ECONOMIC VIEWPOINT

West Coast Oil Pipeline: Is the Next Barrel Worth the Price?

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HIGHLIGHTS

- The proposed West Coast Oil Pipeline (WCOP) would move 1 million barrels per day (b/d) of Alberta heavy crude to a marine terminal in southern British Columbia, increasing oil exports to Asian markets and reducing Canada's dependence on the US market. Oil demand is expected to keep growing in Asia, but demand for Canadian barrels specifically remains uncertain.
- WCOP could be a net positive, but only if costs are contained. Alberta's current pipeline cost estimate of $35B to $44B is still early-stage and excludes financing costs. Canada's recent infrastructure record—especially the Trans Mountain Expansion Project (TMX)—shows how delays, permitting complexity and financing during construction risk undermining the economics of an otherwise strategically valuable project.
- The new pipeline could reduce bottleneck risk, but any narrowing of the differential between Western Canadian Select (WCS) and West Texas Intermediate (WTI) would likely be temporary. Its main benefit lies in increasing production and exports, which would require a major increase in capital investment, effectively reversing the industry's current focus on capital discipline and shareholder returns. Canadian producers have the cash to fund production growth, but new pipeline capacity alone will not be enough to trigger a large investment wave.
- The project could deliver economic benefits, but current estimates of those benefits should be taken with a grain of salt. Economic gains from construction are temporary and sensitive to domestic content, labour availability and input costs, while the benefit from operations is better understood as a higher level of GDP, not a recurring annual growth boost.
- Government royalties and tax receipts help justify public funding, especially given Alberta's recurring bitumen royalty upside and Ottawa's broader tax gains. But cost overruns are also an important consideration in large infrastructure projects. A project structure that aligns risks and returns among governments, producers, shippers, Indigenous partners and external investors helps support long-term viability and broad stakeholder participation.

The WCOP proposal has grabbed national attention, promising new market access and tens of billions of dollars in potential energy investment. But a bigger question looms behind the headlines: does the project make economic sense?

This report assesses the economic case and sets aside the broader political debate around the proposal. Is there enough demand for Canadian heavy oil? Is another pipeline needed? Can the project be built at a cost that keeps pipeline tolls competitive? And if governments are asked to fund it, what are the economic and fiscal upsides, downsides and risk-sharing implications?

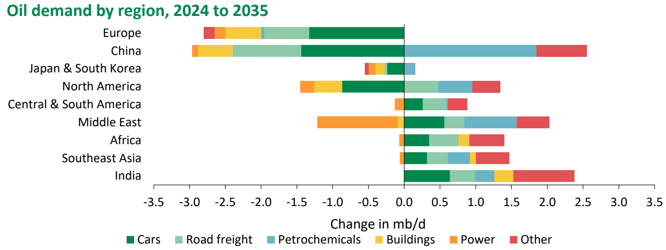
Is There Enough Demand for Canadian Heavy Oil?

WCOP would primarily serve Asian markets. This focus makes economic sense because the region is expected to drive most of the growth in global oil demand. The International Energy Agency (IEA) expects demand in Asia[1] and the Middle East to increase by nearly 8 million barrels per day (mb/d) by 2035, while consumption in the rest of the world declines by about 2 mb/d (graph 1 on page 2). This divergence reflects continued industrialization, urbanization, population

[1] The forecast accounts for the rapid penetration of electric vehicles in China.

Graph 1
Asia Is Expected to Experience the Strongest Demand Growth

Oil demand by region, 2024 to 2035



International Energy Agency and Desjardin Economic Studies

growth and rising incomes in Asian economies, with oil demand in the region expected to increase by 13 mb/d by 2050. In contrast, North America and Europe are mature markets where electric vehicles and the shift toward lower-carbon energy are expected to reduce oil consumption.

WCOP could also help oil-importing countries diversify their supplies. Recent disruptions around the Strait of Hormuz have highlighted the risks associated with relying on a limited number of transportation routes.

