonnes of CO_2 for storage 2 km underground.[40]

Figure 7: Selected emissions intensity reduction targets



Source: Corporate sustainability reports

While methane does not stay in the atmosphere as long as carbon dioxide does, its emissions intensity is higher. Further, the large LNG projects that are being sanctioned, together with the likelihood that natural gas will continue to play a key role in the country's energy mix, mean that there is growing attention on reducing emissions from this segment.[41] CNRL and Tourmaline, two of Canada's largest natural gas producers, have adopted similar approaches in tackling methane emissions. Both firms use technology – particularly drones and satellites – to monitor and address leak sources. They have also replaced high-bleed pneumatic monitoring devices with low-bleed devices, a move that CNRL says has reduced emissions by 400,000 tCO_2e per year. In addition, the firms have found a creative use for flared gas, using vapour combustion to convert the methane to CO_2, which reduces the overall emissions intensity.[42] Tourmaline has also reported success in being able to mitigate gas venting and flaring, by capturing up to 95 per cent of the vented gas and either using it onsite as a fuel or selling it.[43] Both firms, along with others like Cenovus and Husky have switched from gas-driven injection pumps to solar-powered pumps and metering stations. Firms are increasingly utilizing renewable energy, particularly solar energy, to power their facilities, with natural gas generators providing baseload power backup.

On the refining side, there's less ongoing activity when it comes to decarbonization. However, as the refining process is very similar to the upgrading process, most of the large oilsands firms with significant refining capacity – for example, Suncor, Imperial, and the new Cenovus – are likely to adopt successful upstream technologies further downstream. Key examples of this would be replacing gas-fired boilers with cogeneration units and utilizing solvents to capture the emitted CO_2 post-combustion. One of the

[40] Shell Canada. 2020. *Quest CCS Facility Captures and Stores Five Million Tonnes of CO2 ahead of Fifth Anniversary.* 10 July. Accessed 21 December 2020. https://www.shell.ca/en_ca/media/news-and-media-releases/news-releases-2020/quest-ccs-facility-captures-and-stores-five-million-tonnes.html.

[41] Headrick, Adrienne. 2019. 'High-impact, low-profile: Reducing methane emissions.' *WSP.* 7 October. Accessed 28 December 2020. https://www.wsp.com/en-CA/insights/ca-high-impact-low-profile-reducing-methane-emissions.

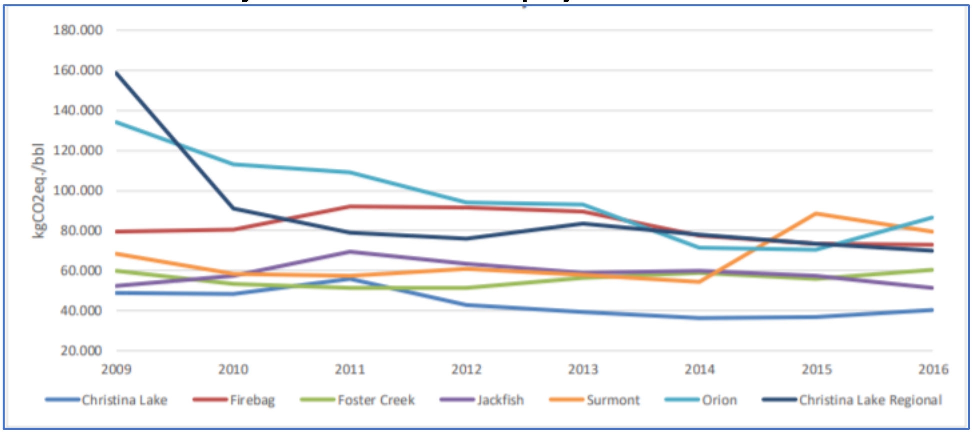
[42] Canadian Natural Resources Limited (CNRL). 2020. '2019 Stewardship Report to Stakeholders'.

