September 2026

Institute for Energy Economics and Financial Analysis

Assessing Alberta's proposed West Coast Oil Pipeline

Uncertain utilization and unfavourable economics

Mark Kalegha, Energy Finance Analyst, IEEFA
Will Scargill, Independent Consultant

Contents

Tables

Key findings

IEEFA's analysis of future supply scenarios and global market conditions challenges the notion that the West Coast Oil Pipeline can be justified based on capacity need.

Brownfield pipeline expansion projects can accommodate forecasted production growth at lower costs with higher degrees of execution certainty.

The West Coast Oil Pipeline's tolls are likely to be significantly higher than existing pipelines, and the project would likely represent a net loss to the industry.

Even if oil exported to the Pacific can achieve a premium, this is unlikely to translate to WCS prices, and high tolls would mean lower netbacks for producers.

Executive summary

In this report, IEEFA assesses whether the Government of Alberta's proposed West Coast Oil Pipeline would be necessary to support crude oil growth under the range of projections detailed in the Canada Energy Regulator's (CER) Canada's Energy Future 2026 report. We conclude that the proposed pipeline, which would transport 1 million barrels of oil per day between Alberta and the west coast of British Columbia, is unlikely to be needed to meet capacity needs in the future.

Our analysis also indicates that the likely cost to the industry in terms of commitments and tolls on exports would outweigh the potential economic benefits, and the project as a whole is risky in the context of the energy transition. In particular, our report finds:

- Under the four scenarios modelled by the CER, only the Higher Scenario would indicate a need for more capacity beyond that which can be added by clearly delineated brownfield expansions.
- The ongoing energy transition has significantly slowed oil demand growth and looks set to bring about a plateau or decline in the coming years. In this context, long-term USD95 per barrel world oil prices driving supply growth in the CER's Higher Scenario appears increasingly unlikely, particularly with demand for electric vehicles and other clean technologies rising in response to recent oil supply shocks.
- IEEFA's analysis concludes that the West Coast Oil Pipeline is unlikely to be needed to meet future export capacity requirements.
- Existing pipelines and proposed, lower-cost expansion projects provide sufficient pipeline capacity under all likely CER scenarios.

After examining the need for additional West Coast Oil Pipeline egress capacity in light of existing and planned pipeline projects and expansions, we analyze potential economic impacts of the project on the industry.

- The high costs associated with the project mean it is unlikely to generate a net economic benefit for Canada's oil and gas sector. Tolls are likely to be significantly higher than those of existing pipelines, with our modelling yielding initial tolls of CAD18.7-23.7 per barrel assuming a similar tolling framework to the Transmountain Expansion Project (TMX).
- Even if prices on exports to Asia at Canada's Pacific coast are higher than those in the U.S., routing new pipeline capacity to the Pacific over the U.S. is unlikely to impact the Western Canada Select-West Texas Intermediate (WCS-WTI) differential due to the high transportation cost and availability of other routes.
- Any potential premium on oil prices at the Pacific coast compared to the U.S. is unlikely to compensate for the high tolls that would need to be charged on the West Coast Oil Pipeline. Our analysis sees long-term committed shippers on the proposed pipeline achieving USD5-8 (2025 prices) less value per barrel exported in most scenarios compared to without the

pipeline, depending on the final pipeline cost estimate. This could represent an annual drag on industry with a value of CAD2.2-3.2 billion (2025 dollars) over a 20-year contract period.

In addition, the pipeline project faces significant execution risks. As with other recent pipeline proposals in Western Canada, the project would have to overcome considerable challenges, including the potential for material delays and cost overruns. The project also poses substantial risks to the public sector—based on current proposals, governments could ultimately own approximately 90% of the pipeline and, while long-term shipping contracts may provide revenue certainty, previous contractual arrangements suggest these public sector pipeline owners would bear much of the execution risk.

In sum, our analysis suggests that the large commitments required to support the West Coast Oil pipeline may harm rather than secure future returns for investors. The global energy sector is undergoing significant changes that challenge the economic outlook of the pipeline project—wider market conditions that would be required to support rapid output growth are far from certain and the global energy transition may make this even less likely. Potential benefits of the pipeline are steeped in risk, and other investment priorities may offer more economic resilience as the energy transition moves forward.

Introduction

In this report, we analyze the case for the proposed West Coast Oil Pipeline—a project that would transport 1 million barrels per day (bpd), running roughly 1,200 kilometers (km) between Bruderheim, Alberta and the west coast of British Columbia.[1] First, we assess whether the project's export capacity additions would be necessary to support crude oil output growth under the range of projections detailed in the Canada Energy Regulator's (CER) Canada's Energy Future 2026 report. Second, we evaluate the likely cost to the industry in terms of the commitments and tolls to be paid on exports, and how these costs weigh against potential economic benefits. Finally, we examine the impact that the ongoing energy transition may have on the cost-benefit analysis of this project.

Our research focuses on the questions of egress capacity and value maximization. Environmental concerns, the rights of indigenous communities, and provincial-federal relations are not analyzed within the scope of this report, but should be kept in mind, as they will have significant implications for decisions around any new pipeline.

This report finds that the West Coast Oil Pipeline would likely not be needed to secure export routes in the coming decades. Although the CER's analysis sees supply growth requiring some new export capacity in most scenarios, additional brownfield expansions are available to come online this decade to avoid widening of the Western Canada Select-West Texas Intermediate (WCS-WTI) differential and negative effects on gross industry revenue. After taking into account these projected

[1] Government of Alberta. West Coast Oil Pipeline Project. 2 July, 2026.

expansions, there would only be a need for any further new capacity if oil output followed the trajectory of the CER's Higher Scenario. Making large scale investment on the basis of an ambitious growth scenario comes with significant risk. This may be more justifiable where there is a growing market to be captured, but this proposal comes in the context of a global oil market facing major structural changes, with demand growth appearing to be nearing its end.

The potential for acceleration of the energy transition is likely to limit future long-term oil prices and brings the prospect of structural decline.

With our analysis suggesting a poor chance that the West Coast Oil Pipeline repays its CAD35.2-43.7 billion cost, the key question for policymakers and industry is whether the export route diversification is worth that cost. The energy transition and its potential for acceleration may significantly weaken the value that investments diversifying oil export routes could have for the economy. The "Global Net-Zero" scenario that the CER considered in its 2023 version of Canada's Energy Future saw Canadian oil output halving by 2040 and dropping by almost 80% by 2050, driven by lower oil prices as the world phases out fossil fuels. While the world is not currently on track to meet climate targets, this is a stark illustration of the potential impacts of such acceleration.

While exports of Canadian crude to Asia may yield a delivered premium at times, this value does not appear sufficient to warrant the cost of the proposed pipeline. Our analysis of the dynamics through which the WCS-WTI differential is formed suggests that the differential is unlikely to be materially impacted by the pipeline. This means that any premium would only likely be captured by those companies committing to shipping through the pipeline, and its value appears far short of that required to offset the tolls. In all but the Higher Scenario, the shippers through the pipeline would achieve a netback value that is USD5-8 lower per barrel (2025 prices) than without the pipeline.

Much of the risk of the pipeline's value not offsetting its cost should, short of government subsidy, fall on industry and its investors—but it should also concern policymakers. Lower profits for the sector translate into lower provincial and federal taxes.

Perhaps more importantly, public sector involvement in the project comes with major risks and opportunity costs. At present, it appears that the public sector would end up owning 90% of the West Coast Oil Pipeline, and while long-term contracts may secure revenues, previous contractual arrangements suggest they would face much of the execution risk. Recent polling suggests most Albertans believe that the economy is too dependent on oil and gas and oppose the use of public money to finance oil pipeline infrastructure[2]. In the case of the Trans Mountain Expansion Project (TMX), less than half of the CAD20 billion overspend was recoverable through tolls, with the remaining burden falling on the taxpayer-owned Trans Mountain Corporation.

The West Coast Oil Pipeline proposal primarily appears to offer optionality and diversification against localized U.S. oil market risks in return for the major investment required. It is important for the

[2] Pembina Institute. Polling Albertans on Energy and Climate 2026. 2026.

proposal's cost-benefit balance to be considered alongside those of other investments that could provide sectoral diversification and economic resilience to wider transition-related risks.