Asia is a major refining hub, accounting for 36% of global capacity. China and India have complex refineries capable of processing Canadian heavy crude and already import Canadian barrels. However, this does not guarantee demand for WCOP's full 1.0 mb/d capacity, as Canadian crude would still need to compete on price, quality, reliability and transportation costs.

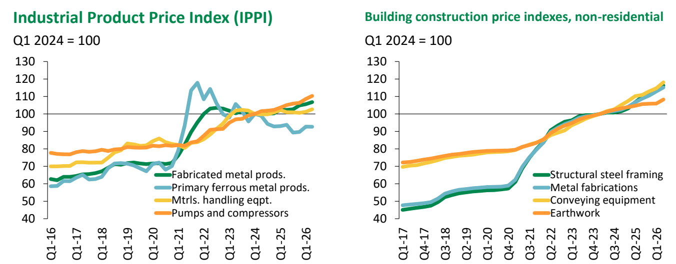
A Larger Pipe in a Pricier World

Cost estimates for WCOP may be optimistic at this stage. Alberta's $35.2B to $43.7B capital-cost range includes contingencies, but the project remains early in development, with final routing, terminal design, permitting and consultation outcomes still unresolved. Importantly, the estimate excludes financing costs.

A comparison with TMX suggests Alberta's estimate assumes WCOP can be built much more cost-efficiently. TMX ultimately cost $28.6B to build, before financing costs. Measured by construction cost per barrel of added capacity, WCOP would need to deliver roughly 20% better capital efficiency than TMX.[2] Corridor reuse could help support this cost saving, since the proposed route would largely parallel existing Trans Mountain infrastructure.

Corridor reuse should reduce some routing, land and regulatory risk, but it does not eliminate construction-cost risk. Construction and labour costs have risen significantly since the pandemic and remain well above pre-pandemic levels, contributing to TMX's cost overruns. Since TMX was completed in 2024, non-residential construction costs have increased by more than 9%, and they are up more than 45% from pre-pandemic levels (graph 2, right), with notable increases in pipeline-related categories such as conveying equipment, structural steel framing and metal fabrications (graph 2, left).

Graph 2
The New Pipeline Would Be Built in a Higher Cost Environment



Note: All series indexed to 100 in Q1 2024, when TMX was completed.
Statistics Canada and Desjardins Economic Studies

Scale is another reason the current cost estimate warrants caution. WCOP's physical scope is meaningfully larger than TMX's: about 40% more pipe with a larger diameter, nearly four times the pumping horsepower and almost three times the working storage capacity. In terms of transporting the conveyed oil, WCOP would load onto Very Large Crude Carriers (VLCCs) rather than Aframax tankers, increasing vessel capacity from roughly 750,000 barrels to about 2M barrels per ship.[3] That scale would likely improve unit economics if the project is delivered on budget, but it would also increase exposure to the same cost pressures that challenged TMX.

The all-in cost of WCOP could be several billion dollars higher after including financing costs. TMX provides a useful cautionary example: by year-end 2024, it had accumulated $5.1B of financing costs on top of its construction costs. Financing costs also rose materially as the project was delayed. Applying a TMX-like carrying-cost ratio of roughly 15% to WCOP's current

[2] TMX ultimately cost $28.6B to build and $5.1B to finance. Using construction costs only, that translates to roughly $57,000 per barrel per day of added capacity in today's dollars. By comparison, WCOP's high-end estimate implies about $43,700 per barrel per day, meaning WCOP would need to deliver roughly 20% better capital efficiency than TMX before financing costs are included.

[3] According to the Major Projects Office, the WCOP proposal includes an oil delivery terminal and marine facility at Roberts Bank as part of the pipeline project. This is distinct from the broader Roberts Bank/Port of Vancouver expansion, for which the Government of Canada has committed support toward a $10B capacity expansion.

estimate would imply an additional $5B to $7B in financing costs before any allowance for schedule delays or design changes.