[43] Tourmaline Oil. 2020. 'The future is blue and green: Sustainability Report 2019'.

largest opportunities, would be to implement CCUS in hydrogen production, which would remove up to 90 per cent of the CO_2 currently generated through hydrogen production today. This technology, already in play at the Quest facility, could be a game changer for the industry. Another potential game changer is being led by Canada's Oil Sands Innovation Alliance (COSIA), an industry-wide alliance of producers, which focuses on technological innovations that can be applied at its members' sites. Currently, COSIA is developing a technology that could use CO_2 captured from the Scotford upgrader (owned by CNRL and operated by Shell) to generate electricity for the grid,[44] with the revenue generated from the electricity used to offset the carbon capture costs at facilities like Quest and others that may be built in the future.

In addition to the technologies that are applied directly to crude and natural gas production, several companies have also invested in clean fuels, other renewable energies, and in fuel substitutes. These assets have been positioned either as a way to purchase carbon offsets and lower the carbon tax bill for firms, or as a potential route for those firms looking to change their business models and pivot away from a core focus on oil and gas. CNRL has highlighted its work investigating algae as a biofuel or in the manufacture of bio-materials.[45] Suncor operates the largest ethanol plant in Canada, and has also invested heavily in windfarms – including the announcement in 2019 that it would develop a 400 MW wind farm at 40 Mile in Alberta.[46] Suncor and other industry partners like Cenovus have also invested in clean technology funds, investigating topics as varied as finding commercial uses for CO_2, converting waste to biofuels, and developing renewable chemicals. These moves have resulted in significant improvements in emission intensity, particularly in the SAGD/*in situ* production of bitumen, as seen in Figure 8.[47] Considering the mandate to reduce absolute emissions in Canada to 503 MT by 2030, it is likely that a larger step change in emissions reduction will be required by the industry.

Figure 8: Emissions intensity reduction for *in situ* projects



Source : CERI

5. Pathways for enabling technologies

Of the technologies currently being developed – or discussed – by the large oil and gas producers in Canada, a few stand out as having breakthrough potential. The exploitation of these technologies will be required if the industry is to grow production while reducing absolute greenhouse gas emissions between now and 2030.

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[44] Canadian Natural Resources Limited (CNRL). 2020. '2019 Stewardship Report to Stakeholders.'
[45] Ibid
[46] Suncor Energy. 2020. 'Report on Sustainability 2020.'
[47] Canadian Energy and Research Institute (CERI). 2019. 'Canadian Crude Oil and Natural Gas Production and Emissions Outlook (2019–2039).'

Carbon capture across the value chain

CCS is already being used in the industry, notably by CNRL, where the captured carbon dioxide is reinjected into *in situ* reservoirs and used to support enhanced oil recovery efforts. It is also used, as previously detailed, at the Quest carbon capture facility to extract carbon dioxide from the Scotford upgrader's hydrogen units. In both cases, the carbon is captured from hydrogen production and is sent underground. Research from the Pembina Institute suggests that with full penetration of CCS, the oilsands sector could see emissions reduced to 35 MT CO_2e per year by 2040, even with production increasing in line with forecasts.[48] This would represent a reduction in absolute emissions of nearly 60 per cent from 2018 levels, with 50 per cent more production. The biggest drawbacks to widespread adoption of the technology are the costs, storage, and utilization options.

Current carbon costs are estimated to be C$80–100/t$CO_2e$.[49] While firms like CNRL could offset some of these costs by having enhanced oil recovery in addition to cleaner hydrogen, not all facilities have the same business case. Quest, for example, cost C$1.35 billion, which included C$865 million in financing from the government.[50] Even after the CCIR – and subsequently TIER – introduced a firmer carbon tax regime, a tax which was capped at C$50/t$CO_2e$ still made carbon capture unviable in the short term. However, with a price of C$170/t$CO_2e$ by 2030, carbon capture is suddenly in play as a potentially more economic solution. While normal cost-learning would likely have reduced the cost of carbon capture organically, the government's intervention is likely to speed up adoption.