Background

The Western Canadian Sedimentary Basin, which covers most of Alberta and parts of British Columbia, Saskatchewan, Manitoba, and the Northwest Territories, has witnessed steady growth in oil output over the past two decades. The basin contains the majority of Canada's oil reserves and accounts for most of the country's production. Canada's oil production has more than doubled to 5.3 million bpd since 2000, almost entirely due to the growth in production from Alberta's oil sands.[3] In 2025, Alberta produced 84% of the country's total output,[4] with most of this coming from bitumen either mined or extracted "in-situ" from oil sands projects. Oil and gas contributed around a quarter of Alberta's total economic output in 2024,[5] and crude oil comprised almost 20% of Canada's total exports.[6] Due to this significance, concerns and discourse are prevalent regarding production evacuation strategies, export pipeline availability, routes to market, and the need to align egress capacity with production levels to capture the full value of exports.

Production and transport of oil sands bitumen present cost challenges. A heavy and highly viscous form of petroleum, bitumen must either be upgraded into "synthetic crude" or blended with diluent (typically light oil, such as condensate) in order to be exported through pipelines. Diluted bitumen (dilbit) remains a very heavy oil that requires a high level of processing, typically at highly complex refineries, to refine it into oil products. Dilbit therefore sells at a significant discount to the typical North American crude oil price benchmark, the West Texas Intermediate (WTI), and the global benchmark, Brent. The price dilbit can achieve in Alberta is also significantly affected by the cost of transporting oil to market. While the main dilbit benchmark, the Western Canada Select (WCS), is priced at around a USD5-8 per barrel discount to WTI in Houston[7] close to complex Gulf Coast refineries, the discount at its typical pricing point in Hardisty, Alberta averaged USD12 per barrel in 2025.[8]

While most projections foresee a case for increasing egress capacity, the expected scale of that expansion varies across outlooks. A range of pipeline development and expansion projects has routinely been proposed by private industry operators and public entities. The fate of such projects in recent years has been mixed. Some, such as the Keystone Pipeline, have been completed relatively in line with proposals. Others have faced significant economic, environmental, and regulatory challenges. The Northern Gateway, Energy East, and Keystone XL pipelines were proposed but cancelled in the 2010s. The TMX boosted Western Canada's existing egress capacity

[3] Canada Energy Regulator. Market Snapshot: Canada Sets New Record in Crude Oil Production in 2025. June 2026.
[4] *Ibid*.
[5] Canadian Association of Petroleum Producers. Alberta Builds on Oil and Natural Gas. Accessed July 2026.
[6] Observatory of Economic Complexity. Canada. Accessed July 2026.
[7] Johnston, Rory. Why Are Western Canadian Oil Prices So Strong? Macdonald-Laurier Institute. April 2025.
[8] Government of Alberta. WCS Oil Price Dashboard. Accessed July 2026.

but experienced substantial cost overruns and toll disputes. TMX was not completed until 2024, over a decade after its initial proposal.

Recent trade tensions between Canada and the United States introduced a new dimension into planning additional export capacity. Concerns around the Canadian economy's reliance on the United States have taken on an increased significance, including for the oil sector. TMX reduced Canada's reliance on the U.S. market, but 89% of crude oil exports still went to the United States in 2025, down from 97% in 2023.[9]

In this context, the government of Alberta announced a proposal for a pipeline to transport one million bpd of crude oil from Alberta to the Pacific coast. Initially floated in October 2025, the project progressed in November with the signing of a Memorandum of Understanding (MOU) between the Alberta and federal governments. The MOU sets an objective of growing oil and gas production while reducing carbon intensity through the Pathways carbon capture project.[10,11] The proposal submitted by the Alberta government to the Major Projects Office on July 2, 2026, argues that the West Coast Oil Pipeline can unlock production growth, boost the price achieved for Alberta's oil through increased access to international markets, and have positive impacts on GDP more widely.[12]

The scale of the proposed pipeline, together with its capital requirements and potential for taxpayer exposure, make the project a compelling candidate for IEEFA evaluation of the role it may or may not play in achieving Canada's economic goals.

[9] Statistics Canada. Canadian crude oil reaches new heights in 2025. June 2026.
[10] Prime Minister of Canada. Canada-Alberta Memorandum of Understanding. November 2025.
[11] IEEFA has questioned the effectiveness of the Pathways project, as well as the project's costs. IEEFA. Financial Risks of Carbon Capture and Storage in Canada: Concerns About the Pathways Project and Public Energy Policy. December 2024.
[12] Government of Alberta. West coast oil pipeline project. July 2026.

The proposed West Coast Oil Pipeline should be viewed in the context of existing and other proposed export pipelines in Western Canada

Western Canada's existing crude oil export system consists mainly of the Enbridge Mainline, Trans Mountain Pipeline, Keystone Pipeline, Express Pipeline, and several smaller export lines serving regional markets. Together, these systems form the backbone of Alberta's crude oil transportation network and provide access to domestic, U.S., and global refining markets.

Table 1: Western Canada's existing crude oil export pipelines

PIPELINE	OPERATOR	CAPACITY ('000 BPD)	YEAR OF COMMISSIONING	PRIMARY MARKET DESTINATION
Mainline System	Enbridge	**3,227**	1950s	U.S.
Trans Mountain	TMPL	**887**	1953	Global/Asia
Keystone	TC Energy	**622**	2010	U.S.
Express	TC Energy	**310**	1997	U.S.
Milk River	Plains All American	**98**	1950s	U.S.
Rangeland System	Plains All American	**45**	1980s	U.S.

Sources: Compiled using data from company disclosures (including Enbridge, Trans Mountain, TC Energy) and the Canada Energy Regulator; IEEFA.

The largest component of Western Canada's export network is Enbridge's Mainline System, which transports crude oil from Alberta and Saskatchewan to refining markets in the U.S. Midwest, Eastern Canada, and U.S. Gulf Coast. The Mainline System accounts for the majority of Canada's export pipeline capacity.

The TMX system, put in service on May 1, 2024, increased the existing Trans Mountain system's capacity from roughly 300,000 bpd to 890,000. The expansion is the largest addition to Western Canada's crude oil export capacity in more than a decade and provides increased access to tidewater marine export markets. TMX was initiated by Kinder Morgan Canada before being purchased and completed by the Canadian government. Its construction was characterized by substantial cost overruns, delays, legal challenges, and consumption of large public subsidies.[13] The project highlights the hurdles facing large-scale greenfield pipeline development in Canada.

Additional export capacity is provided by the Keystone Pipeline, which connects Alberta production to refining markets in the U.S. Midwest and Gulf Coast, while the Express system serves refining markets in the Rocky Mountain region. Smaller export infrastructure such as the Milk River Pipeline and the Rangeland pipeline system provide cross-border access. Milk River connects Alberta to

[13] IEEFA. Canada should learn from the Trans Mountain Expansion Pipeline's fiscal issues. September 2025.

Montana and the Rangeland connects into the Rocky Mountain region. Although relatively modest compared to larger export systems, the Milk River and Rangeland pipelines offer incremental egress capacity.

Proposed Pipeline Expansion Projects

Various operators in Canada are in different stages of pipeline capacity expansion and development projects. The overriding objective of these initiatives is to boost egress capacity to accommodate potentially higher production output.

This report classifies proposed expansion projects into three broad categories:

A. Tier 1 projects: Representing fairly certain egress capacity from projects that have a positive final investment decision (FID) and are already under or about to commence construction.
B. Tier 2 projects: Near-term expansion opportunities with pending FID mandates for which materially progressive actions have been taken, including community engagement and submission of applications, with regulatory approval received or pending.
C. Tier 3 projects: Earlier-stage or preliminary conceptual projects. While some may be pending FID, details are limited, with minimal documentation submitted to regulatory authorities.