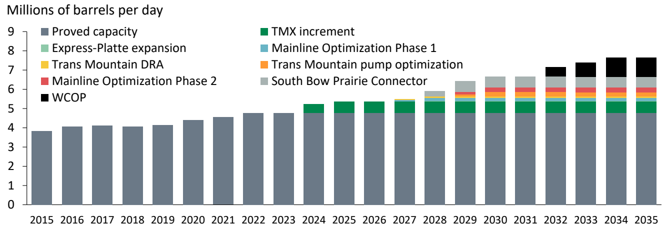
The timeline also looks ambitious. Alberta is targeting national-interest listing by October 1, 2026, construction permissions as early as September 1, 2027, and completion in 2032 to 2034. That is an aggressive timeline for a project whose route, terminal design, permitting requirements and Indigenous consultation outcomes are still unknown.

What Other Projects Are in the Pipeline?

WCOP is not the only pipeline project under consideration, and it is the least advanced of the proposed pipelines. Three other projects are either under construction or well advanced. Together, the Express-Platte expansion, the Trans Mountain Drag Reducing Agent (DRA) Project and Phase 1 of Enbridge's Mainline Optimization Program are expected to add 270,000 b/d of pipeline capacity by the end of 2027 (graph 3).

Graph 3
If All Pipeline Projects Move Forward, Canadian Capacity Would Increase by 40%
Pipeline capacity coming out of the Canada Sedimentary Basin

Millions of barrels per day



WCOP: West Coast Oil Pipeline
Canada Energy Regulator and Desjardins Economic Studies

Additional projects could add further capacity, including the Trans Mountain Mainline pump optimization, phase 2 of Enbridge's Mainline Optimization and South Bow's Prairie Connector project,[4] although these still face regulatory and financing hurdles. Together, these projects would add double the capacity of TMX for half its cost. Unlike WCOP, these projects would expand capacity by optimizing existing infrastructure rather than building a new pipeline, which generally requires less capital and can bring capacity online more quickly.

Donald Trump also mentioned wanting to resurrect the Keystone XL project, but the South Bow Prairies Connector is its natural successor. Therefore, we only consider the latter in our analysis.

Competitive Toll, Thin Margin for Error

A new pipeline, such as the proposed WCOP, would likely operate for more than 50 years. However, its cost structure would reflect today's high construction and financing costs. As a result, tolls would likely be higher than on older lines, where much of the initial investment has already been recovered. While higher oil prices would help preserve producers' margins and support upstream investment in the face of higher tolls, they are not a prerequisite for a new pipeline to be economically viable. The project's financial viability would ultimately depend on factors such as construction costs, financing conditions, long-term shipping commitments, expected production growth and the value of improved access to global markets.

With the current cost and construction schedule, WCOP could remain economically viable at a competitive toll. Alberta's estimated capital-cost range implies a break-even toll of roughly $10.50 to $12.80/bbl at an illustrative 6% discount rate (table 1A). The challenge is that this leaves limited room for cost escalation or schedule delays. If the project experiences TMX-style cost creep, keeping tolls near $11/bbl could require governments or equity investors to absorb a meaningful share of overruns, potentially in the $5B to $30B range depending on the final cost and required return (table 1B). A higher

Table 1A
Hypothetical Break-Even Toll of WCOP

	Discount rate		
Capital cost	4%	6%	8%
$35.2B	$7.57/bbl	$10.49/bbl	$14.16/bbl
$43.7B	$9.20/bbl	$12.81/bbl	$17.36/bbl
$50B	$10.41/bbl	$14.54/bbl	$19.73/bbl
$60B	$12.32/bbl	$17.27/bbl	$23.49/bbl
$70B	$14.23/bbl	$20.00/bbl	$27.25/bbl

Break-even tolls are calculated using a discounted cash flow framework assuming a six-year construction period, seven-year ramp-up to 950 kb/d, steady-state utilization through 2070 and $250M/year of operating costs.
Desjardins Economic Studies