At present, the most tenable solution is to store CO_2 underground, ideally in depleted reservoirs to support enhanced oil recovery. This option would work very well for *in situ* producers, giving them a relatively safe storage location with the added benefit of lower-intensity barrels and cleaner steam generation. However, given the cost of drilling new wells, it may not work as well for refineries or for oilsands mining and upgrading projects, unless more creative storage solutions are found. CNRL is also piloting an innovation at its Horizon site, where CO_2 which is not injected into wells for EOR is instead used to help sequester mine tailings, thus attempting to address another environmental and social issue.[51] While still in the development stage, this could provide options for projects like Fort Hills (Suncor) or Kearl (Imperial Oil), which don't have injection wells onsite.

There appears to be a lot of momentum and excitement relating to the utilization of CO_2. While storing it underground will likely be the option chosen by producers, there's a limit to the volume of CO_2 that can be safely stored in that way, especially in a scenario where there is full penetration of CCS in upstream oil and gas production in Canada. To that end, CNRL's project to utilize CO_2 in tailings reclamation is an obvious candidate for both storage and utilization. Research is also underway to examine other commercial applications for captured CO_2, including the injection of CO_2 into concrete, the development of chemicals and plastics, and even the production of synthetic fuels.[52] COSIA – with industry participants ConocoPhillips, Suncor, Imperial Oil, CNRL, and others – recently partnered with NRG to launch Carbon XPrize, a US$20 million challenge seeking innovative industrial applications for CO_2.[53] Finally, CNRL is leading another COSIA initiative that could see CO_2 used in generating electricity (mentioned in section 4). Utilizing Molten Carbonate Fuel Cells (MCFC) technology, this process would involve the capture of CO_2 from natural gas-fired processing units, with the associated electricity being used onsite or exported to the provincial grid.[54] This could provide an option for facilities

[48] Kilpatrick, Ryan, Adam Goehner, Eli Angen, Matt McCulloch, and Duncan Kenyon. 2014. *CCS Potential in the Oilsands.* Report prepared for Alberta Government, Alberta Innovates, Energy and Environmental Solutions, and Climate Change Emissions Management Corporation, Pembina Institute.

[49] Ibid.

[50] Jaremko, Deborah. 2019. 'Quest CCS project reaches big CO2 storage milestone.' *JW Energy.* 24 May. Accessed 29 December 2020. https://www.jwnenergy.com/article/2019/5/24/quest-ccs-project-reaches-big-co2-storage-mileston/.

[51] Canadian Natural Resources Limited (CNRL). 2020. '2019 Stewardship Report to Stakeholders.'

[52] Roberts, David. 2019. 'These uses of CO2 could cut emissions – and make trillions of dollars.' *Vox.* 27 November. Accessed 28 December 2020. https://www.vox.com/energy-and-environment/2019/11/13/20839531/climate-change-industry-co2-carbon-capture-utilization-storage-ccu.

[53] Suncor Energy. *NRG COSIA Carbon XPRIZE.* Accessed 28 December 2020. https://www.suncor.com/en-ca/sustainability/innovative-technologies/nrg-cosia-carbon-xprize.

[54] Canadian Natural Resources Limited (CNRL). 2020. '2019 Stewardship Report to Stakeholders.'

that would not normally need hydrogen for their processes. Further, the additional value of supplying electricity to the grid would further offset the cost of carbon capture.

Methane capture at source

Outside of direct emissions related to the extraction of oilsands and its conversion to crude oil, the largest source of greenhouse gas emissions in Canada is from the production of natural gas and conventional liquids. While there are solutions for identifying and capturing methane on gas pipelines, and in industrial processes, by far the most impactful options are those which trap the methane at source.