Tier 1 Expansion Projects

Enbridge Mainline Optimization Phase 1 (MLO 1)

Enbridge is advancing the first phase of its mainline optimization program, which is designed to increase broader system capacity by 150,000 bpd of crude oil.[14] Phase 1 is the first stage in a larger expansion initiative expected to unlock up to 400,000 bpd of incremental egress capacity. MLO 1 focuses on optimizing and upgrading existing infrastructure on Enbridge-owned property and includes the use of drag-reducing agents, modifications to piping configurations, and improvements to storage facilities and terminal operations. The project's budget is approximately USD1.4 billion. Construction is expected to start in 2026 with full completion expected by 2028.

Express-Platte Pipeline System Expansion

Enbridge is undertaking a 30,000-bpd capacity expansion on its Express pipeline system which aims to boost capacity from 310,000 bpd to 340,000 bpd.[15] This project, which is part of a larger Southern Illinois Connector project, has a budget of CAD50 million and is expected to be completed in 2026.[16]

[14] Enbridge. Mainline Optimization. June 2026.
[15] Enbridge. With MLO1 and MLO2 in the batting order, Enbridge has close to 500,000 bpd of new capacity planned by decade's end to support Western Canadian production growth. November 19, 2025.
[16] Government of Alberta. Express-Platte Pipeline System Expansion. June 2026.

Trans Mountain Drag Reducing Agent (DRA) Project

Trans Mountain Corporation, operator of the Trans Mountain pipeline system (TMPL), has filed an application to install drag-reducing agents on 12 existing pump stations along the TMPL. The project is classified as a brownfield expansion and will be executed within existing facilities, which the operator asserts will have minimal environmental impact, and will boost throughput capacity by 90,000 bpd.[17] The project was approved in June 2026 by the CER, and work is expected to commence promptly, with a target in service date of January 2027.[18] The project budget is reported at approximately CAD9 million.[19]

Tier 2 Expansion Projects

Enbridge Mainline Optimization Phase 2 (MLO 2)

Enbridge has identified opportunities to add another 250,000 bpd of transportation capacity on its flagship mainline system.[20] The MLO 2 project involves optimizing existing pipelines using drag reducing agents and pumps, as well as enhancement and upgrades at the Enbridge-owned Cromer Terminal. The project has begun public engagement with land and indigenous stakeholders. Enbridge initially announced that a final decision would be made by mid-2026 with an anticipatory in-service date of late 2028. However, the project was postponed in July 2026 due to producers' lack of commitment to increasing output.[21]

Trans Mountain Mainline Optimization Project

Trans Mountain is proposing another project to optimize performance on its existing network that would unlock an additional 210,000 bpd of throughput capacity. The project would involve laying 30 km of new pipeline, installing new pump stations, and upgrading power transmission and distribution infrastructure.[22] The project is still in its early planning stages and public consultations are ongoing. The project is subject to CER approval and Trans Mountain anticipates submitting an application to the regulator by August 2026. Construction is to take place over four or more years. For the purpose of this report, we assign a potential in-service date of 2030.

[17] Trans Mountain. Drag Reducing Agent. June 2026.
[18] Canada Energy Regulator. Trans Mountain Pipeline ULC - Drag Reducing Agent Project. May 12, 2026.
[19] Government of Alberta. Transmountain Pipeline Drag Reducing Agent (DRA) Project. February 2026.
[20] Enbridge. Mainline Optimization. June 2026.
[21] Global News. Canada's Enbridge postpones plans for second phase of Mainline oil pipeline expansion. July 31, 2026.
[22] Trans Mountain. Mainline Optimization Project. June 2026.

Tier 3 Expansion Projects

Prairie Connector

This project is a partial revival of elements of the cancelled Keystone XL pipeline project and similarly aims to transport crude from Alberta to the Canada-U.S. border. The pipeline will key into the proposed Bridger pipeline, which would then move the crude from the border to Guernsey, Wyoming. We consider the project a hybrid of green and brownfield development, as it plans to leverage pre-existing rights of way and 150 km of previously installed pipeline. This strategy is intended to help reduce hurdles facing pure greenfield developments. The Prairie Connector is sponsored by South Bow, a company that was spun out of TC Energy's liquid pipeline business, and is expected to increase southbound egress capacity by 450,000-550,000 bpd initially, with potential for an additional 550,000 bpd in future phases.[23] South Bow is currently undergoing engagement with communities and recently announced it had secured long-term shipping commitments for the project.[24] It is targeting mid 2027 for FID and late 2028 for a potential in-service date if the project commences.

Mainline Optimization Phase 3&4 (MLO 3&4)

Additional phases of Enbridge's Mainline Optimization program are being explored. While details are scarce, these projects aim to build upon previous capacity additions and increase utilization of existing infrastructure, rather than constructing new greenfield corridors. Some analysts suggest that MLO 3&4 could deliver egress capacity increments of 300,000 bpd.[25]

Dakota Access North project

Another speculative source of future egress capacity involves expanded connectivity between Western Canadian supply and the U.S. pipeline network through the Dakota Access Pipeline (DAPL) system. Discussion between Enbridge and Energy Transfer are in early stages and details on the project are not yet available in the public domain, but some analysts suggest connecting spare capacity on DAPL to the Enbridge mainline may add up to 250,000 bpd additional egress capacity to the system.[26]

[23] Bridger Pipeline Expansion LLC. Bridger Pipeline Expansion Application for a Certificate of Compliance. March 26, 2026.
[24] South Bow. South Bow announces successful open season. May 29, 2026.
[25] Quantum Intelligence. Enbridge eyes 2 more Mainline oil system optimization projects. November 7, 2025. See Also: Enbridge. Fourth Quarter Update. February 13, 2026, p.6–7.
[26] Plainview Energy Analytics. Energy Transfer & Enbridge Team Up on 250k bpd Dakota Access North. November 6, 2025.

West Coast Oil Pipeline project

The focus of this report is on the West Coast Oil Pipeline project, spearheaded by the province of Alberta to construct new export capacity for moving 1 million bpd of additional crude to tidewater on the west coast of British Columbia. The province foresees the pipeline being developed and operated by a joint venture between the Alberta Petroleum Marketing Commission, Trans Mountain Corporation, and Pembina Pipeline Corporation. The project is estimated to cost between CAD35.2 and CAD43.7 billion, with construction to begin between 2027 and 2029.[27] The project aims to align with some elements of TMX infrastructure, pathways, and disturbed lands, and as such is regarded by proponents as a hybrid rather than a new greenfield project.

The project is in early stages of development. Depending on when FID is taken, and the successful execution of an ambitious concurrent development plan, the pipeline could be in service between 2032-2034. The scale of the development— and prior precedent with large-scale infrastructure development in western Canada—means the project faces elevated execution risk and would have to overcome significant hurdles, including the potential for material delays and cost overruns.

[27] Government of Alberta. West Coast Oil Pipeline Project. July 2, 2026.

Table 2: Proposed export pipeline expansion projects in Western Canada

PROJECT	PROPONENT	PROPOSED CAPACITY ('000 BPD)	STATUS	PROPOSED BUDGET (CAD$, MILLIONS)	EXPECTED IN SERVICE	PRIMARY DEST.
Mainline Optimization Phase 1 (MLO 1)	Enbridge	150	Pre-construction	$1,400	2028	U.S.
Express-Platte System Expansion	Enbridge	30	Pre-construction	$50	2028	U.S.
TIER 1 (Fairly certain egress capacity)		**180**				
Mainline Optimization Phase 2 (MLO 2)	Enbridge	250	Pre-FID	N.A.	TBD	U.S.
Trans Mountain DRA	Trans Mountain	90	Pre-construction	$9	2027	Global/ Asia
Trans Mountain Mainline Optimization	Trans Mountain	210	Early stage development	$3,000+	2028	Global/ Asia
TIER 2 (Near-term with material actions)		**550**				
Prairie Connector	South Bow	550 +	Pre-FID	N.A.	Late 2028	U.S.
Mainline Optimization Phase 3, 4 (MLO 3, 4)	Enbridge	TBD	Feasibility/ planning	N.A.	TBD	U.S.
Enbridge and Energy Transfer Dakota Access North	Enbridge/ Energy Transfer	TBD	Feasibility/ planning	N.A.	TBD	U.S.
West Coast Oil	Joint venture	1,000	Pre-feasibility	$35,200-$43,700	TBD	Global/ Asia
TIER 3 (Earlier stage or conceptual)		**1,550 +**				
TOTAL PROPOSED CAPACITY EXPANSION		**2,280 +**				

Sources: Compiled using data from company disclosures (including Enbridge, Trans Mountain and South Bow) and the Government of Alberta; IEEFA.

