

Net gains

How the federal-Alberta grand bargain can increase oil sands profitability



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Oil sands facility-level operational finance modelling by Rory Johnston, Commodity Context

Contents

Abbreviations	1
Executive summary	3
Findings	4
Introduction and background	5
Summary of results	6
Reasons for the WCS-WTI price differential	8
Key considerations in oil industry economics and emissions policy	11
Transportation differentials	11
Tolls	12
Royalties	13
Emissions from Alberta's oil sands	15
Estimating emissions from oil sands projects	17
Results: Profitability growth from a pipeline outweighs carbon costs	20
Project-specific analysis	20
Future value analysis	28
Conclusion	32
Appendix	33

Who we are

Clean Prosperity is a Canadian climate policy organization. We advocate for practical climate solutions that reduce emissions and grow the economy. Learn more at CleanProsperity.ca.

Abbreviations

BVM	Bitumen Valuation Methodology
FSB	facility-specific benchmark
HPB	high-performance benchmark
MOU	memorandum of understanding
OBPS	output-based pricing system
PWAEI	production weighted average emissions intensity
TIER	Technology Innovation and Emissions Reduction (regulation)
WCS	Western Canadian Select
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate

Executive summary

The November 2025 federal-Alberta memorandum of understanding (MOU) is a grand bargain between governments that have spent a decade in conflict over climate and energy policy. The agreement commits to industrial decarbonization while boosting Western Canadian energy exports.

This paper examines the impact of two critical MOU provisions on Alberta's oil sands industry: raising the minimum effective carbon credit price to C\$130 per tonne and adding new bitumen pipeline capacity. We assess the net profitability effect of these increased carbon costs and the future value of increased export capacity for four representative oil sands projects.

The oil sands are of enormous economic importance to Alberta and Canada. Public revenues from the oil sands depend on the price of the Western Canadian Select (WCS) crude blend. Public revenues increase with producer profitability, because mature oil sands facilities pay royalties based on their net profits.

WCS crude trades at a discount to the benchmark West Texas Intermediate (WTI) blend due to its inferior quality and the cost of transporting it to market. Egress capacity from the landlocked Western Canadian Sedimentary Basin is historically the largest and most volatile driver of the WCS-WTI price differential. New pipeline capacity that avoids the need to ship oil sands crude via more expensive rail could reduce the price differential by US\$5 per barrel over the long term. This would increase revenues and profitability for oil sands facilities.

The oil sands sector accounts for about a third of Alberta's total greenhouse gas emissions, making it the highest-emitting sector in the province. Like other large emitters, oil sands facilities are regulated under the province's carbon pricing system, the Technology Innovation and Emissions Reduction (TIER) regulation. Emitters pay a carbon price on their emissions per unit of production over a benchmark, or generate carbon credits, which they can sell to other emitters, for emitting below the benchmark.

This paper looks at the impact of MOU implementation on the profitability of four facilities that together account for one-quarter of total oil sands bitumen output. The facilities have a range of emissions intensities. Cenovus Energy's Christina Lake facility and Imperial Oil's Kearl mine are best in class, Suncor Energy's Firebag facility has a mid-range emissions intensity, and Imperial's Cold Lake is one of the most emissions-intensive facilities in the province.

Findings

1. The benefits of increased pipeline capacity outweigh the increase in carbon costs agreed in the MOU. When new pipeline capacity comes online, the resulting sustained reduction in the WCS-WTI differential increases per-barrel profitability for the facilities we analyzed by 30% to 91%, net of carbon costs.

Under the MOU, carbon costs at these facilities would increase from between C\$0.53 and C\$2.46 per barrel to between C\$0.81 and C\$3.75 per barrel at the time that new pipeline capacity is likely to come online, relative to a scenario where Alberta keeps its industrial carbon price frozen at C\$95 per tonne. But these cost increases are far outweighed by an increase in profitability of more than C\$10 per barrel at all the facilities we analyzed, resulting from the reduction in the WCS-WTI differential.

2. The increase in profitability from new pipeline capacity will allow most oil sands facilities to quickly recoup all their additional carbon costs.

Under the MOU, TIER costs could start increasing before new pipeline capacity is built. The increase in profitability from a new pipeline is significant: three of the four facilities analyzed recoup all their additional interim TIER costs (between now and the opening of the pipeline) within one year of the pipeline beginning operations. This is driven primarily by the resulting reduction in the WCS-WTI differential.

3. New pipeline capacity significantly increases both net profits for oil sands facilities and provincial royalty revenue. For the four facilities we analyzed, new pipeline capacity increases per-barrel profitability and allows facilities to increase production. This results in a C\$3.16 billion nominal increase in annual profits in the 15 years following the opening of new pipeline capacity that reduces the WCS-WTI differential, and a C\$957 million annual increase in provincial royalties.

The benefits of increased pipeline capacity significantly outweigh the increase in carbon costs agreed to in the federal-Alberta memorandum of understanding.

Introduction and background

The November 2025 memorandum of understanding (MOU), signed by the federal and Alberta governments, commits to industrial decarbonization while increasing export opportunities for Western Canada's oil and gas. The MOU is part of a grand bargain between two governments that spent over a decade in conflict over energy development.

This paper looks at the potential impact of two MOU provisions that are critically important to Alberta's oil sands industry. These are the agreements to raise the minimum effective price of Alberta carbon credits to C\$130 per tonne, and to add new bitumen pipeline capacity to the West Coast. The paper analyzes the net profitability impact on specific Alberta oil sands facilities of both an increase in carbon costs and an increase in export capacity.

The oil sands are of enormous economic importance to Alberta and Canada. In calendar year 2024, the Alberta oil sands industry produced an average of 3.39 million barrels per day of cleaned bitumen, valued at C\$86.9 billion.¹ The industry paid operating, capital, and other costs – largely into the Canadian economy – of C\$38.2 billion and royalties of C\$16.3 billion to the Alberta Treasury. Oil and gas are Canada's largest exports, by far, and a major employer in the Canadian economy.

Federal and provincial public revenues from the oil sands depend on the price that producers get for their product in the market and the profitability of their operations. Oil sands crude is marketed as Western Canadian Select (WCS), which trades at a discount to the U.S. benchmark West Texas Intermediate (WTI) crude.

Oil prices are determined in a global marketplace, and Canadian producers are price takers in this market, not price setters. Canadian producer revenue is determined not only by the price of WTI crude, but also by the fluctuating price differential between WTI and WCS crude. As we discuss below, the price difference is primarily due to two factors: the lower quality of WCS crude, and the additional cost of transporting it to markets.

The largest and historically most volatile driver of WCS-WTI price differentials is the second of these factors: the availability and cost of egress capacity from the landlocked Western Canadian Sedimentary Basin (WCSB). Keeping the transport component of the differential as low as possible in order to maximize revenues is a key objective for Canada. Building new pipelines with low

¹ This represents an effective (i.e. ex-diluent) cleaned bitumen price of roughly C\$73 per barrel, given an average West Texas Intermediate crude price of US\$77 per barrel, a Western Canadian Select differential of US\$16 per barrel, and an exchange rate of 1.38 USD/CAD.

transportation costs to markets other than oversupplied parts of the U.S. is the surest way to keep these differentials low without Canadian producers needing to restrict their production.

The oil sands sector accounts for around a third of Alberta's total emissions, making it the single largest emitting sector in the province. Carbon markets are the core approach to reducing industrial emissions in Canada. Alberta was the first province to create a carbon market in 2007. Its current system, the Technology Innovation and Emissions Reduction (TIER) Regulation, has been in force since 2020.

TIER is an output-based pricing system (OBPS). Under an OBPS, the government sets a performance benchmark for each facility, defining its maximum emissions intensity in terms of emissions per unit of production, such as a barrel of oil or a tonne of cement. A facility's total emissions limit is thus tied to its total production output. Benchmarks are generally lowered over time. Facilities that overshoot their benchmark and exceed their emissions limit have to pay a carbon price or buy credits from other facilities. Conversely, facilities that emit below their benchmark generate credits they can sell to other emitters. This system allows facilities to expand production without automatically incurring higher per-unit costs, thereby balancing environmental objectives with economic growth.

Summary of results

This analysis asks whether the costs of increased TIER credit prices for oil sands producers outweigh the benefits of increased pipeline capacity, specifically the avoidance of structurally wider WCS-WTI price differentials. A new pipeline that can transport an additional one million barrels per day will allow Canadian producers to avoid shipping bitumen by more expensive rail transportation. Shipping oil by

rail has historically cost US\$5 more per barrel than pipeline transport. New pipeline capacity that prevents additional use of rail should result in higher profitability for companies.



We look at four major oil sands projects at different points on the spectrum of emissions costs to evaluate the potential impact of the federal-Alberta MOU on profitability. We find that for low-emissions facilities, the increase in profit from a lower WCS-WTI differential vastly outweighs the costs from TIER credits increasing to C\$130 per tonne.

New pipeline capacity will likely take another six to 10 years to build given construction timelines. Nevertheless, we find that once this new capacity comes online it will boost

profitability enough to enable low-emitting oil sands facilities to quickly recoup all the additional carbon costs they incur between now and pipeline commissioning.

Even for the oil sands facilities that face the highest costs under TIER – those that are both high-emitting and have seen their emissions increase in recent years – the increase in profitability from a new pipeline still outweighs likely 2035 carbon costs. However, facilities with higher emissions intensities than in the past, or with emissions intensities considerably above best-in-class facilities, face a significantly longer payback period.