Table 1B
Net Present Value of WCOP at $11/bbl Toll

	Discount rate		
Capital cost	4%	6%	8%
$35.2B	$15.6B	$1.5B	-$6.5B
$43.7B	$8.2B	-$5.4B	-$13.0B
$50B	$2.7B	-$10.6B	-$17.9B
$60B	-$6.0B	-$18.8B	-$25.6B
$70B	-$14.8B	-$27.0B	-$33.3B

Net present values are calculated using a discounted cash flow framework assuming a six-year construction period, seven-year ramp-up to 950 kb/d, steady-state utilization through 2070 and $250M/year of operating costs.
Desjardins Economic Studies

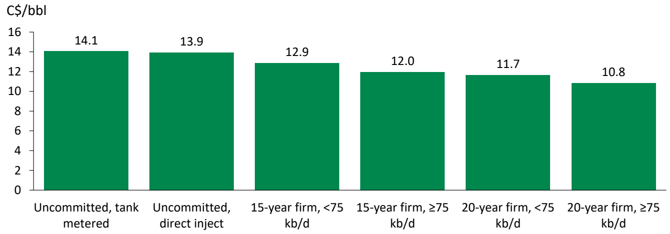
[4] The South Bow Prairie Connector project is commercially advanced and supported by 20-year binding shipping commitments, but financing, regulatory approvals and a final investment decision remain outstanding.

required return, such as the 8% discount rate used by the Parliamentary Budget Officer in its TMX valuation, would push break-even tolls higher.

The alternative would be to pass more of the overrun cost on to shippers, but TMX shows the commercial risk of that approach. TMX currently charges roughly $11/bbl for contracted shippers and about $14/bbl for spot movements[5] (graph 4), reflecting a sharp increase in tolls as project costs rose.[6] While roughly 70% of TMX's overruns were expected to be borne by government-owned Trans Mountain, the toll increase was large enough to trigger shipper resistance. The result was a prolonged tolling dispute that lasted roughly two years before a negotiated settlement was reached in July 2026. Moreover, higher tolls can weaken utilization, delay contracting and complicate asset valuation when selling.

Graph 4
Trans Mountain's Cost Overruns Were Partly Passed On to Shippers Through Higher Tolls

Published Trans Mountain Pipeline toll*



* Interim Tariff No. 123, effective May 1, 2026.
Canada Energy Regulator and Desjardins Economic Studies

WCOP could improve export economics by loading oil onto larger tankers. While TMX's Westridge terminal uses Aframax-scale vessels that carry roughly 750,000 barrels, Roberts Bank could be designed for VLCCs, which carry about 2M barrels. Larger shipments would reduce the freight cost per barrel into Asian markets, with potential savings of roughly US$2/bbl compared with Aframax-only shipping.[7]

Impact on the WCS Spread: Likely No Discount, Just Stable Prices

One of the main arguments in favour of WCOP is that additional export capacity would narrow the WCS–WTI differential. However, this effect is unlikely to be permanent because the differential reflects three factors: crude quality, transportation costs and pipeline congestion.

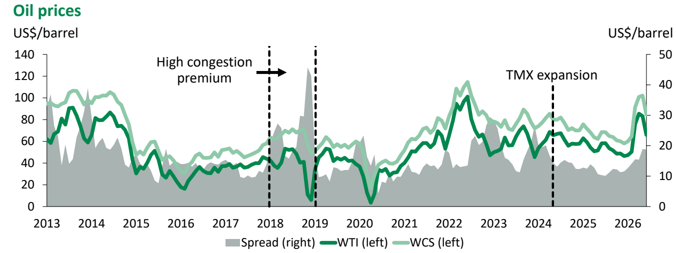
The quality discount is structural. Alberta's heavy crude is more difficult and costly to refine than lighter crude such as WTI. This discount can vary with market conditions, but it will not disappear.

Transportation costs are also unavoidable. Access to Asia would diversify Canada's customer base, but the longer distance and higher marine shipping costs could offset part of the price advantage obtained in those markets.