IEEFA's analysis of alternative supply scenarios and global market conditions challenges the notion that the West Coast Oil Pipeline can be justified based on capacity need

CER's outlook offers a range of scenarios for future crude oil supply across Canada

By making assumptions about future economic growth, technology adoption, climate policy, and energy demand, the CER lays out four distinct scenarios to explore how Canada's energy system and crude oil supply could evolve through 2050.[28] CER views these scenarios as plausible future pathways, and they can be useful in assessing future infrastructure needs and risks. The CER scenarios assume no physical export capacity constraints exist that affect supply, and the WCS-WTI differential is assumed to stay constant at USD12.5 per barrel (in 2025 prices).

Current measures scenario

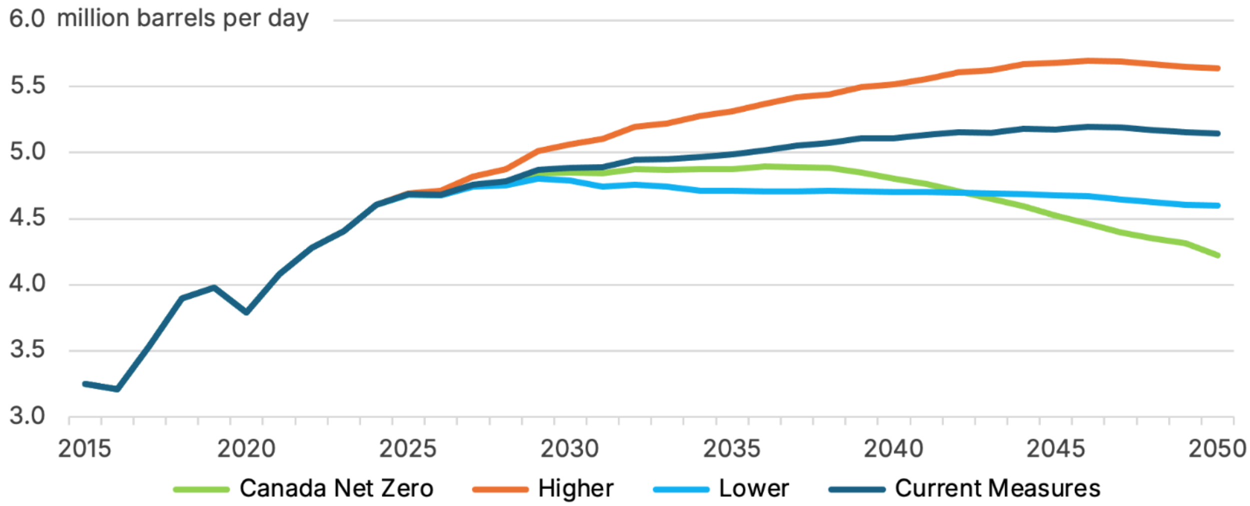
The Current Measures scenario represents a continuation of existing policies, moderate economic growth, and mid-range global commodity prices. It is CER's base case and assumes Canadian crude oil production continues to grow through the 2030s before moderating and stabilizing over the longer term. Under Current Measures, production increases from roughly 5.6 million bpd in 2025 to 6.1 million bpd by 2040, before stabilizing near 5.9 million bpd by 2050. Brent prices peak at USD75 per barrel in the 2030s and remain at those levels throughout the reference period.

Higher scenario

The Higher Scenario explores a future characterized by stronger economic growth and higher prices in global energy markets. Elevated energy prices improve the economics of oil sands and conventional production, leading to increased investment and greater production growth. Brent prices rise to approximately USD95 per barrel (in 2025 prices) by 2030 and remain at those levels through 2050. Crude production rises from 5.5 million bpd in 2025 to approximately 6.1 million bpd by 2030, before peaking near 6.7 million bpd in the mid 2040s and remaining elevated thereafter. Out of all scenarios, crude export volumes out of Alberta are the highest in the Higher Scenario. Thus, it provides an indication of the upper range of pipeline capacity requirement that could materialize in the future.

[28] Canada Energy Regulator. Canada's Energy Future 2026. March 17, 2026.

Canada Energy Regulator crude oil production scenarios to 2050



Source: Canada Energy Regulator; IEEFA.

Lower scenario

The Lower Scenario examines an opposite set of assumptions—lower global oil prices, slower growth, and weaker global oil market demand. Lower commodity prices reduce the incentives for investment in higher-cost Canadian production, particularly oil sands projects, resulting in more limited supply growth. Brent prices plateau at USD55 per barrel in the 2030s. Crude oil production reaches 5.7 million bpd by 2030 and then gradually falls to 5.1 million bpd by 2050. For pipeline capacity analysis, the Lower Scenario provides a useful test of the downside case and potential underutilization of egress capacity.

Canada net-zero scenario

The Canada Net-Zero Scenario is based on a pre-determined outcome: Canada realizes net-zero greenhouse gas emission by 2050. This scenario assumes that climate action would accelerate domestically and globally, resulting in lower demand for oil and natural gas, lower long-term energy commodity prices, and faster deployment and adoption of low-carbon technologies. Brent prices hover within a tight range around mid-USD60 per barrel for most of the reference period. Crude output continues for near-term growth but peaks at 5.8 million bpd in the mid-2030s before declining to 4.7 million bpd by 2050. Just as in the Lower Scenario, Canada Net-Zero exemplifies a future where restricted production could end up making excess egress capacity redundant.

Global market conditions indicate that several factors may lead to a faster energy transition and lower long-term oil demand

As discussed earlier, the large distances Alberta's oil products must be transported to reach markets mean that prices are significantly affected by the availability and cost of transport. The demand and prices paid for that crude, however, still depend primarily on global oil markets. Due to high initial capital investment requirements, analysts typically place undeveloped oil sands resources near the top of the global cost curve.[29] Although once-developed output can remain stable for decades and operating costs have reduced in recent years, this means that the viability of new oil sands developments can often be among the most at risk from lower oil prices. Global market dynamics will therefore be a key determinant of the speed at which the province's oil output can grow. The impact of the energy transition on the global oil market means that the conditions for the CER's Higher Scenario appear increasingly unlikely.

Structural shifts in the oil market are expected to lead to zero oil demand growth, followed by decline

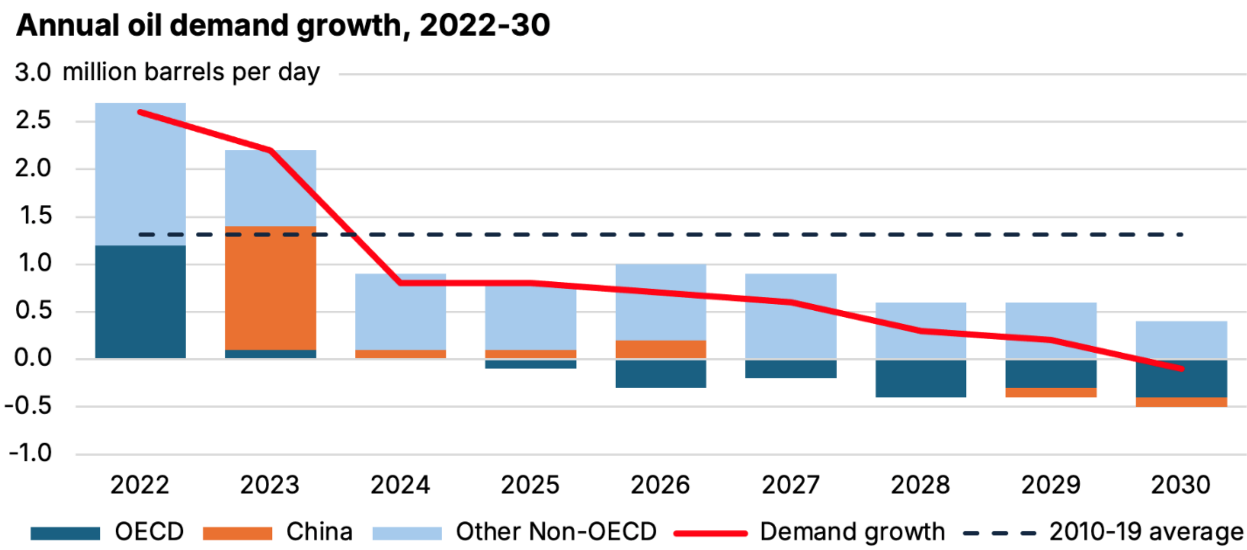
Major structural shifts are underway in global energy markets. Since rebounding from the impact of COVID-19, oil demand growth has slowed to significantly below pre-COVID averages, with much of the downward impact coming from the electrification of road transport, a market that accounts for around 45% of global oil demand. Electric vehicles represented 25% of global new car sales and 5% of cars on the road in 2025. This is up from just 3% of new car sales and 1% of the fleet in 2019,[30] and is already estimated to have displaced 1.7 million bpd of global oil demand (almost 2%).[31]