Improved facility-level profitability will drive a considerable increase in the royalties collected by Alberta and corporate income taxes paid to the Alberta and federal governments.

We analyze four large oil sands facilities: Cenovus Energy's Christina Lake facility, Imperial Oil's Kearl mine, Imperial's Cold Lake facility, and Suncor Energy's Firebag facility. Together, these facilities account for roughly one-quarter of total oil sands bitumen output. These four projects span a range of emissions intensities, from best-in-class at Christina Lake and Kearl, to mid-range performance at Firebag, to one of the most emissions-intensive facilities in the province at Cold Lake.

None of these projects are forecasted to generate carbon credits in 2035. Our analysis seeks to show the profitability impact of new pipeline capacity and increased TIER carbon costs for facilities that are most likely to bear compliance or decarbonization costs. Many [oil sands facilities](#) are credit generators and may remain so over the next decade.²

Figure 1 (below) shows the net change in per-barrel profits at each facility in 2035 as a result of realizing the MOU's commitments to build significant new pipeline capacity and achieve a minimum effective TIER credit price of C\$130 per tonne. These findings assume that TIER credit prices increase at a rate of C\$5 per year beginning in 2026. The findings also assume a WTI price of US\$65 per barrel and a reduction in the WCS-WTI differential from US\$18 to US\$13 per barrel. The findings are discussed in greater detail below.

² Carbon cost estimates are dependent on the future design of the TIER system, including benchmark tightening and carbon price trajectories beyond 2026. Our facility-specific, 2035-horizon findings are consistent with estimates from other [organizations](#), which assume the current federal headline price trajectory and a 2030 timeframe.

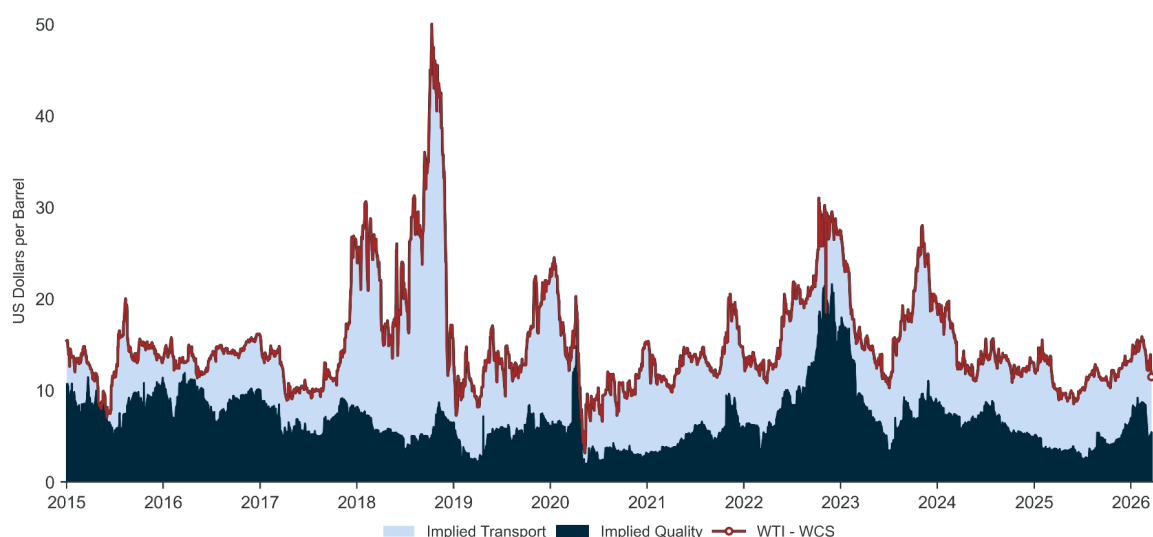
Figure 1: MOU-driven profitability growth across four representative oil sands projects



Reasons for the WCS-WTI price differential

WCS is a heavy, sour crude oil blend made of bitumen mixed with lighter hydrocarbon diluents to facilitate transport. It is Canada's major export blend and its market price determines the value of raw oil sands bitumen. Like all crude oils, the price of WCS is driven by a range of factors. WCS almost always trades at a discount to WTI, for two main reasons: chemical make-up (i.e. quality) and geographic location of production. Figure 2 (below) graphs the variation in the WCS-WTI differential over time, distinguishing the relative contribution of these two factors.

Figure 2: Drivers of the WCS-WTI price differential



Note: Implied Quality = WCS-WTI differential at Cushing, OK; Implied Transportation = WCS Hardisty vs WCS Cushing.
Sources: Commodity Context, Bloomberg.
Disclaimer: These materials incorporate third-party data, are provided for informational purposes only, and do not constitute advice or opinion of any kind. Commodity Context does not warrant or guarantee the accuracy or completeness of these materials.

Quality

WCS is both a heavy and sour crude oil. Heavy crude is dense and viscous, and more expensive to refine into fuel products like gasoline, diesel, and jet fuel, in comparison with light crudes such as WTI. Sour crude contains high levels of sulfur that needs to be removed during refining to meet environmental regulations. This also makes WCS more expensive to refine than WTI, which is a sweet, or low-sulfur, crude.

The price differential between WCS and WTI crude attributable to WCS's lower quality is approximately US\$6 per barrel, based on the price of WCS in Cushing, Oklahoma, where WTI is priced and transportation costs are no longer a factor. As shown in Figure 2, this quality differential changes over time based on supply and demand for heavy crudes and the capacity to process them. Importantly, for the purposes of this analysis, the quality-related differential is largely unrelated to Canadian policy.

Geography

The primary WCS contract is priced for physical delivery in Hardisty, Alberta. Hardisty is far from the major heavy oil refining capacity in the U.S. Midwest or along the Gulf Coast, and the cost of transportation is reflected in WCS-WTI price differentials. When pipeline capacity is sufficient, marginal transportation cost equals the marginal pipeline toll (currently US\$7 per barrel). When capacity is insufficient, marginal transportation shifts to rail, which typically costs at least US\$5 more per barrel. This widens the differential.

Even a small, sustained surplus of supply from Western Canadian producers relative to egress capacity can dramatically increase the WCS-WTI price differential. In 2018, pipeline capacity was

insufficient, oil-by-rail capacity was overrun, and storage capacity was exhausted. WCS differentials, driven by marginal egress costs — at that point, effectively disposal — quickly rose to an all-time high of US\$50 per barrel. This prompted the Alberta government to forcibly curtail crude oil production in the province by 325,000 barrels per day. The curtailment intervention, though enduringly controversial, succeeded in tightening the differential, which narrowed from US\$50 per barrel in mid-October 2018 to an exceptionally tight US\$7.25 per barrel by mid-January 2019, before normalizing back to around US\$13 per barrel.

Key considerations in oil industry economics and emissions policy

If the Western Canadian oil industry gains access to greater egress capacity, this can help minimize the WCS-WTI price differential. The events of 2018 showed that the WCS differential is set by the marginal barrel, meaning the final barrel to clear the market. The price of the marginal barrel sets the price for all barrels produced in the WCSB. Even modest shortfalls of egress capacity can spiral into acute crises in upstream pricing.

At the same time, future pipeline projects — including new pipelines and pipeline expansions — should be carefully structured to ensure that they contribute to reducing the WCS-WTI differential. The Trans Mountain Expansion Project highlighted the risk that runaway pipeline construction costs can lead to high tolls that increase marginal barrel prices.

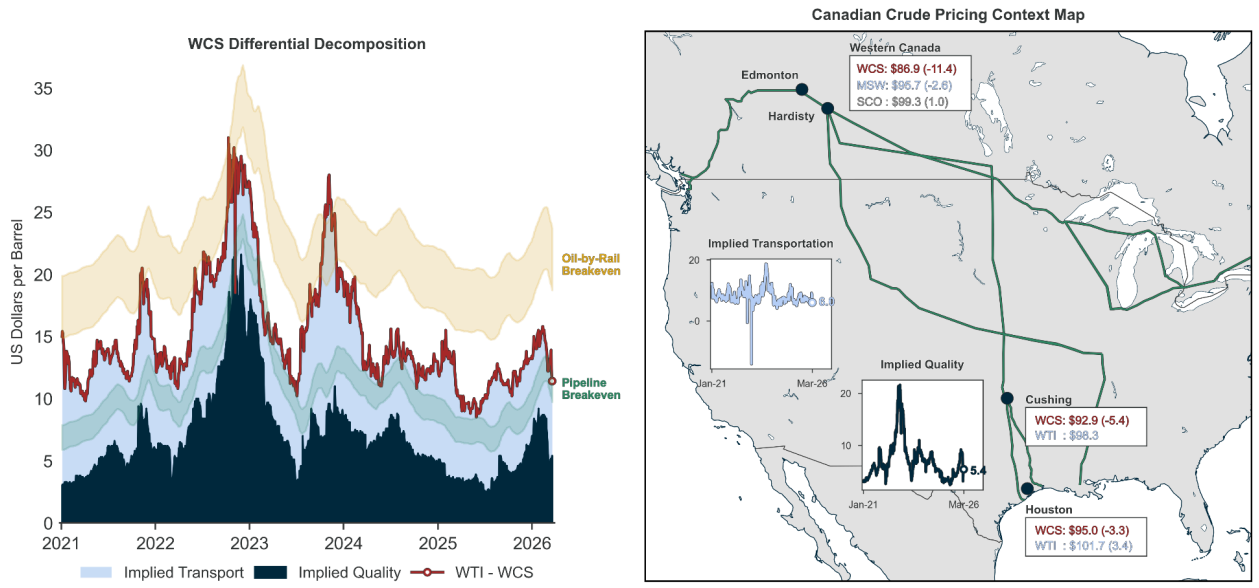
There are considerations involved in pipeline and upstream capacity expansion that go beyond what we consider here. For example, increased production to fill expanded pipeline capacity may require developing lower-margin projects. A lower WCS-WTI differential affects project economics differently than company-wide profitability; some companies will have hedging or refining strategies that mitigate these concerns. Increased pipeline capacity to the U.S. may reduce the need for additional West Coast egress. Our analysis considers the potential value of a new pipeline that shrinks potential future WCS-WTI price differentials.