The pipeline congestion premium is the only factor directly addressed by additional pipeline capacity. When pipelines are full, producers must compete for limited space and discount their barrels to prevent inventories from building up. This occurred in 2018, when strong production and insufficient capacity pushed the WCS–WTI differential above US$40 per barrel (graph 5). Canadian producers have not forgotten that costly lesson.

Graph 5
The Congestion Premium Can Widen the Spread Significantly

Oil prices



WTI: West Texas Intermediate; WCS: Western Canadian Select
Bloomberg and Desjardins Economic Studies

Today, the congestion premium remains marginal because Canada's major pipelines, including Trans Mountain, are operating at or below capacity. As long as Canadian producers remain disciplined and do not oversupply the pipeline network, the monthly differential should generally remain between US$10 and US$20 per barrel. Additional capacity could initially narrow the spread further as pipeline operators and refiners compete for barrels.

However, producers are unlikely to leave that capacity unused. Higher production and exports would gradually fill the new

[5] Spot movements refer to barrels shipped without a long-term capacity commitment and are priced under TMX's uncommitted service toll schedule.

[6] TMX's benchmark fixed toll roughly doubled under its approved cost-recovery framework. Under that framework, certain "uncapped" costs could be recovered from shippers through tolls, while capped cost overruns above the approved threshold were absorbed by the pipeline operator. Uncapped costs rose from $1.8B in the 2017 estimate to $9.1B in the final accounting, increasing the benchmark fixed toll from $5.76/bbl to $10.88/bbl.

[7] Recent Vancouver–China Aframax freight rates have been around US$5 to US$6/bbl, while ship-to-ship transfer economics suggest moving barrels onto a VLCC near Southern California could reduce the cost to roughly US$4/bbl, including transfer costs. Direct VLCC loading from Roberts Bank could therefore save on the order of US$2/bbl versus Aframax-only shipping.

pipeline, causing the initial price benefit to fade. This is what happened after TMX entered service: the differential narrowed before returning to its historical range. WCOP could therefore reduce the risk of another severe price dislocation, but it would not necessarily deliver a permanent improvement in WCS prices.

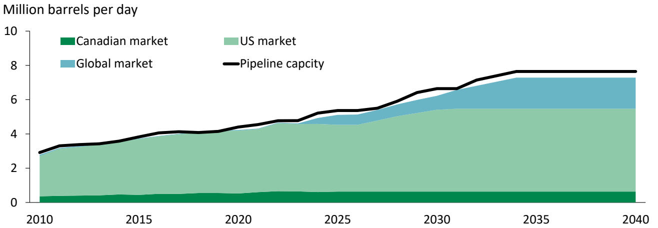
Market Access Could Reignite Upstream Production and Capital Spending

As new pipeline capacity becomes available, oil production generally begins to increase in the year before a project enters service. Production then continues to ramp up as the new capacity is absorbed, with pipelines expected to reach a 95% utilization rate (the industry standard) within two years of becoming operational.

Building on the Canada Energy Regulator's (CER) Canada's Energy Future 2026 outlook, and adding assumed capacity from Trans Mountain optimization, Enbridge Mainline Optimization Phase 2, the South Bow Prairie Connector and WCOP, we estimate that oil production in the Western Canada Sedimentary Basin[8] could rise from 5.1 mb/d in 2025 to approximately 7.2 mb/d by 2035, an increase of roughly 40% (graph 6). Most of the additional production would be directed toward global markets. Growth in capacity serving the US would be more modest and would come mainly from the South Bow Prairie Connector. This is WCOP's main potential benefit: increasing production and exports, rather than permanently narrowing the WTI–WCS spread.

Graph 6
Most Additional Production Would Be Directed Toward Global Markets

Canadian production available for exports by destination*



* Assuming all projects are realized.
Canada Energy Regulator and Desjardins Economic studies

[8] Production and pipeline capacity projections are based on the Canada Energy Regulator's Canada's Energy Future 2026 outlook, supplemented by assumed additions from Trans Mountain optimization projects, Enbridge Mainline Optimization Phase 2 and the proposed WCOP. New capacity is assumed to reach a long-run utilization rate of 95%, with production responding gradually beginning one year prior to project start-up and reaching full utilization over three years.