Available technology has been implemented in a growing number of oil and gas fields to eliminate sources of methane leaks. Key among these is the replacement of gas-fuelled injection pumps with electric pumps either powered by local solar panels or from the grid. Others include switching pneumatic testing devices that required high-bleeding of natural gas for calibration to those requiring low-bleed, or eliminating these altogether in favour of instrument air-calibrated devices. Tourmaline has also incorporated waste heat recovery and vapour recovery units in their operations.[55] Heat recovery units capture waste heat from onsite compression and this is used to displace natural gas used in running gas processing units. Vapour recovery units are used to condense and reuse vapours collected in the storage and transportation of natural gas and liquids. These are relatively low-cost solutions that can be applied by small and large producers, and should result in upstream emissions reduction of 25 per cent, according to the firm.

Another potential breakthrough technology being piloted by CNRL is the use of a vapour combustion process to convert its methane emissions to CO_2. While the volume of emitted product would remain the same, the CO_2e emissions would be significantly reduced. While CNRL has not provided any estimates of emissions reduction from these and other technologies, there's clearly a mandate from gas and conventional liquids producers to target methane emissions.

Building the hydrogen economy

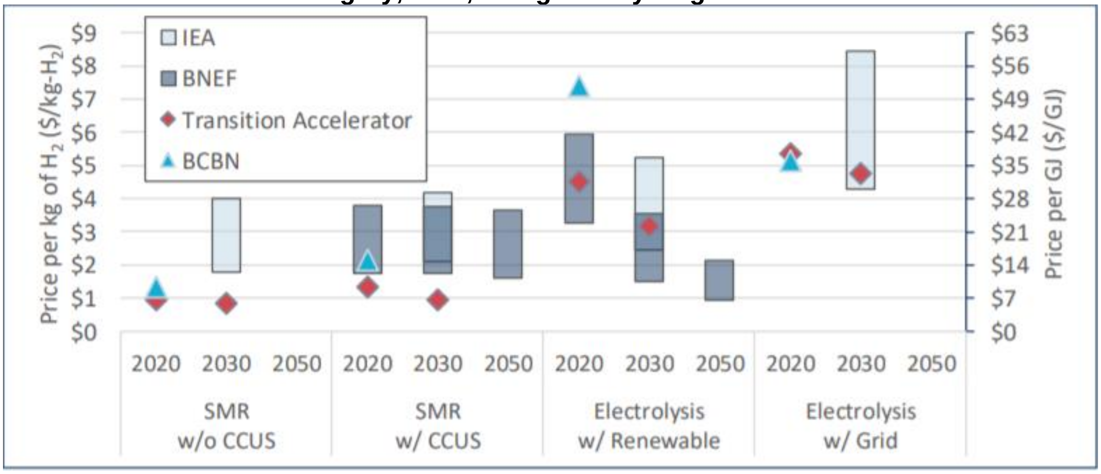
The Government of Canada's Hydrogen Strategy Report[56] has made it clear that there will be significant financial and political support for the accelerated development of hydrogen as an energy carrier in Canada. While green hydrogen is the ultimate goal, with several promising development projects underway, Canada also wants to leverage the fact that it is one of the world's largest producers of hydrogen, albeit grey hydrogen from the steam methane reforming of natural gas. Carbon capture allied with increased methane capture at source will enable further decarbonizing of the natural gas supply chain, and make blue hydrogen more palatable to environmentalists. Key challenges for widespread adoption of blue hydrogen include cost, application, and associated upstream emissions.

The cost associated with developing blue hydrogen from natural gas is linked to the cost required to develop carbon capture in natural gas-fired boilers and reformers. Under a scenario in which carbon capture is commercially viable – a likelihood that has increased significantly with the carbon tax hike – there should be no significant cost barriers to the production of blue hydrogen. The price of blue hydrogen is expected to average C\$1.50/kg H_2 in 2030 when it is projected to be produced at scale, compared to C\$3.20/kg H_2 for green hydrogen at around the same time. For reference, grey hydrogen is currently produced at a cost of C\$1/kg H_2.