There are also global trends that will determine the general appetite for investment in Canada, and our analysis is neutral on the overall competitiveness of Canada's investability relative to competitors. For example, overall cost competitiveness, permitting approval speeds, regulatory costs, additional government policies, and the risk profile of Canada's oil reserves will influence the interest of global capital in Canadian investment. Global oil prices will also influence investment decisions. Our analysis asks how the implementation of the federal-Alberta MOU could impact oil sands profitability.

Transportation differentials

If insufficient pipeline capacity shifts the marginal transportation of WCS crude to more expensive rail, the total WCS-WTI price differential in Hardisty, Alberta, can increase to US\$18 per barrel.

Figure 3: WCS-WTI differentials and transport break-even points



Note: Implied Quality = WCS-WTI differential at Cushing, OK; Implied Transportation = WCS Hardisty vs WCS Cushing; green pipelines are major Canadian crude carriers.
 Sources: Commodity Context, Bloomberg.
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In cases of extreme oversupply, as in 2018, transport costs can push the differential past US\$18 per barrel, until producers are forced to shut in production or the provincial government imposes curtailment. Under current conditions our analysis assumes a stable, if economically sub-optimal, WCS-WTI differential of US\$18 per barrel. We project that a new million-barrel-per-day pipeline would allow for expansion of oil sands production without extensive crude-by-rail shipments, thereby reducing the price differential. An [analysis](#) of the Trans Mountain Pipeline Expansion found that it reduced the WCS-WTI differential by about US\$8/barrel. Although that analysis argues that a new pipeline would not reduce differentials further, additional expansion of oil sands production would likely put renewed pressure on differentials that only new pipeline access would alleviate.

Tolls

Marginal pipeline tolls are the primary driver of the geographic price differential for WCS and bitumen. Tolls are critical not just for the project economics of a pipeline but for the economics of the entire WCSB upstream oil industry. The Canada Energy Regulator sets tolls on interprovincial pipelines based, typically, on both the cost of construction and operation as well as some regulated rate of return. Toll rates have been impacted by the ballooning costs of pipeline construction. Most recently the 590,000 barrel Trans Mountain Expansion Project saw its price tag spiral from an initial cost of C\$5.4 billion to approximately C\$35 billion by the time it entered service.

The current uncommitted toll to ship a barrel of heavy crude from Edmonton to the Westridge Terminal at the Port of Vancouver via the Trans Mountain pipeline is C\$14.40 per barrel, which is more than twice the C\$6.60 per barrel cost to ship from Edmonton to Flanagan, Illinois, on the Enbridge Mainline. Once at the Westridge Terminal, Canadian barrels still need to price in tanker transportation to the end destination; transportation to China is an additional US\$3 or more per barrel, for example.

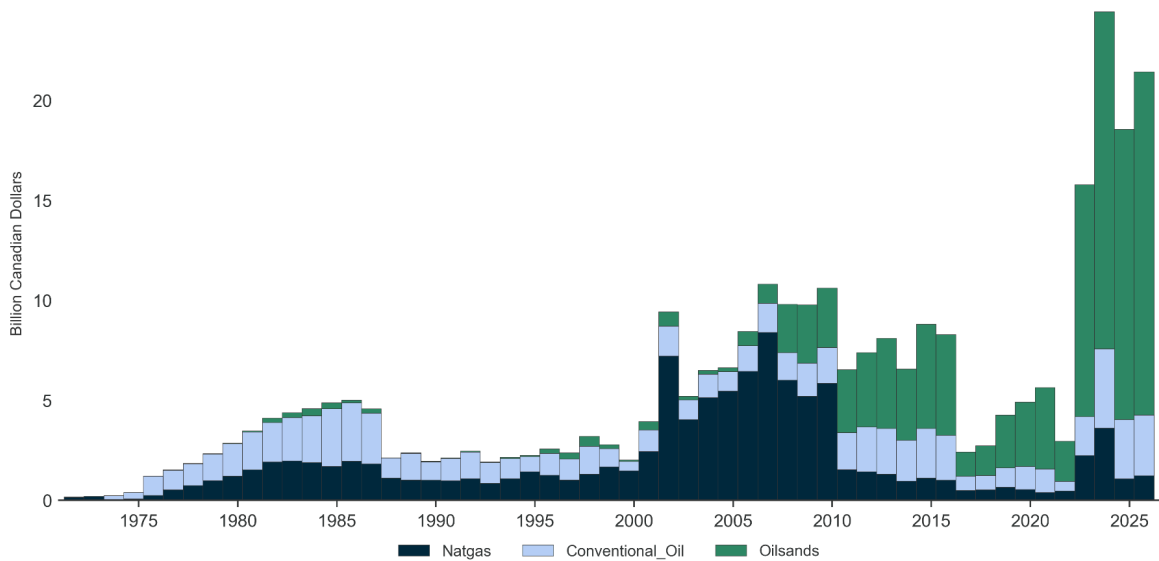
Moreover, 80% of the current Trans Mountain system's flow are committed barrels on take-or-pay contracts, which has initially shielded basin-wide pressure on marginal prices. Take-or-pay capacity will be used first, meaning that these higher tolls don't weigh on marginal pricing. However, the economics of shipping on the expanded Trans Mountain system will, undoubtedly, start to put additional widening pressure on the WCS differential once the approximately 180,000-barrel uncommitted portion of the system is required to clear the basin, because it will then be the higher tolls determining marginal egress costs.

The federal-Alberta MOU stipulates that new bitumen pipeline capacity will be privately built and financed. Tolls would need to cover the cost of construction plus a rate of return commensurate with the high risk of pursuing the project, given that similar projects have faced delays, cost overruns, and cancellations. A toll set as high or higher than Trans Mountain's uncommitted rate would likely increase the WCS-WTI differential, thereby devaluing all barrels produced in the basin and eroding the value of incremental takeaway capacity. Our analysis assumes that the tolls charged by a new pipeline would not systematically increase the WCS-WTI differential.

Royalties

Royalties are the most direct financial stake that Albertans have in the value received for bitumen produced from the oil sands. Royalties reflect the value to Albertans of resource companies unearthing the oil that the people of Alberta own. Over the past half-decade, royalties have ballooned due to a combination of higher oil prices, healthier WCS differentials thanks to increases in pipeline capacity, and projects being required to pay higher royalty rates as they recoup their capital costs. Oil sands royalties have soared to more than C\$17 billion in 2025 from \$950 million in 2006 (see Figure 4 below).

Figure 4: Alberta oil and gas royalties, 1974-2025

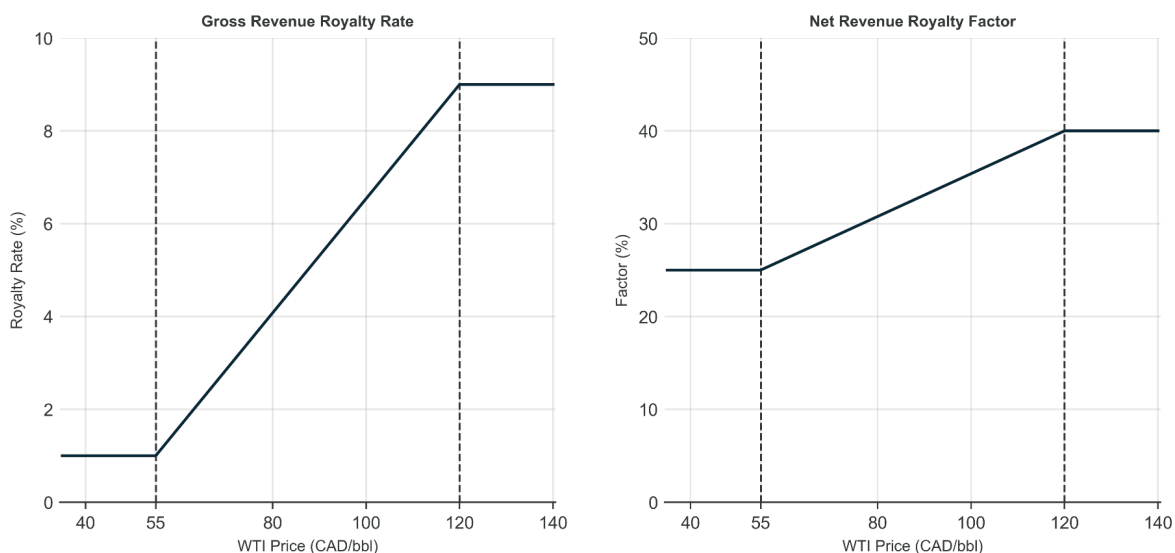


Note: Fiscal year ends March 31
 Source: Commodity Context, Alberta Government.
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Oil sands projects that haven't recovered their capital costs are said to be "pre-payout," and pay royalties at a rate of 1% of gross revenues at WTI prices up to C\$55 per barrel. Their royalties increase to a maximum of 9% of gross revenue as WTI prices rise to C\$120 per barrel. A "post-payout" project has recovered its capital costs and pays the greater of either the pre-payout royalty calculation, or between 25% and 40% of net revenues, again increasing as the price of WTI crude increases from C\$55 per barrel to C\$120 per barrel (see Figure 5).