China, which was the engine driving global oil demand growth for the past 20 years, is electrifying significantly faster than the rest of the world. Electric vehicles represented 53% of new car sales in China in 2025. In the International Energy Agency's (IEA) Stated Policies Scenario, which it describes as aiming to "reflect the prevailing direction of travel for the energy system," this increases to 94% by 2035, at which time 59% of cars on China's roads are projected to be electric. While trucks are electrifying more slowly than cars, China is leading here too, with 26% of new truck sales electric in 2025 and policies aiming for 40% of sales to be electric by 2030. These dynamics, combined with the peaking of China's population at the start of this decade, mean a major shift for global oil markets. Chinese transport fuel demand appears to have already peaked,[32] and its overall oil demand is expected to peak by 2027.[33]

---

[29] Rystad Energy. Shale project economics still reign supreme as cost of new oil production rises further. October 1, 2024.
[30] IEA. Global EV Data Explorer. Accessed July 2026.
[31] IEA. Global EV Outlook 2026. May 20, 2026.
[32] IEA. Oil 2025. 2025.
[33] Reuters. China oil demand to peak in 2027, up 100,000 bpd this year, state researcher says. September 8, 2025.

While other emerging markets' oil demand is expected to keep growing, at least in the medium-term, they do not appear likely to offset the loss of Chinese demand growth, and the IEA expects oil demand growth to drop to zero in 2030, and then enter decline. In its Stated Policies Scenario, this would mean global oil demand plateauing through 2050. Energy transition-related technological changes and climate action, however, could push oil demand into long-term decline faster than expected.



Source: IEA Oil 2025; IEEFA.

The speed of technology transitions, cost, and policy may all lead to a faster transition and lower long-term oil demand. Analysts have repeatedly underestimated the growth of clean technologies such as electric vehicles and solar power.[34,35] And while policy support for the electrification of transport suffered a blow through the Trump administration's roll-back of climate policies, this does not necessarily mean a shift in the long-term policy direction across the globe. As in China, net oil importers including the EU and emerging markets across Asia and Africa have a strong incentive to promote electrification to improve the trade balance and insulate economies from commodity price shocks—an imperative highlighted by recent market shocks. And as the impacts of climate change become ever more evident across the world, policymakers are also likely to face further pressure to accelerate policies to reduce emissions.

[34] Rocky Mountain Institute. The CleanTech Revolution. June 2024.
[35] Way et al. Empirically grounded technology forecasts and the energy transition. September 21, 2022.

Recent oil supply shocks may further accelerate the energy transition

At the same time as these structural changes have unfolded, the market has also experienced significant volatility, first through the demand shock of COVID-19, and then through major supply-related shocks due to Russia's invasion of Ukraine and the Iran conflict.

Sanctions on Russian oil in 2022 and the blocking of the Strait of Hormuz in 2026 both caused spikes in global oil prices over USD100 per barrel, prices not otherwise seen since 2014. This type of volatility may seem to make the case for ensuring that additional sources of oil supply can get to market. However, their long-term consequences suggest the opposite impact on the need for future crude supplies and oil prices.

Short-term demand destruction is a typical impact of energy price spikes, with energy consumption falling in response to higher prices. The ongoing energy transition, however, brings additional responses into play due to the availability of viable and cost-competitive alternatives to fossil fuel for energy. After Russia's full-scale invasion of Ukraine, the EU responded with measures not only to diversify away from Russian gas and to save energy, but also to accelerate clean energy.[36] In recent months, governments around the world have introduced a range of measures promoting electrification in response to the oil price shock.[37]

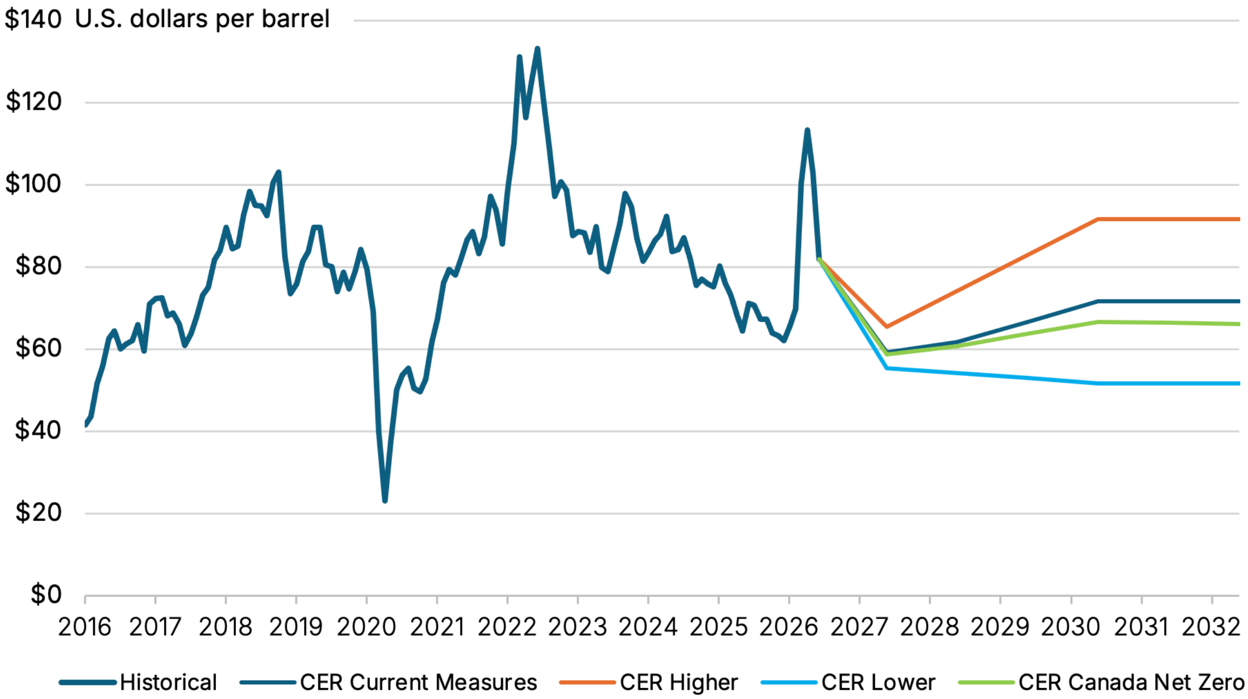
In addition, the pass-through of higher oil prices to consumer fuel prices improves the relative cost competitiveness of electric vehicles and other clean technology, supporting demand growth. Analysts at Goldman Sachs estimated that the share of electric vehicles in global car sales rose 3.4% to 26.1% from February to May 2026.[38] May and June saw Indian passenger EV sales increase by 95% year-on-year, with the electric share of overall sales increasing to 7.2% from 4.7% a year earlier.[39,40]

As investments in clean energy technology such as EVs displace oil demand for the life of those assets, short term shocks could further accelerate the energy transition through the long term. Far from making the case for new long-term oil infrastructure, oil supply shocks today may reduce the long-term demand trajectory by spurring electrification, and this impact makes it less likely that the world will see higher long-term oil prices in the future.