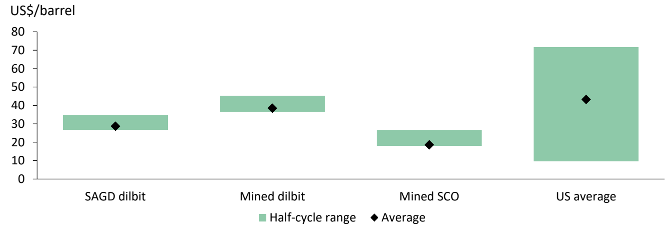
Feasible, but at What Price?

To answer this question, two thresholds must be understood: the price at which using WCOP becomes profitable and the price needed to encourage producers to expand output and fill the pipeline.

Canadian producers' break-even prices[9], generally measured against WTI, range from approximately US$18 to US$45 per barrel and already include average transportation costs (graph 7). That said, the bulk of Canadian production volumes sits closer to a US$40 per barrel break-even. Adding the difference between existing pipeline tolls and expected WCOP tolls raises this range to roughly US$23 to US$60, depending on the project's final cost. Although this is a wide range, it's less concerning because tolls can be structured to remain competitive for shippers while providing a reasonable return to pipeline investors.

Graph 7
Canadian Oil Producers Benefit from Low Break-Even Prices

Canadian and US half-cycle break-even cost*



* Half-cycle break-even costs include operating expenses, diluent and adjustments for transportation and crude quality to make the measure comparable with WTI.
S&P Global, Dallas Fed Energy Survey and Desjardins Economic Studies

The second threshold is more difficult to estimate. Investment decisions for a pipeline entering service as early as 2032 would likely be made between 2028 and 2031. In a balanced oil market and stable global economy, new production could require an average WTI price of approximately US$75 or more per barrel to recover construction and operating costs. While plausible, this price level is on the higher end of the long-term price forecasts, adding to the uncertainty. The necessary infrastructure would also have a useful life of 20 to 60 years, extending well into the energy transition. As such, producers will likely consider not only prices, but also long-term demand and volumes more than they have historically.

To reduce these risks, producers and pipeline operators typically secure long-term customers before construction begins, providing greater revenue and volume certainty for both pipeline and upstream investments. WCOP remains too

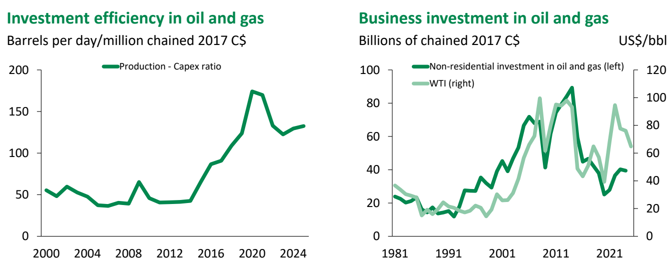
[9] Break-even prices represent the profitability threshold for oil producers. They include operating expenses, diluent and adjustments for transportation and crude quality to make the measure comparable with WTI.

early in its development to have secured such commitments. China, South Korea, Japan and India have expressed interest in additional Canadian crude, but whether this translates into binding long-term shipping or purchase agreements remains uncertain.

Unlocking Upstream Investment Requires More than Egress

Oil and gas capital investment remains well below 2014 boom levels despite stronger production and cash flow. Since 2014, the sector has become much more focused on efficiency and capital discipline. Companies are producing a lot more with less new investment. In fact, the sector can now produce about three times the output with the same amount of capital invested (graph 8).