A long-established and highly profitable facility such as Cenovus Energy's Christina Lake is now in the post-payout royalty period, while the more recent Imperial Oil Kearl oil sands mine, which incurred a very large upfront capital cost, is still recouping its initial investment and is in the pre-payout period.

Figure 5: Alberta oil sands royalty rates



Sources: Alberta Government.
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In recent years many oil sands projects have shifted to post-payout status, driving the Alberta royalty windfall that began in 2022. As a result, Alberta’s fiscal sensitivity to changes in crude prices and WCS differentials is much higher today than during the egress crisis of 2018. Albertans benefit relatively more from price increases for post-payout projects and, on the flip side, face larger declines in public revenues as oil prices fall or WCS-WTI differentials widen. The impact of an increase in the WCS-WTI differential on the royalties paid by a profitable post-payout project is much larger in absolute terms than the impact would have been on the same project during its pre-payout period, when it paid a much lower royalty rate.³

Emissions from Alberta’s oil sands

The oil sands sector accounted for just less than [33% of Alberta’s total emissions](#) in 2023, making it the highest-emitting sector in the province. In Alberta, emissions from the oil sands and other large industrial sources are regulated through a combination of provincial carbon pricing and emissions-management policies, such as methane regulations. This analysis focuses on the impact of the TIER regulation, which applies to high-emitting facilities. Under TIER, regulated companies must

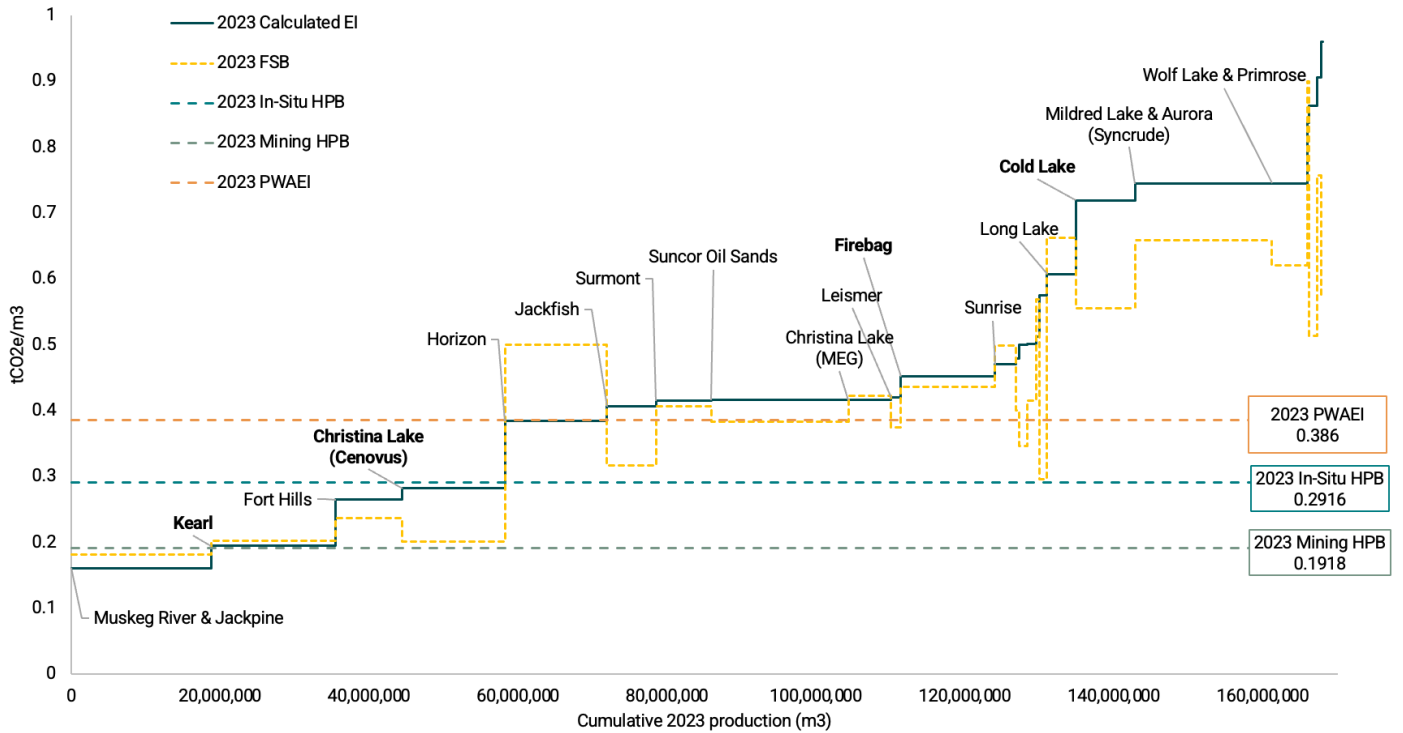
³ An increase in profits from individual facilities also likely translates to higher profits for the companies that own them and therefore higher federal and provincial corporate income tax revenues. For the purposes of this report, we focus on project economics, not company economics, so we cannot confidently ascribe company-level profitability to the performance of specific facilities.

meet emissions benchmarks. They can reduce emissions directly, use approved credits for reductions, or pay into a provincial fund if they exceed their targets.

Under TIER, large industrial facilities — including many in the oil sands — are given an annual emissions target based on a benchmark. The benchmark defines how much a facility is allowed to emit per unit of production. Oil sands producers can choose between two benchmarks. The first option is a facility-specific benchmark (FSB), based on that facility's own historical performance. This benchmark requires the facility to emit less per unit of production compared with its own past performance. The second option is the high-performance benchmark (HPB), based on the average emission intensity of the top-performing 10% of facilities in a given sector for a particular product. This flexibility prevents facilities with low emission intensity from being penalized by TIER's standard facility-specific benchmarking method.

Figure 6 (below) compares the estimated facility-specific benchmarks and 2023 emission intensities across oil sands facilities using 2023 data, illustrating the impact of this approach and the differences in emissions intensity across projects. Notably, FSBs are substantially higher for facilities with greater emission intensity.

Figure 6: Estimated 2023 emission intensity and facility-specific benchmarks for oil sands facilities under TIER⁴



Estimating emissions from oil sands facilities

The four oil sands facilities we analyze represent a range of emissions intensities. Other facilities with similar emissions intensities should see similar impacts on their profitability from the implementation of the MOU. We analyze two projects with relatively low emissions intensities (Christina Lake and Kearl), one with an average emissions intensity (Firebag), and one that is on the higher end (Cold Lake) and faces high compliance costs in relation to its facility-specific benchmark. A metric called production weighted average emissions intensity (PWAEI) in Figure 6 puts the projects’ emissions performance in perspective by weighting each facility according to output.

⁴ The projects included in Figure 6 are a representative sample and do not include all operations in the Alberta oil sands. Based on estimated FSBs and emissions intensities where data is available from the [Government of Alberta's oilsands database](#) (emissions intensities are not cogen-adjusted). FSBs based on formulas prescribed in the [Standard for Developing Benchmarks v2.5](#) using baseline years 2013 to 2015 (if available) or alternate years to calibrate against reported true-up obligation data for the 2023 compliance period. Actual FSBs may vary based on confidential project-level data or director-authorized departures from standard baseline years. The 2023 HPBs for in-situ and mining oil sands facilities are established in [Ministerial Order 03/2024](#).

These project-specific emissions intensity differences necessitate project-specific analysis of carbon costs. We sourced historical oil sands data from the Government of Alberta's [Alberta Oil Sands Greenhouse Gas Emission Intensity Analysis](#). The dataset includes the following data for in-situ oil sands and mined oil sands projects from 2011 to 2023: monthly and annual production volumes, emissions, cogeneration emissions, heat and electricity generation (as applicable), cogeneration adjusted emissions, and cogeneration adjusted emissions intensity.

We compiled historical data from 2013 to 2023 for Cenovus Energy's Christina Lake facility, Suncor's Firebag facility, Imperial Oil's Kearl mine, and Imperial's Cold Lake facility.⁵ We forecast facility data for the years 2024 to 2035. We assume production increases by 2.7% annually and produce forecasts for cogen adjusted emissions intensity, cogen heat, and cogen electricity.⁶ We assume that emissions intensities decline at a conservative rate of 0.5% annually (see the appendix for more information on how this assumption affects results).

To estimate costs under TIER for each project, we compare the costs under an FSB and the HPB.⁷

We chose the lesser of the two costs for each facility. We also assume that companies maximize the credit usage limit at the forecasted credit price. Finally, companies can deduct their TIER costs from post-payout net-revenue royalties. We assume an estimated average post-payout royalty rate of 33%.