[55] Tourmaline Oil. 2020. 'The future is blue and green: Sustainability Report 2019.'

[56] Natural Resources Canada. December 2020. *Hydrogen Strategy for Canada.* Government of Canada.

Figure 9: Forecasted costs for grey, blue, and green hydrogen



Source: Government of Canada

Figure 9 shows expected ranges for hydrogen prices between now and 2050. With carbon taxation, the cost of grey hydrogen is expected to rise, making blue hydrogen the most economic pathway to produce hydrogen by 2030.

Where this hydrogen is used could pose some challenges, however. Most of the hydrogen produced today – including the blue hydrogen produced at Quest – is used in upgraders for the hydrotreating of sour crude oil to produce sweeter blends, or in refineries to crack the bonds required to produce refined petroleum grades. However, 75 per cent of carbon emissions in internal combustion engines occur in end use, or downstream. While there will be value – and proving of the technology – in upgrading and refining crude oil, the real potential for blue hydrogen lies in its downstream applications. There are few commercial uses for hydrogen that could provide immediate markets for producers today, but some options have potential. One of the most talked about options is to use hydrogen to displace as much natural gas as possible for power generation. This process would be similar to the blending of ethanol in gasoline or diesel,[57] and could result in end-use carbon emissions reduction. Another use of hydrogen could be in the production of synthetic fuels which can be used in the transportation sector, particularly segments like long-haul trucking and aviation which are hard to decarbonize.[58] Stretching this to LNG, it’s easy to see how this could also be applied to blue hydrogen, with countries that are able to develop the technology likely to access international markets. Finally, while likely still decades away from commercial deployment, there has been growing talk about the potential of fuel cell electric vehicles (FCEVs), where hydrogen would be used as an energy carrier. Such solutions could offer advantages over other low-carbon transportation options, like standard electric vehicles (eVs), particularly in terms of range.

Other breakthrough decarbonization technologies

Other breakthrough technologies that can be deployed by oil and gas firms in Canada include the use of solvents and/or electromagnetic waves to heat up *in situ* deposits of bitumen. Given the large amount of steam and water used in the recovery process today, this switch could result in eliminating anywhere from 50 to 90 per cent of upstream emissions, for bitumen extracted from *in situ* reservoirs and sent directly to refineries.[59] At the same time, the water and steam saved in this process could conceivably be used to produce hydrogen and excess power, using some of the technologies currently in development. While these alternative extraction methods – including several pilots by Suncor Energy,

[57] JW Energy. 2020. 'Canada poised to lead the blue hydrogen transition.' 16 November. Accessed 28 December 2020. https://www.jwnenergy.com/article/2020/11/16/canada-poised-to-lead-the-blue-hydrogen-transition/.

[58] van Hulst, Noe. 2019. *The clean hydrogen future has begun.* International Energy Agency (IEA).

[59] Emissions Reduction Alberta. 2018. *ESEIEH Project Progress Update.* Accessed 22 December 2020. https://eralberta.ca/wp-content/uploads/2017/05/ESEIEH-Interim-Report.pdf.

CNRL, and Cenovus – have potential, it will be difficult to retrofit existing projects. This means that while future projects are likely to incorporate some or all of these technologies, older (and larger) projects probably won't. As such, their impact on reducing upstream emissions relative to current levels will be minimal.

6. Strategic frameworks and the firm response

The strategic approaches taken by firms can be summarized as: operational, market offerings and new business. It's also worth noting that these focus areas are not mutually exclusive – there are firms with the size and scale to work on all three in parallel, and some are.