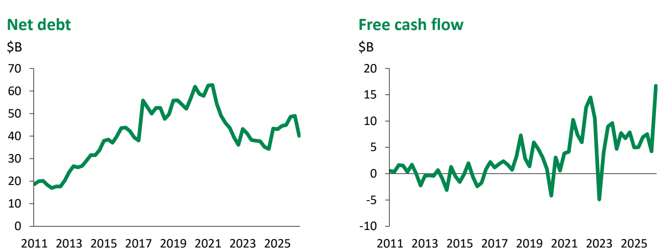
Graph 8
Production Growth Continues Despite Subdued Capital Spending



Statistics Canada, Canada Energy Regulator and Desjardins Economic Studies

The new WCOP could unlock a meaningful round of private upstream investment by improving market access and reducing egress risk for Alberta producers. The industry is in a much better position to fund that investment than it was in the last cycle: balance sheets are healthier, net debt is lower and free cash flow generation remains strong (graph 9).

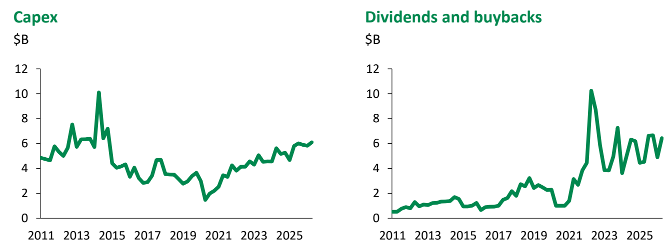
Graph 9
Canadian Upstream Producers Are Delevered and Cash-Rich



Note: Aggregate financial data include Canadian Natural Resources, Suncor Energy, Imperial Oil, Cenovus Energy, Whitecap Resources, Tamarack Valley Energy and Athabasca Oil.
Bloomberg and Desjardins Economic Studies

New pipeline capacity alone may not be enough to trigger a large investment wave. In recent years, producers have prioritized debt reduction, dividends and buybacks over aggressive production growth (graph 10), and many have formal capital allocation frameworks that return excess cash to shareholders once leverage targets are met. That means to shift priority away from balance-sheet strength and capital returns and back into upstream growth, producers will need a clear line of sight on durable egress, competitive project economics, regulatory certainty and potentially policy or fiscal incentives.

Graph 10
Capital Allocation Has Shifted Toward Shareholder Returns



Note: Aggregate financial data include Canadian Natural Resources, Suncor Energy, Imperial Oil, Cenovus Energy, Whitecap Resources, Tamarack Valley Energy and Athabasca Oil.
Bloomberg and Desjardins Economic Studies

The trilateral Pathways Memorandum of Understanding (MOU) links WCOP to oil sands decarbonization. Pathways is intended to solve the carbon constraint by investing in carbon capture, utilization and storage (CCUS). A more predictable industrial carbon price framework would improve the financial return on carbon capture investment. The new Canada–Alberta approach sets a lower headline carbon price than the previous federal path, while making carbon credits more valuable and predictable through minimum transfer prices and carbon contracts for difference.

Whether producers invest enough to fill WCOP will therefore depend partly on whether Pathways can lower the carbon cost of new barrels and provide compliance certainty. If it does, it could strengthen the case for upstream growth. There is still significant uncertainty as to how effective CCUS will prove to be, both initially and over time. CCUS performance so far has been mixed, with several projects capturing meaningfully less CO_2 than designed. Underperformance would leave a residual carbon liability on incremental barrels and could weaken the economics of marginal upstream investment.

Meaningful Near-Term Benefits, Overstated Long-Term Impact

The Government of Alberta estimates that the WCOP project and associated upstream construction could generate a sizable economic benefit. Its estimates are based on total construction capital spending, including upstream activity, of roughly $61B to $70B in today's dollars over the 2026 to 2038 period. Of this amount, Alberta estimates the pipeline itself would cost $35.2B to $43.7B, implying roughly $26B in upstream investment to ramp up supply.

This upstream investment assumption appears reasonable, albeit on the low side. Expanding production could cost as little as $25,000 per daily barrel when existing facilities are optimized, or as much as $80,000 when new oil sands infrastructure is required. This puts the total investment needed between roughly $24B and $76B, depending on the production mix that will be used.