These are conservative estimates of carbon costs. Costs could be lower as projects make low-carbon investments over the next decade. We also do not account for credit generation that could result from significant emissions reduction projects in the sector, such as the Oil Sands Alliance's Pathways carbon capture project.

⁵ Emissions are determined through rearranging the formula specified in the [Government of Alberta's oilsands database](#) of Cogen Adjusted Emissions = Emissions - Cogen Emissions + Cogen Heat x 0.06299 tonnes per GJ heat.

⁶ We estimate two additional data points for 2013 to 2015 necessary for development of facility-specific benchmarks.

1) We determine emissions from the heat used in cogeneration through the multiplication of the heat generated by the cogeneration unit in GJ by the heat intensity value of 0.06299 tCO₂e/GJ. Imported and exported heat are additional variables, assumed as zero in the absence of data. The forecast for cogen-adjusted emissions is calculated based on each year's forecasted cogen-adjusted emissions intensity and production, and the forecast for total site emissions is calculated based on each year's forecasted cogen data.

2) We also accommodate emissions from the electricity used through the multiplication of the electricity generated on-site by the electricity high-performance benchmark for the baseline year (0.37 tCO₂e/MWh in 2022 and earlier). Imported and exported electricity are additional variables, assumed as zero in the absence of data.

See section 8.2.4 of the [Standard for Developing Benchmarks v2.5](#) for more information.

⁷ We calculate FSBs based on formulas prescribed in the [Standard for Developing Benchmarks v2.5](#) using baseline years 2013 to 2015 (if available) or alternate years to calibrate against reported true-up obligation data for the 2023 compliance period. Actual FSBs may vary based on confidential project-level data or director-authorized departures from standard baseline years.

These estimates also do not incorporate the potential impact of the Pathways project on emission reductions. Companies that are not participating in the project would have unchanged costs, continuing to comply with carbon pricing at market credit prices. Participating companies would likely face lower carbon costs, optimizing carbon credit use across their portfolios. See Box 1 below for more details on our general model assumptions and Box 2 below on how the Pathways project could impact the profitability of participating companies.

Results: Profitability growth from a pipeline outweighs carbon costs

Project-specific analysis

Using Commodity Context's financial model of Alberta oil sands operations, which includes facility-level royalty data, we estimate the future gross revenue, production, costs, royalties, and net operating cost of our four oil sands facilities. We assume that each facility sees annual production growth of 2.7%. Such growth is consistent with the MOU's commitment to build additional pipeline capacity of at least one million barrels per day to Canada's West Coast. To ascertain the increase in profitability, we assume that a new pipeline reduces the WCS-WTI differential from US\$18 per barrel to US\$13 per barrel.

In our figures below, "without-MOU profit" represents profitability in 2035 under a status quo scenario – Alberta carbon pricing still frozen at its current rate of C\$95 per tonne, no major new pipeline capacity, and therefore a WCS-WTI differential of US\$18 per barrel. In contrast, "with-MOU profit" represents a scenario where implementation of the MOU provisions leads to the construction of new pipeline capacity, and the price of TIER carbon credits rises to C\$130 per tonne by 2035.

A US\$1 per barrel change in the WCS differential has a magnified effect on underlying bitumen values. A barrel of WCS is about two-thirds bitumen and one-third diluent, which oil sands producers must purchase or produce elsewhere. If diluent prices remain constant while WCS prices change, the bitumen component of a WCS barrel must absorb 100% of that price fluctuation. The value of bitumen increases or decreases by about US\$1.50 per barrel for every US\$1 per barrel change in the WCS-WTI differential.

Box 1: Financial model assumptions

- Facility-level production is assumed to grow at a steady pace of 2.7% per year, which amounts to an oilsands-wide production increase of one million barrels per day through 2035.
- Operating costs: Emissions costs are estimated and removed from base operating costs, with the non-emissions operating costs then scaled with production.
- Capital costs are held flat through the forecast horizon.
- Facility-level gross revenue is modelled as the cleaned bitumen value (i.e., ex-diluent costs).
- Bitumen value: Bitumen Valuation Methodology (BVM) is simplified to assume the value of a barrel of cleaned bitumen is equivalent to two-thirds the value of a barrel of Western Canadian Select (WCS) dilbit, with the diluent portion valued at the price of WTI.
- Facility-level realized bitumen value: Each oilsands facility also had small differences between realized bitumen value (ex-diluent revenue/volume), which reflects both differences in bitumen grade and additional transportation cost differences; these differences are held flat.
- Exchange rate: All values are converted to CAD. We assumed a constant USD/CAD exchange rate of C\$1.38 in the scenarios.

Project TIER cost assumptions

- Emissions intensity: We assume emissions intensities decline by 0.5% annually between 2024 and 2035.
- Tightening: Benchmarks tighten at 2% annually until 2029 and 2030 when tightening is legislated as 4% for the oil sands. For 2031 to 2035, we assume tightening returns to 2% annually.
- Headline price:
 - Without the MOU, the headline carbon price remains flat at C\$95.
 - With the MOU, the headline carbon price increases by C\$5 per tonne annually until it reaches C\$145 in 2035.
- Credits: The credit usage limit remains at 90% from 2026 to 2035. We assume credits trade at a 10% discount to the headline price — C\$85 per tonne in 2035 without the MOU and C\$130 per tonne in 2035 with the MOU.⁸

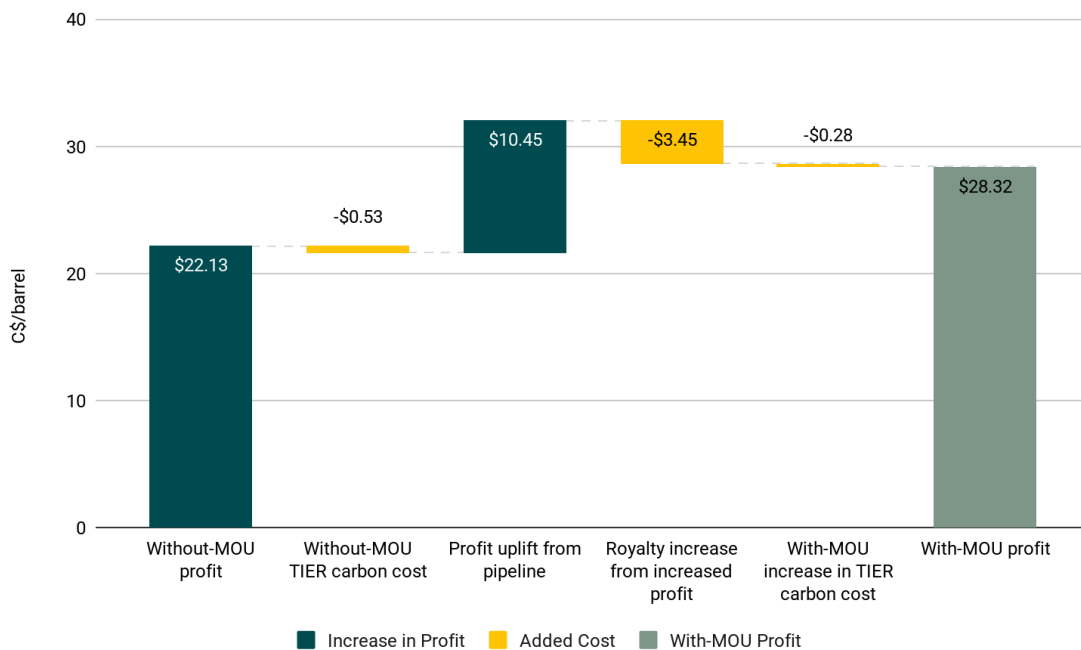
⁸ Strong carbon markets are required to reach a credit price of C\$130 per tonne. See Clean Prosperity's [Market Force](#) report.

Christina Lake

The addition of new pipeline capacity envisaged in the MOU results in a meaningful improvement in profitability for Christina Lake by 2035, even after accounting for higher royalties and carbon compliance costs. Without the MOU, profit is C\$21.60 per barrel, including TIER carbon costs of C\$0.53 per barrel. Following implementation of the MOU, improved pipeline access delivers a large impact, increasing profitability by 31% (C\$6.72 per barrel) as tighter WCS-WTI price differentials strengthen realized bitumen pricing. This upside is partially offset by a C\$3.45 per barrel increase in royalties as higher WCS prices and net revenues increase the project's royalty rate, along with a C\$0.28 per barrel increase in TIER carbon costs at a C\$130-per-tonne carbon credit price. Overall, profit rises to C\$28.32 per barrel, demonstrating that improved market access more than compensates for increased carbon costs.

Additional pipeline capacity not only increases per-barrel profits, but also increases total profits and royalties. Net profit increases by about C\$473 million in 2035 alone, relative to a scenario with no new pipeline capacity.

Figure 7: Increased profitability of Cenovus Energy's Christina Lake facility in 2035 following implementation of federal-Alberta MOU⁹



⁹ Totals in this and subsequent figures may not sum due to rounding.