Upstream (well-to-tank) emissions are those which can generally be described as being under the control of oil and gas producers. That is, the ability to reduce emissions – or pay a carbon tax in lieu – is a choice the producers have to make. Key activities that are already being utilized to reduce emissions include: using energy efficient equipment in boilers and generators, and increasingly switching to natural gas-fired cogeneration units. The latter can result in upstream emissions reduction of 30–60 per cent, depending on the type of boiler (petroleum, coke, or natural gas) it's displacing. New *in situ* projects are also likely to be built with a combination of solvent and/or electromagnetic heating of the reservoir. However, CCUS appears to be the breakthrough technology with the most potential, as it can eliminate over 90 per cent of the emissions associated with upstream emissions. It is also one of the most ready, having been piloted for several years at both Shell's Quest project, as well as at CNRL's Horizon upgrader. Estimated costs, which at C$80–100/t$CO_2$e were previously thought to be prohibitive, are now potentially competitive with the new carbon tax regime. Based on cost-learning for CCUS, and the expected cost for mitigating carbon, there should be a price equilibrium around 2024. At that point it will be preferable – both economically and socially – to utilize CCUS. The challenge with CCUS, and its ability to be deployed deeply, will largely rest on how well existing facilities can be retrofitted with the technology. Notwithstanding that, in the near term, it is expected that most of the larger firms in the industry – particularly CNRL, Suncor, and post-merger Cenovus – will be developing and deploying CCUS technology in existing operations increasingly. The deployment of CCUS will also result in a significant ramp up in blue hydrogen production. The added cost of doing this for firms already producing grey hydrogen should be minimal in that scenario. Near-term, it is likely that blue hydrogen production will be limited to what is required for firms to operate existing upgrading and refining assets. Longer-term, there will be a hope that this spurs the innovation required to develop a broader-scale commercial hydrogen network for transportation and heating, which could turn blue hydrogen into a valuable revenue stream for both oil and natural gas producers.

With the introduction of the carbon tax hike, consumers are also facing the same pressures as firms. The expectation is that by 2030, Canadians will be paying an extra C$0.40/litre at the pump.[60] For reference, that price represents about 40 per cent of the average gasoline price in December 2020 across much of Canada. The tax would also apply to the prices for natural gas, a key component of the energy mix in most provinces. The only way to combat the expected drop in crude oil demand is for firms to increase their low-carbon fuel offerings, primarily through biofuels. Firms are likely to look at increasing the ethanol content in their diesel and gasoline, as well as developing new biofuels using no – or decarbonized – fossil fuels. Firms active in this area include Suncor, which operates the largest ethanol plant in Canada and – along with Shell Canada – has also acquired a significant stake in Enerkem, a waste-to-fuel developer which operates a plant in Alberta and has proposed building two more.[61] CNRL is also actively researching algae-based biofuels, and has announced this as a core part of its net-zero emissions target for 2050.[62] The development of liquefied hydrogen and FCEV

[60] Ballingall, Alex. 2020. 'Ottawa proposes steep hike for carbon tax to meet greenhouse gas target.' *Toronto Star.* 11 December. Accessed 2 January 2021. https://www.thestar.com/politics/federal/2020/12/11/ottawa-proposes-steep-hike-for-carbon-tax-to-meet-greenhouse-gas-target.html.

[61] Enerkem. 2020. *CAD$875 million biofuel plant in Varennes, Québec.* 8 December. Accessed 29 December 2020. https://enerkem.com/newsroom/releases/?communique_id=122575.

[62] Canadian Natural Resources Limited (CNRL). 2020. '2019 Stewardship Report to Stakeholders.'

infrastructure could also help in this regard, although this is considered to be far removed from commercialization.

The third strategic pathway for firms is to integrate forward in the value chain, and either develop or expand commercial opportunities for commodities like electricity and CO_2. This strategic approach could appeal to oilsands firms that don't have the financial wherewithal – or need – to develop hydrogen as a commodity, particularly those that do not have upgraders or refining capacity. While such firms may choose to invest in – or adopt – CCUS, the added value other firms have from hydrogen production may not be there and so a focus on other commodities will be needed. MEG Energy and PetroChina are examples of firms that could go down this path. For such firms, in addition to supporting EOR, CCUS combined with cogeneration could be used to generate excess power for the grid and sequester CO_2. While this still entails business risk – given that those commercial pathways are not as lucrative or are still being developed – it allows these smaller firms to stay within their current operational profile. Larger firms are also likely to get involved in this space, and it is highly likely that by 2030, some of the largest electricity generators in Alberta will be the oilsands players like Imperial Oil, CNRL, Cenovus, and Suncor Energy.