---

[36] European Commission. REPowerEU – Four Years On. 2026.
[37] IEA. 2026 Energy Crisis Policy Response Tracker – Structural Policies. Accessed July 2026.
[38] Yahoo Finance. Rising Electric Vehicle Sales Challenge Oil Demand Outlook. June 22, 2026.
[39] Federation of Automobile Dealers Associations (India). Electric Passenger Vehicle Retail Sales Jump 108% to 31,823 Units in June. July 7, 2026.
[40] The New Indian Express. EV Sales Across Categories Hit Fresh High in May 2026. June 9, 2026.

Brent oil price history and CER scenarios, adjusted to constant 2025 dollars

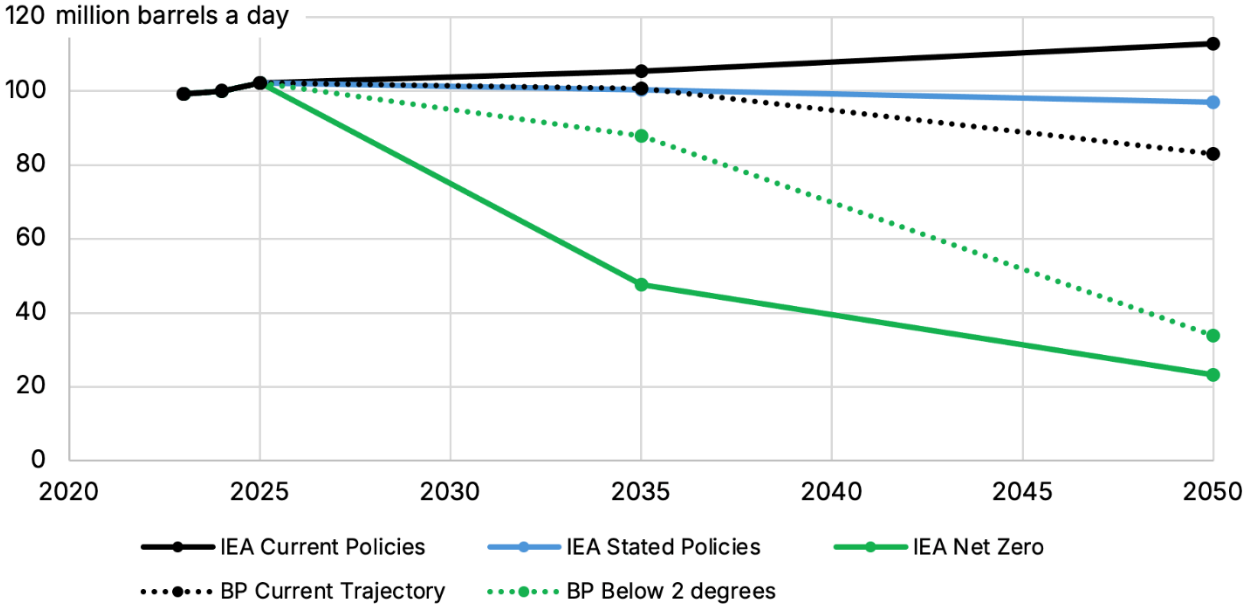


Sources: US Energy Information Administration, CER, Authors' analysis; IEEFA.

These market dynamics have significant implications for planning based on the CER's different outlook scenarios. The CER scenarios for oil output depend on global oil price assumptions and modelling of how much production would be globally competitive at those prices. Although those price scenarios are not explicitly linked to global demand scenarios, comparison with outlooks such as those from the IEA can suggest what future oil market scenario is likely to yield such prices and the related level of Canadian oil output.

The Current Measures scenario assumes a long-term global oil price of USD75 per barrel (in 2025 prices), similar to the price trajectory modelled by the IEA in its Stated Policies Scenario. The prices used in the Higher Scenario of USD95 per barrel align more closely with scenarios that see long-term global oil demand growth, such as the IEA's Current Policies Scenario, which assumes EV growth flatlines in markets like the United States and India. The CER's Lower Scenario assumes prices of USD55 per barrel, which while lower than the Current Measures, are still significantly higher than the IEA's Net Zero Scenario (USD25 per barrel in 2050), suggesting this price level might result from a more gradual decline in global oil demand.

Global oil demand scenarios



Sources: IEA, BP; IEEFA.

The potential combined effects of technological progress, increased cost competitiveness, and policy make it more likely that instead of plateauing, the coming decades could see the oil market experience structural decline.

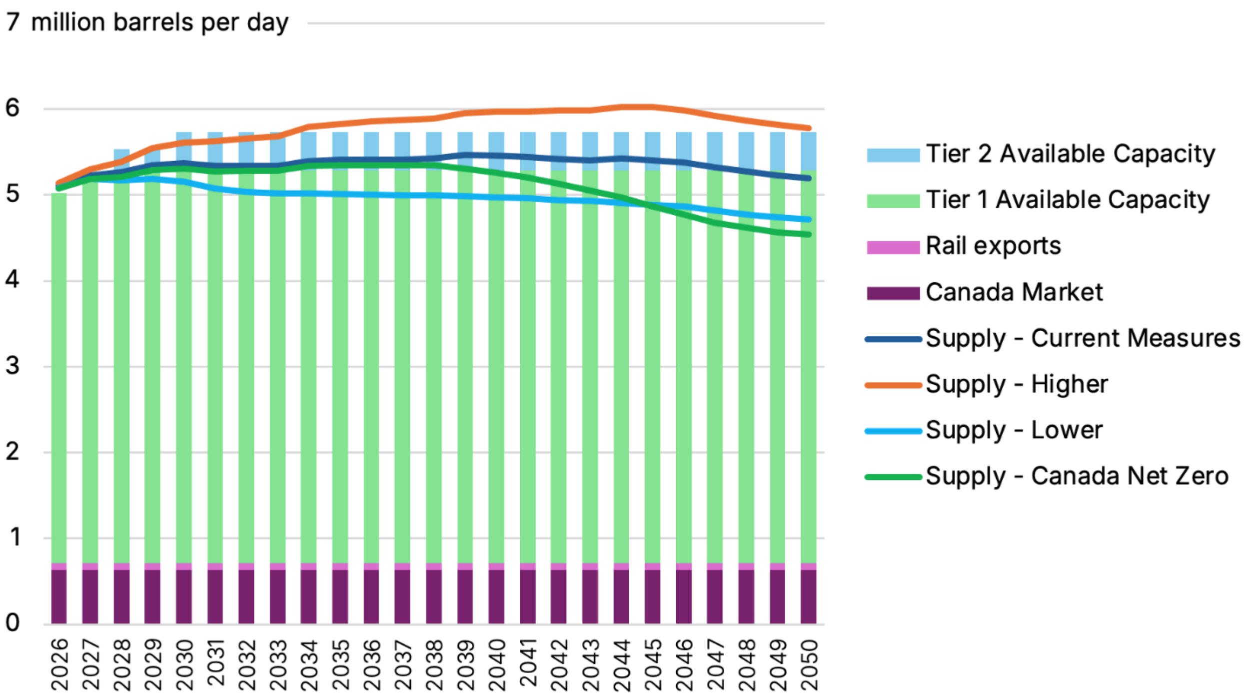
With the transition bringing cost-competitive alternatives that effectively cap long-term oil prices, scenarios like the CER's Higher Scenario appear less likely. The potential for acceleration of the transition instead makes it more relevant to consider scenarios aligned with global climate action, such as the IEA's Net Zero Scenario or BP's Below 2 Degrees scenario.

At the same time, China's leadership in the transition also makes it particularly important for a project focusing on supplying the Asian oil market to consider how transition dynamics may affect the region's demand for oil.