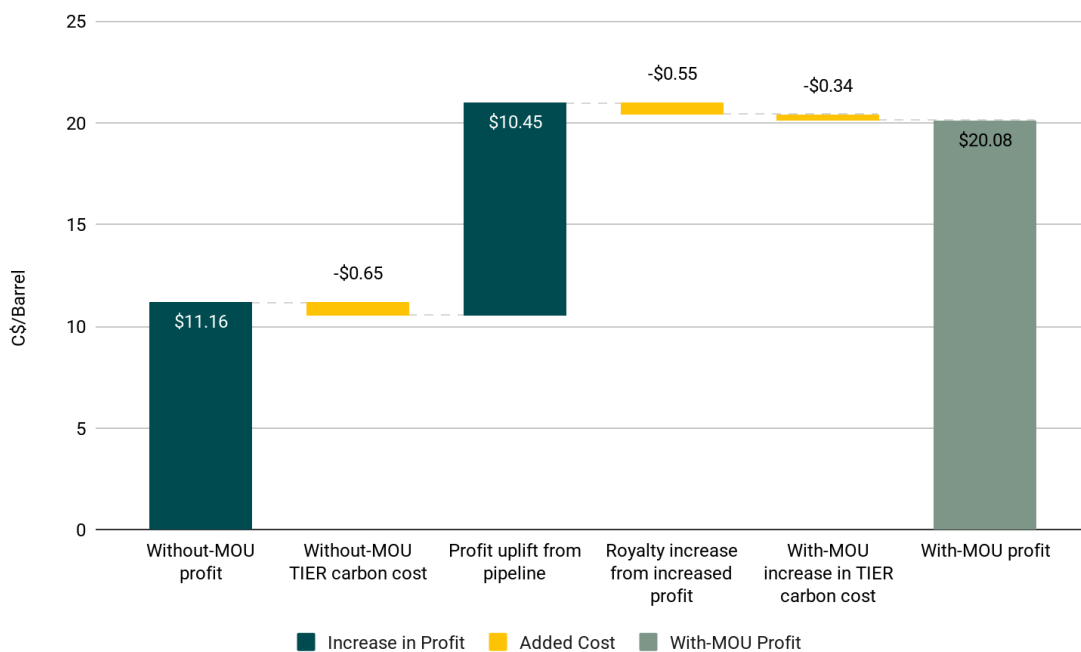
Kearl

New pipeline capacity that holds the WCS-WTI differential at C\$13 per barrel in 2035 also delivers a substantial uplift in profitability for a project like the Kearl mine. Without the MOU, profit is C\$10.51 per barrel, including TIER carbon costs of C\$0.65 per barrel.¹⁰ Under the MOU, additional pipeline capacity adds a significant C\$9.56 per barrel, nearly doubling baseline margins, inclusive of a C\$0.55 per barrel increase in royalties and a C\$0.34 per barrel increase in TIER carbon costs.

We project that Kearl will still be in its pre-payout period in 2035, meaning that revenue increases will have a more muted effect on the increase in royalties until the project recoups its investment. Additionally, as a mine it has lower operating margins. As a result, any increase in revenue from reductions in WCS-WTI differentials has a disproportionately higher impact on its profit growth, compared to older, post-payout facilities with higher margins. Although outside the scope of this analysis, it's also worth noting that higher profits will accelerate Kearl's transition to a post-payout royalty regime, resulting in higher fiscal returns for the province.

Overall, implementation of the MOU increases profitability to C\$20.08 per barrel, roughly a 90% improvement versus the without-MOU scenario of widening WCS-WTI price differentials. This highlights how enhanced market access is particularly transformative for lower-margin projects like Kearl.

Figure 8: Increased profitability of Imperial Oil's Kearl mine in 2035 following implementation of federal-Alberta MOU

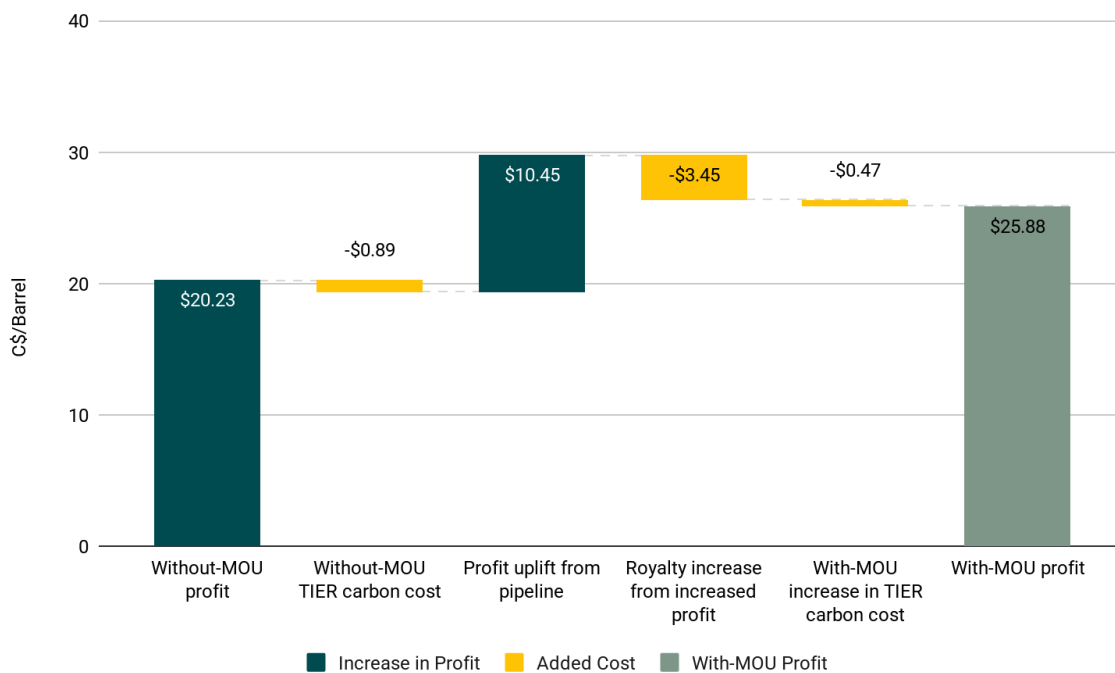


¹⁰ Unlike the other projects we analyze here that are in the post-payout royalty phase, and can deduct TIER credit costs as an allowable cost, we assume that TIER credit costs are not deductible for Kearl during its pre-payout royalty period.

Firebag

For Suncor’s Firebag facility in 2035, additional pipeline capacity added under the terms of the MOU produces a solid improvement in profitability, with gains clearly outweighing incremental carbon costs, albeit not as much as for Cenovus’ Christina Lake or Imperial’s Kearl mine. Without-MOU profit starts at C\$19.34 per barrel, partially reduced by C\$0.89 per barrel in TIER carbon costs. Improved pipeline access delivers a 34% increase in profitability (C\$6.54 per barrel), reflecting stronger revenues from tighter WCS-WTI differentials. This upside is partially offset by a C\$3.45 per barrel increase in royalties due to higher WCS prices and higher profits, along with a C\$0.47 per barrel increase in TIER carbon costs. Overall, profitability rises to C\$25.88 per barrel, demonstrating that for facilities with stable historical emissions intensities that can achieve reductions relative to their facility-specific benchmarks, improved market access remains a meaningful driver of long-term margin expansion, despite rising carbon costs.

Figure 9: Increased profitability of Suncor’s Firebag facility in 2035 following implementation of federal-Alberta MOU



Box 2: Impact of the Pathways project on profitability

The Oil Sands Alliance's [Pathways project](#) is a large-scale carbon capture, transport, and storage project in Alberta's oil sands. Phase 1 is a C\$20-billion system proposed to capture up to 12 MtCO₂ per year from oil sands facilities.

Our analysis elsewhere in the report does not consider the potential impact of participation in the Pathways project on the profitability of our four oil sands facilities, as the exact cost of the project will differ for each facility. All four facilities are planned to participate in Pathways. Construction of the Pathways project is a commitment in the federal-Alberta MOU, but it depends on governments creating certainty about the future value of carbon credits – also a commitment in the MOU.

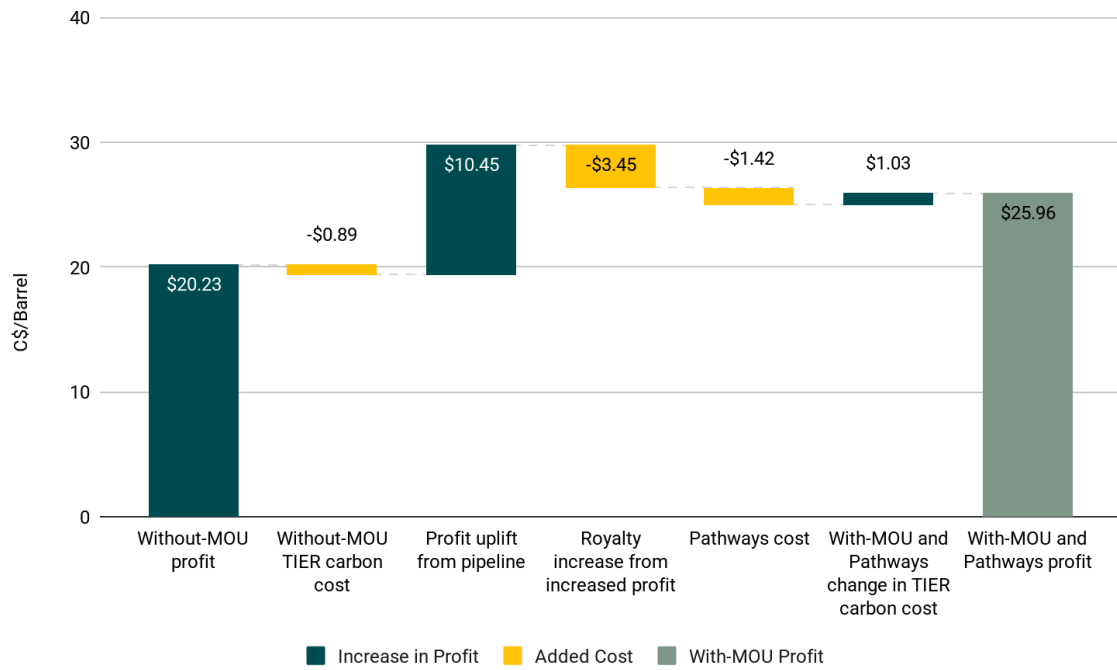
We repeated our analysis of Suncor's Firebag facility, this time incorporating the additional costs and carbon-credit generation that would result from Pathways.¹¹

Under an MOU scenario with a minimum effective carbon credit price of C\$130 per tonne and additional pipeline capacity, we estimate that also joining the Pathways project would reduce Firebag's TIER carbon costs. Even with the cost of building and operating carbon capture infrastructure, the facility would still be more profitable in 2035, thanks to the implementation of the MOU, than it would be without it.