However, Alberta's estimated economic benefit may be somewhat optimistic. Alberta estimates that the construction of the pipeline could boost Canadian GDP by more than 0.4% at its peak in the early 2030s, while employment could rise by 0.8% nationwide at the height of construction (table 2). The effects would be larger in Alberta and British Columbia, where construction could support up to 45,000 and 70,000 jobs, respectively. Using Alberta's construction capital spending assumptions, we estimate the growth impact could approach 0.3% during peak construction years but fade thereafter.

Table 2
Alberta's Estimates of WCOP's Economic Impact

% UNLESS OTHERWISE INDICATED	Canada	Alberta	BC
Construction phase (2026–2038)			
GDP (direct and indirect effects)	0.4	—	1.5
Jobs (thousands)	140	45	70
Operational phase (2030s–2040s)			
GDP (direct and indirect effects)	0.6	3.5	—
Jobs (thousands)	50	—	—

Government of Alberta and Desjardins Economic Studies

The operating-phase estimate also requires caution. Alberta's study suggests that, starting in the 2030s, upstream production growth associated with the project could raise real Canadian GDP by an average of more than 0.6% per year by the 2040s, including direct and indirect effects. This is unlikely to be the right growth profile if production ramps up to fill the pipeline within one to two years. In that case, the impact would mainly appear as a one-time boost to output growth during the ramp-up period, rather than as a sustained annual lift. We estimate that one-time real Canadian GDP growth effect at roughly 0.4 to 0.5 percentage points, and that the level of output will be permanently higher thereafter.

Meaningful Fiscal Revenue but an Uneven Risk-Sharing Structure

The fiscal story is a tale of two phases. During construction, the big winners would likely be Ottawa and British Columbia. On a cumulative basis over the build period, we estimate that the federal government could collect $3B to $4B from personal income taxes (PIT) on construction labour income and corporate income taxes (CIT) on supplier and contractor profits,[10] while BC could collect another $1B to $2B. Alberta's revenue take during the construction phase would likely be less than $1B. The operating phase is when Alberta would get paid, primarily through recurring bitumen royalties. At 950,000 b/d of incremental production and WTI around US$60/bbl, royalties alone could rise by roughly $2B to $4B per year before accounting for provincial CIT and PIT. The federal government would also see a meaningful annual lift from higher upstream profitability and labour income, likely in the range of $1B to $2B per year. BC would still benefit from pipeline and terminal operations, but that would be a much smaller annuity.

Government royalty and tax receipts would improve project viability, but the current structure could leave Alberta materially better off while the federal government carries a disproportionate share of the downside risk. Alberta would capture the largest recurring fiscal upside through bitumen royalties, while Ottawa could be left absorbing project-level losses, financing risk and political risk if the economics disappoint.

Cost overruns are an important consideration in any major infrastructure project. A project structure that aligns risks and returns among governments, producers, shippers, Indigenous partners and external investors may help support long-term success. Government involvement, including through credit enhancements or guarantees, could play a role in facilitating investment while helping to balance public and private interests and manage overall exposure.

[10] Estimates are intended as order-of-magnitude fiscal impacts. They use Alberta's construction cost estimate, allocate spending 70% to Alberta and 30% to British Columbia, and assume labour income accounts for about 40% to 45% of total spending. Personal income tax impacts are based on representative middle-income tax rates, while corporate income tax impacts use general statutory rates of 15% federally, 8% in Alberta and 12% in British Columbia.

Conclusion

WCOP has a strong strategic case, but there is little room for cost overruns, and the fiscal benefits would be unevenly distributed. Alberta stands to capture the largest recurring upside through bitumen royalties, while Ottawa would bear a disproportionate share of the construction-phase and downside risk. Yet the proposal remains highly preliminary, and much more certainty will be needed before investment can flow. Investors will be looking for confidence in long-term demand; oil prices strong enough to support new production; clearer answers on design and delivery timelines; more certainty on CCUS performance; and a financing and risk-sharing structure that better aligns exposure across governments, producers and investors. Without greater certainty, WCOP may remain strategically compelling but commercially difficult to advance given the scale of investment required.