Forecasted crude supply for cross-border export from Western Canada is unlikely to exceed existing plus Tier 1 and Tier 2 planned export pipeline capacity

A central question in evaluating the need for additional export infrastructure is whether projected production will exceed the capacity of existing and planned egress systems. To assess this, CER's projections of crude oil supply from Western Canada are measured against existing and proposed egress capacity. Adjustments were made to the CER data to isolate only those volumes from Western Canada that would realistically require access to cross-border pipeline capacity. The analysis factors only Tier 1 and Tier 2 proposed expansion projects that are either approved, under construction, or have reached FID, and applies an effective pipeline utilization rate of 98% to better reflect real-world operating conditions. All Tier 3 projects are excluded from the quantitative capacity assessment.

Western Canada oil supply scenarios and egress capacity



Sources: CER, Author's analysis; IEEFA.

The analysis reveals that existing capacity and near-term expansions address capacity deficits in all CER scenarios except the Higher Scenario. Existing export infrastructure provides approximately 4.57 thousand bpd of effective cross-border export capacity after adjusting for utilization. Comparing this with supply available for export shows that production is fully supported under the Lower Scenario. Some capacity deficits occur within the next few years in all other scenarios. The Current Measures and Higher Scenarios have persistent egress capacity shortfalls reaching a peak of roughly 180,000 bpd by 2040 for the former and about 740,000 bpd by mid-2040 for the latter. The Canada Net Zero scenario also experiences some minor deficits (sub 60,000 bpd). It is also worth noting that some spare capacity above average annual supply is likely required due to the seasonality of oil sands production, which has meant that maximum monthly output significantly exceeds the average by around 10% over the past 10 years. However, the capacity outlook changes materially when Tier 2 expansion projects are factored. Collectively, these projects add approximately 550,000 bpd of incremental export capacity to Western Canada's cross-border export system and provide enough egress to support production under all scenarios except the Higher Scenario. Under the higher production outlook, the incorporation of Tier 2 projects significantly narrows recorded deficits and delays the emergence of capacity constraints by about a decade. Capacity shortfalls emerge by the mid-2030s and reach a peak of 290,000 bpd by the mid-2040s.

The data also shows that brownfield expansion projects are capable of fully addressing all egress capacity deficits in all scenarios. CER's future egress requirement projections can be met through incremental expansions of existing systems. The Higher Scenario presents the greatest challenge to existing egress capacity and may require the advancement of additional expansion projects. In this case, proposed projects like the South Bow Prairie Connector initiative, if advanced, could easily accommodate observed deficits. Brownfield expansion projects benefit from lower capital requirements, shorter development timelines, and reduced regulatory and environment hurdles. Therefore, they represent a more commercial and operationally realistic pathway for addressing future egress requirements without saddling taxpayers and public accounts with material risks.

While historic arguments for new export infrastructure focused on the existence of egress constraints, pipeline bottlenecks, and the consequent widening of the WCS-WTI differential, our capacity assessment presents a different picture. Given that existing and brownfield expansion projects are largely capable of accommodating projected production growth—at presumably lower costs and with higher degrees of execution certainty—no capacity-driven need exists for construction of a new large-scale export corridor. The large scale of the proposed West Coast Oil Pipeline—which would nearly double the capacity added by the entire group of Tier 2 expansion projects—substantially exceeds all identified shortfalls.

The economic benefits of the West Coast Oil Pipeline are likely outweighed by its costs

Having determined that the proposed West Coast Oil Pipeline does not appear necessary based on scenarios for future supply, the next question for discussion is whether the strategic, commercial, and market access benefits of the pipeline justify the costs and risks associated with its development. Accordingly, this section examines the economics and competitiveness of the proposed export corridor and other relevant value considerations.

The West Coast Oil Pipeline's tolls are likely to be significantly higher than those of existing pipelines

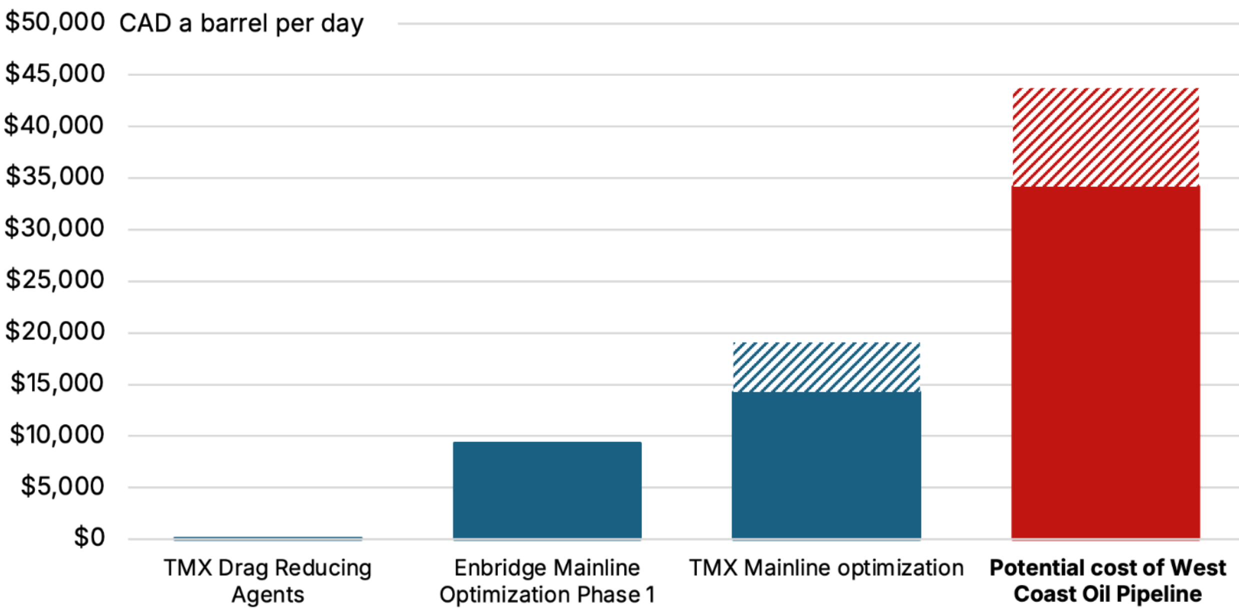
In its July 2026 submission to the Major Projects Office, the government of Alberta offered a cost estimate of CAD35.2-43.7 billion (in today's prices) for the West Coast Oil Pipeline. The low-end cost estimate assumes rapid progress is made, with FID taken in Q1 2028 and the pipeline online in 2032, while the higher cost is noted to assume no regulatory reform, with FID in Q4 2029 and the project online in 2034.

This cost estimate is up to 45% higher than the cost of TMX, which added 590,000 bpd capacity at a cost that ballooned to around CAD30 billion (excluding financing costs).[41,42] The submission notes that at CAD35,200-47,300 per bpd of capacity, the West Coast Oil Pipeline would cost less per barrel of capacity than TMX, which translates to CAD59,800 per bpd at current prices. Under the contractual framework agreed for TMX, however, tolls are only adjusted to recover a portion of cost overruns—the tolls charged to oil shippers are based on a much lower cost of around CAD15 billion.[43] Also, TMX costs were recovered through contracts covering most of the entire 890,000 bpd capacity of the pipeline, rather than just the expanded capacity. This means that the cost relevant to shippers on TMX per bpd of capacity is around half the low-end estimate for the West Coast Oil Pipeline.

[41] Canada Development Investment Corporation. Annual Report 2025. 2026.
[42] Kinder Morgan. Form 10-Q Quarterly Report. 2025.
[43] Canada Energy Regulator. CER sets interim tolls for expanded Trans Mountain Pipeline System. November 30, 2023.

This cost range is also significantly higher than the reported costs of upcoming expansions. The two expansion projects included in our tier 1 capacity outlook—TMX Drag Reducing Agents and Enbridge's Mainline Optimization Phase 1—are expected to cost CAD100 and CAD9,333 per bpd capacity, respectively. Official estimates for other proposed expansions have not yet been given, but a reported estimate of CAD3-4 billion for the TMX Mainline Optimization gives an approximate range of CAD14,000-CAD19,000 per bpd capacity.

Cost of new capacity, West Coast Oil Pipeline vs selected expansion projects



Sources: Authors' analysis; IEEFA.

While Canadian pipelines and their tolls are regulated, tolls for oil export pipelines are essentially negotiated settlements between developers and shippers, which must then be approved by the CER.