In our estimates, the Firebag project is also slightly more profitable by taking on the Pathways costs instead of paying the full TIER costs we estimate, but the exact results would be highly dependent on the Pathway project costs. Not all oil sands facilities would be impacted in the same way by participation in Pathways. The impact on a facility's profitability will depend on current and future emissions relative to the facility's benchmark.

¹¹ Based on [Clean Prosperity modelling](#). Cost estimates are inclusive of the federal carbon capture, utilization, and storage investment tax credit, the Alberta Carbon Capture Incentive Program, and the deduction of TIER costs when calculating post-payout royalties. Costs reflect the low end of the modelled range, on the basis that the project would only participate in Pathways if the per-tonne cost of carbon capture is below the price of carbon credits. Applying the median cost value instead would also yield total profits materially equivalent to those earned without participation in Pathways. We assume that Firebag captures 24% of its annual emissions (equivalent to 1.88 MtCO₂ in 2035), based on its emissions-weighted share of total projected Pathways capture volume, and that all carbon credits generated are retired and/or sold in the year they are generated (not banked).

Figure: Increased profitability of Suncor's Firebag facility in 2035 following implementation of federal-Alberta MOU and Pathways Phase 1



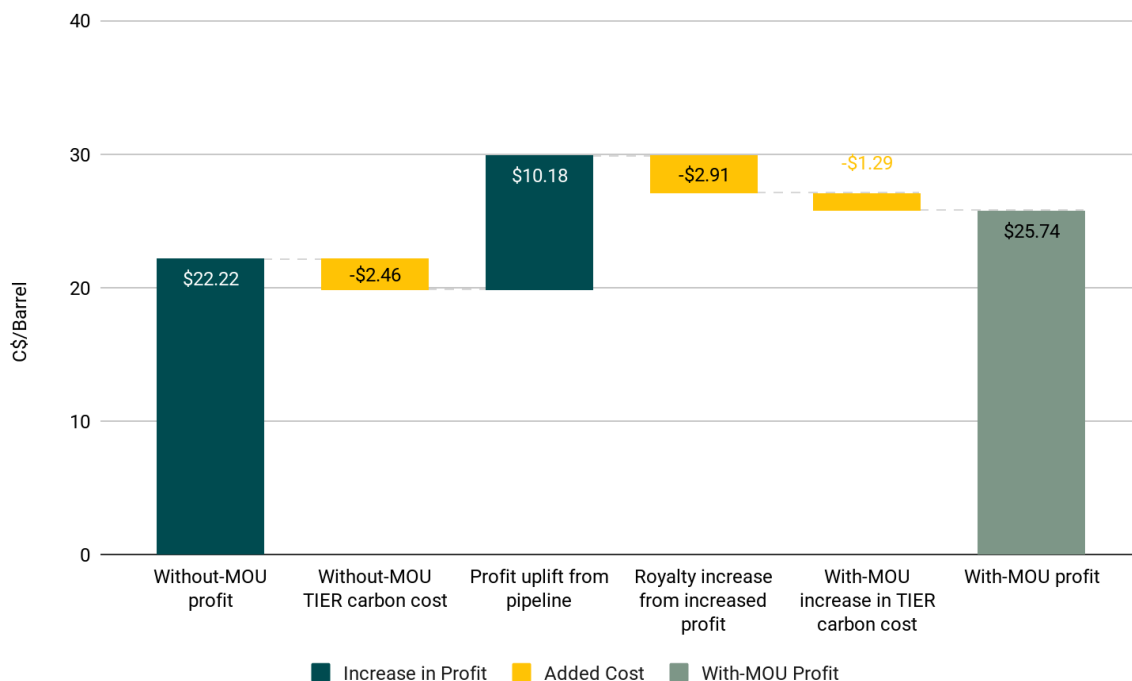
Cold Lake

Imperial's Cold Lake has increased its emissions intensity since its benchmark years.¹² As a result, we project that the facility will incur higher TIER costs in 2035 compared to sites that have decreased their emissions since their facility benchmark was set. This is a typical dynamic under TIER, in which sites compete against their own previous performance.

For Cold Lake in 2035, implementation of the MOU delivers a slightly more modest net improvement in profitability. Without the MOU, profit is C\$19.76 per barrel, net of C\$2.46 in TIER carbon costs. Tighter WCS-WTI differentials due to increased pipeline access increase profitability by 30% (C\$5.98 per barrel). This pricing uplift is partially eroded by a C\$2.91 per barrel increase in royalties due to higher profits. Under the MOU, Cold Lake incurs the highest increase in carbon costs in our analysis – C\$1.29 per barrel at a C\$130 per tonne carbon credit price. This reflects the fact that Cold Lake's emissions intensity increased since its benchmark years.

Overall, Cold Lake's profit rises to C\$25.74 per barrel, highlighting how facilities with a history of deteriorating emissions performance are still likely to be financially better off, net of a C\$5 reduction in the WCS-WTI differential and higher TIER prices.

Figure 10: Increased profitability of Imperial Oil's Cold Lake facility in 2035 following implementation of federal-Alberta MOU



¹² Cold Lake began as a cyclic steam stimulation project that began commercial operations in the 1980s. As reservoirs age, oil-to-steam ratios typically decline, requiring more steam per barrel to maintain production. New developments use SA-SAGD to improve efficiency.

Future value analysis

The above analysis shows that in 2035, the profitability uplift from improved egress more than offsets the higher cost of carbon pricing for four representative oil sands projects with varying emissions intensities and royalty periods.

The profitability benefits of new pipeline capacity are a decade away, but the costs of higher carbon pricing will be borne in the near term. Do those future benefits and present costs present a compelling investment case now?

One way to address this question is to calculate the present value of carbon costs and compare that to the present value of the reduced WCS-WTI price differentials from new pipeline capacity. We determined the total per-barrel cost of the TIER program between 2027 and our assumed 2035 in-service date of a new one-million-barrel-per-day pipeline, discounted to present.

We show two versions of the cost of TIER. The first is the total cost of the full TIER program at the carbon price outlined in the MOU. A second version shows just the incremental cost of increasing carbon prices from the current level of C\$95 per tonne. We then divided that cost between the discounted future increases in per-barrel profit once the pipeline is in operation in 2035. That creates a measure of how many years of pipeline operation each project needs to recover the higher TIER costs it incurred before the pipeline entered service. This measure of how many years of higher profits are required from any new pipeline reflects the inherent uncertainty that a new pipeline may not ever result in a lower WCS-WTI differential. If it does, how long it provides that higher return is a measure of its value. The total net profit with the MOU in place (the last column of Table 1) is the net present value of the increased annual profits from 2035 to 2050 if the pipeline provides continuous improvement in pricing over this period, minus the net present value of the incremental TIER costs above C\$95 per tonne between 2027 and 2035.

We used the same assumptions about TIER costs as in the analysis above. We also calculated the discounted total net additional profit after 15 years, assuming the WCS-WTI differential remains at US\$13 instead of US\$18, and that production and prices remain flat between 2035 and 2050. We used a 10% discount rate and the same assumptions about the TIER cost trajectory outlined above through to 2035. We assumed that emissions intensities remained flat after 2035, and that headline TIER prices remained frozen at C\$145 after that date. Importantly, for these calculations of the net present value of total profit, we assume no increase in oil prices until a new pipeline becomes operational in 2035.

For projects like Christina Lake, Kearl or Firebag, the increased long-term profitability that results from new pipeline capacity pays off the increased near-term costs of a C\$130/tonne TIER credit price in approximately one year or less, and total TIER costs in one to two years. Each of these projects also sees a significant overall increase in profit assuming that WCS-WTI price differentials remain constrained for 15 years. We also assume that the Kearl facility stays in the pre-payout royalty regime

for this analysis. However, it will likely move to a post-payout regime over this period, reducing the project profitability but improving the fiscal returns for Alberta (as we discuss further below).

This one year payback could materialize in a number of ways. Even if an increase in pipeline capacity to the U.S. lowers transport costs, a new pipeline to the West Coast offers egress diversification that could support producer profits in the event that exports to the U.S. are in any way constrained. The optionality value of a new pipeline to the Pacific Ocean underpins the economic return potential of the MOU framework.