Other strategic options available to companies include: pivoting entirely away from the oil and gas industry to focus on mineral mining for electric batteries, or towards renewable energy development such as offshore tidal and wind power, geothermal energy development, and solar energy (both PV and concentrated). These are technologies that can take advantage of core competencies already existing in oil and gas firms – mining, offshore exploration, drilling, fracking, and large-scale utility plant operation. In fact, some firms – particularly Suncor Energy – are already involved in some of these areas as means to diversify and take advantage of emissions offsets. However, it is unlikely that firms will pivot entirely away from oil and gas, given the plentifulness of both resources in Canada.

7. Conclusion

The carbon tax hike could not have come at a more difficult time for the Canadian oil and gas industry. For oilsands firms, the COVID-19 pandemic has further exacerbated ongoing commodity price sluggishness amid softening demand for crude oil in most parts of the world. Takeaway space continues to be a concern for the sector, especially with the recent election of Joe Biden as US President and his decision to revoke Keystone XL's permit. Natural gas firms are also facing their own challenges, with prices that have been low for over a decade and the debottlenecking of even more natural gas production across the world. There are some silver linings in the clouds, however. The construction of Enbridge's Line 3, albeit delayed, looks like it will be completed in 2021. The TransMountain pipeline, owned by the Canadian government, is also on track for 2022 delivery. LNG projects are proceeding as planned, with several expected to be commissioned over the next decade. The COVID-19 pandemic is likely to wreak significant havoc on 2020 earnings, but it's a measure of the industry's resilience that the larger and mid–major firms continue to exist, despite minimal investment, without the bankruptcies and liquidations seen in the US light tight oil (LTO) sector.

Although the carbon tax hike could be seen as a major threat to industry viability – by potentially increasing costs and reducing demand – it may have forced open the door to the industry's future. Several of the enabling technologies required to decarbonize are already in existence, at least at the pilot phase, from CCUS applications in EOR and blue hydrogen development, to the use of solvents and electromagnetic waves to warm up *in situ* reservoirs, and the development of plant and synthetic biofuels. Where it was previously uneconomic to develop some of these technologies, they are now likely to be cost-competitive on a commercial basis against the proposed carbon tax, for some as early as 2024. Key among this, and already a major plank of Canada's national resource strategy, is the development of a hydrogen economy. The strategic options into which these technologies can be packaged allow firms to minimize their own emissions in order to sustain revenues and grow, to offer low-carbon products to consumers that maintain liquid fuel demand, or to expand their revenue streams through increased sales of electricity and, potentially, CO_2.

There are continued risks, however. The rate of decarbonization has gathered pace over the past two decades; each year bringing with it a lower tolerance for fossil fuels, especially among the younger generations facing the impacts of climate change. Not only will the industry's ability to adapt to change be tested in the coming years, but so will the speed at which it can do so. It is also possible that the industry players will need to diversify their product offerings to sustain revenues, with electricity and CO_2 in particular seen as options for new – or increased – monetization. While the paths to future profitability in a low-carbon world are not clear cut for Canadian oil and gas firms, they appear to be approaching the challenge in much the same way as they have approached previous challenges – from profitably extracting resources in a harsh environment, to driving down business costs and operating under immense global scrutiny. In that light, the carbon tax hike, perhaps a short-term albatross on a beleaguered industry, is likely to be the catalyst required to drive the adoption of emissions-reducing technologies that could set the stage for a new cycle of investment and profitability.

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