Unlike the other three projects, Imperial's Cold Lake facility faces substantial TIER costs between now and 2035, assuming it only slightly reduces emissions. That project only recovers its total 2027-2035 TIER costs after about eight years of higher profits from a new pipeline, and incremental TIER costs from the MOU in about two years.

Looking at the last column of Table 1, all projects see a substantial increase in net profits from the MOU. The net present value of their increased profits, assuming 15 years of lower WCS-WTI differentials, is substantially larger than the net present value of increased TIER costs under the MOU. The Christina Lake and Firebag projects both see an increase of around C\$2.6 billion in the net present value of their profits. Kearl's profits, assuming it stayed under the pre-payout royalty framework, would increase by a net present value of C\$4.6 billion. For Cold Lake, the net present value of increased profits is C\$1.3 billion.

Table 1: Net present value (NPV) of near-term TIER costs and long-term increased profitability

Project	Total TIER cost, 2027 to 2035, NPV (C\$ million)	Total TIER cost in 2035 (C\$/barrel)	MOU TIER cost increase, NPV (C\$ million)	Post-MOU increased profit per barrel	Annual production in 2035 (million barrels)	Annual profit increase, 2035 through 2050 (C\$ million)	Net profit, 2027 to 2050, NPV (C\$ million)
Christina Lake	\$240	\$0.83	\$63	\$6.72	111	\$747	\$2,662
Kearl	\$349	\$1.01	\$92	\$9.56	133	\$1,274	\$4,559
Firebag	\$481	\$1.39	\$120	\$6.54	112	\$730	\$2,546
Cold Lake	\$989	\$3.84	\$232	\$5.98	69	\$411	\$1,268
Four project total	\$2,060	\$1.52	\$507	\$7.44	425	\$3,162	\$11,034

Note: Per barrel amounts are production weighted-totals.

An additional consideration for the province of Alberta is the increased future value of royalties. Table 2 (below) shows the increase in per-barrel royalties as a result of the implementation of the MOU, and the increase in total royalties paid between 2035 and 2050. We assume that 2035 production levels remain flat through 2050.¹³

All projects see a significant increase in total royalties paid to the province. Given their current royalty status, these four projects combined would pay roughly C\$950 million more in royalties to the province if the WCS-WTI differential is reduced by US\$5 per barrel. The net present value of the increase in royalties from these four projects from 2035 to 2050 is approximately C\$3.2 billion to C\$4.6 billion.¹⁴ The companies that own the projects would likely also pay more in provincial and federal corporate income taxes, though this is outside the scope of our project-level analysis.

¹³ Royalties are calculated net of TIER costs for post-payout projects. We deduct the net present value of foregone royalties between 2027 and 2035, as a result of higher TIER costs under the MOU, in our calculation of the total increase in royalties between 2035 and 2050.

¹⁴ Kearl is likely to enter its post-payout royalty period in the mid-2030s. This would increase the net present value of the province's 2035-2050 royalties by about C\$1.4 billion (and reduce Imperial Oil's profits from the project).

Table 2: Royalty increase from increased profitability, 2027-2050

Project	Total royalty increase, 2035-2050 (C\$/barrel)	Increased annual royalties, 2035-2050 (C\$ million)	Royalty increase, 2035-2050, NPV (C\$ million)
Christina Lake	\$3.31	\$368	\$1,312
Kearl	\$0.55	\$73	\$233
Firebag	\$3.22	\$360	\$1,254
Cold Lake	\$2.27	\$156	\$456
Four project total	\$2.25	\$957	\$3,254

Note: Per barrel amounts are production weighted-totals.

Conclusion

Analysis shows that the profitability gains from securing new pipeline capacity – which significantly reduces the WCS-WTI price differential – outweigh the increased compliance costs associated with strengthening Alberta's TIER carbon market to achieve a market price of C\$130 per tonne by 2035. Even for high-emission oil sands facilities, increased market access is the dominant factor, translating into a potential net profit increase that strongly supports the grand bargain articulated in the federal-Alberta MOU. An aggressive path to decarbonization can be paired with, and financially supported by, strategic growth in market access for the oil sands sector.

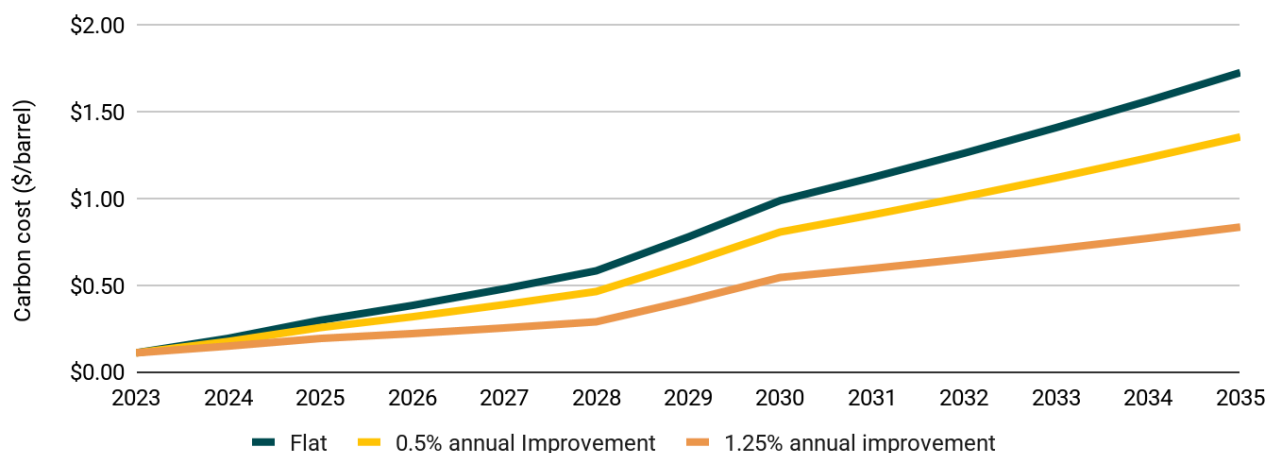


Appendix

We apply conservative assumptions about future emissions intensity reductions at oil sands projects. From [2012 to 2023](#), the emissions intensity of in-situ projects in Alberta decreased by 13%, approximately 1.25% annually, and integrated mining emissions intensity declined by 25.5%. If this trajectory continues, forecasted carbon costs under TIER would be lower than our conservative estimates.

Looking at the effect of this assumption for our average-intensity facility, Suncor's Firebag, a 1.25% decline in emissions intensity annually would lower the project's TIER carbon costs in 2035 from \$1.72¹⁵ per barrel – assuming that emissions intensity stays flat – to \$0.83 per barrel, accounting for credit use and royalty savings. This is equal to carbon cost savings of \$102 million in 2035 alone. We choose to model 0.5% annual emissions intensity reductions to reflect the sector's historical trends, while being conservative in our estimates.

Figure A1: Carbon costs for Firebag



We also note that these assumptions about emissions intensity will not be independent of credit prices. Higher credit prices incentivize the adoption of new technologies and practices to reduce emissions and mitigate carbon costs. These dynamics are particularly relevant over extended time horizons. However, estimating a dynamic relationship between credit prices and facilities' emissions intensities is outside the scope of this analysis.

¹⁵ All currency amounts in the Appendix are in Canadian dollars.

In the following tables we show the sensitivity of carbon costs and profitability estimates at our four facilities to changes in assumptions about emissions intensity reductions.

Table A1: Sensitivity analysis – change in costs and profitability in 2035 dependent on different emissions intensity forecasts from 2024 to 2035 at Christina Lake (\$/barrel)

Scenario	With-MOU increase in TIER carbon cost	Net increase in with-MOU profit
Flat emissions intensity	\$0.36	\$6.64
0.5% annual emissions intensity improvement	\$0.28	\$6.72
1.25% annual emissions intensity improvement	\$0.17	\$6.84

Table A2: Sensitivity analysis – change in costs and profitability in 2035 dependent on different emissions intensity forecasts from 2024 to 2035 at Kearl (\$/barrel)

Scenario	With-MOU increase in TIER carbon cost	Net increase in with-MOU profit
Flat emissions intensity	\$0.42	\$9.48
0.5% annual emissions intensity improvement	\$0.34	\$9.56
1.25% annual emissions intensity improvement	\$0.22	\$9.68

Table A3: Sensitivity analysis – change in costs and profitability in 2035 dependent on different emissions intensity forecasts from 2024 to 2035 at Firebag (\$/barrel)

Scenario	With-MOU increase in TIER carbon cost	Net increase in with-MOU profit
Flat emissions intensity	\$0.59	\$6.41
0.5% annual emissions intensity improvement	\$0.47	\$6.54
1.25% annual emissions intensity improvement	\$0.29	\$6.72

Table A4: Sensitivity analysis – change in costs and profitability in 2035 dependent on different emissions intensity forecasts from 2024 to 2035 at Cold Lake (\$/barrel)

Scenario	With-MOU increase in TIER carbon cost	Net increase in with-MOU profit
Flat emissions intensity	\$1.50	\$5.77
0.5% annual emissions intensity improvement	\$1.29	\$5.98
1.25% annual emissions intensity improvement	\$1.01	\$6.26