To finance a new pipeline, a developer typically agrees to long-term contracts with shippers covering enough throughput to give confidence in achieving a fair rate of return on investment. As shown in the table below, the TMX[44,45] and Keystone XL[46] projects saw shippers (mostly oil sands producers) commit volumes covering around 80% of capacity for 15-20 years. Under this model, committed shippers are responsible for paying tolls for their committed volume for the duration of their contracts. The remaining capacity is allocated to the spot market, but with tolls charged at a premium to those for committed shippers. The TMX and Keystone XL toll structures included provisions for revenues on this remaining capacity above a threshold to be shared with committed shippers,

[44] National Energy Board. Reasons for Decision – Trans Mountain – Tolls and Tariffs (RH-001-2012). May 2013.
[45] Trans Mountain Pipeline ULC. 2026 FCOS Application – Settlement Filing. July 2026.
[46] TransCanada Keystone Pipeline GP Ltd. Commercial Terms and Tolls (Tab 5), Appendices 5.1–5.3. 2013.

essentially limiting excess returns for the developer and providing additional reward to committed shippers for signing long-term agreements.

Table 3: Shipper commitments and terms on TMX and Keystone XL pipelines

	TMX[45, 46]	**Keystone XL**[47]
Committed volume and period	80% of capacity, under 15-20-year contracts.	76% of capacity with average 17-year term.
Toll structure	Fixed toll escalating at 2.5% per year covering all except power and uncontrollable costs, which are recovered through variable toll. Uncommitted shippers charged at 10% premium to 15-year committed fixed toll.	Flat fixed toll over contract period to recover invested capital. Variable toll to recover operations, maintenance and administrative expenses. Uncommitted toll proposed at maximum of 120% of total 10-year committed toll.
Revenue sharing	0% of all revenue from uncommitted shippers on volumes over 85% of available capacity shared with shippers.	N.A.
Cost risk allocation	Costs grouped into 'capped' costs, for which fixed tolls are fixed based on 2017 cost estimate and 'uncapped costs', for which tolls rose based on actual costs.	75% of cost.

Source: IEEFA.

The level of investment return targeted by pipeline developers when making an investment decision would be a decision for individual companies based on their strategy, financial position, and view of the level of risk. Regulatory filings around TMX, however, give insights into these financial decisions. In response to an information request on their 2012 regulatory application for TMX service and tolls, Trans Mountain stated that they were "making an investment decision based on a return on investment that is acceptable to Trans Mountain and its owner taking into account the cash flow generated by the negotiated tolls that were agreed to by Trans Mountain and Committed Shippers," and that then Trans Mountain owner Kinder Morgan "targets its unlevered rates of return for pipeline infrastructure investments over their economic life in a typical range of 12% to 15%."[47]

[47] Canadian Association of Petroleum Producers. CAPP IR Response – Revised January 10, 2013. January 2013.

In this analysis, we use the investment thresholds and the toll structure negotiated for TMX as the basis on which to model the potential tolls that are likely to be required for the West Coast Oil Pipeline to go ahead. The key elements of the model structure are as follows:

- 80% of capacity committed under 20-year contracts
- Negotiated fixed toll that escalates at 2.5% annually after the first year
- Targeting 12% pre-tax unlevered rate of return based on cash flows from committed volumes and an assumed cost-of-service toll for the remainder of 40-year useful life

Testing our model against TMX's expected tolls—using the 2013 cost estimate of CAD5.5 billion;[48] CAD229 million fixed component operating costs in year 1;[49] and committed volumes for 80% of capacity over 20 years—results in an initial fixed toll of CAD3.70 per barrel. This is in line with the 2013 negotiated fixed toll of CAD3.60-3.90 per barrel (Edmonton to Burnaby toll for 20-year contracts depending on volume of commitment),[50] which suggests that the model is a fair representation for toll-setting behavior.

Applying this toll-setting model to the proposed new pipeline using the cost estimates provided by the Alberta government yields an initial fixed toll in 2032 of CAD18.70 (CAD16.28 in 2025 dollars) if the project cost is CAD35.2 billion (2026 dollars), or CAD23.72 per barrel (CAD19.83 in 2025 dollars) initial fixed toll in 2034 if the project cost is CAD43.7 billion (2026 dollars).

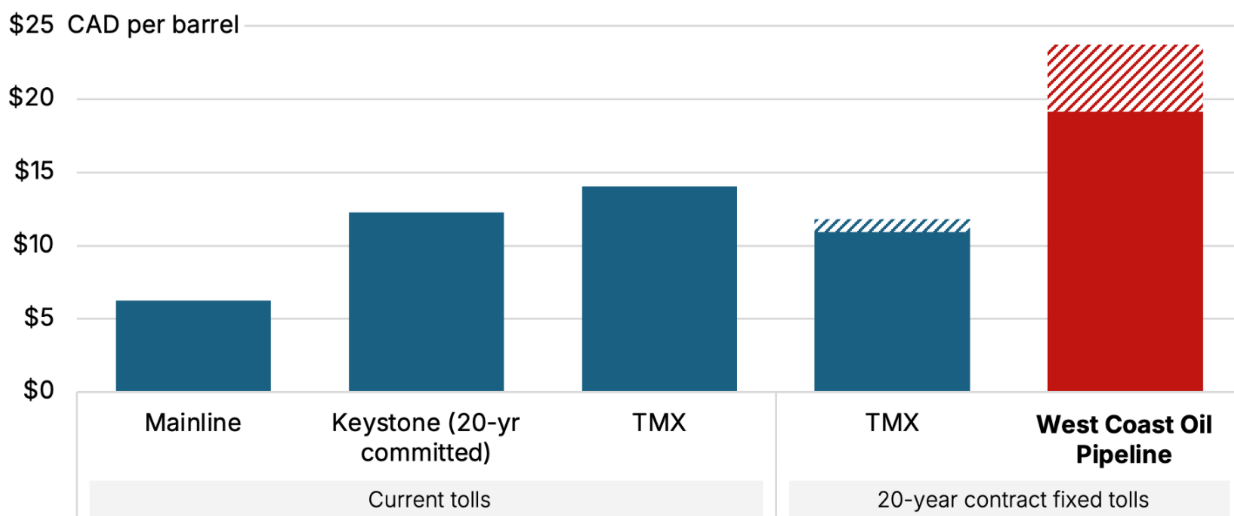
Even if project costs for the proposed pipeline are at the low end of the cost range, tolls would be 60% higher than those paid by committed shippers exporting via TMX, or 36% higher than the higher uncommitted TMX toll. At the high end of the cost estimate, fixed tolls would be almost double those charged on TMX. TMX tolls today are higher than those paid by shippers using pipelines to the United States such as Enbridge Mainline and Keystone—meaning that the proposed pipeline would likely be the highest-cost pipeline export route by far.

The proposed pipeline at a CAD35.2-43.7 billion cost range would therefore significantly increase the average cost of export of oil from Alberta. Although investments required for expansion of existing pipelines may impact tolls, the much lower cost of these capacity additions compared to the West Coast Oil Pipeline proposal means this toll differential is likely to remain significant.

[48] Trans Mountain Pipeline ULC. NEB Application – Revised January 10, 2013. January 2013.
[49] Trans Mountain Pipeline ULC. Indicative Toll Scenario A – Cases 8–12. 2013.
[50] Trans Mountain Pipeline ULC. Application for Interim Commencement Date Tolls. June 1, 2023.

Increasing the contracted share of capacity from 80% to 90%—as has recently been proposed for Trans Mountain—could reduce tolls, but only by 11%, leaving them still significantly higher than those on other routes. As the primary project proponents are government entities, reducing target rates of return below those that private investors would accept could be another potential way to reduce tolls. Combining a reduction in the target rate of return to 10%, and a 90% contracted share of capacity, could reduce tolls around 25%, but again this would still leave tolls on the proposed pipeline higher than those on existing routes. It would also leave the project investors with less margin to absorb any potential cost overruns.

Current uncommitted tolls and 20-year contract fixed tolls (2034)



Sources: Authors' analysis, public toll document; IEEFA.

The West Coast Oil Pipeline is unlikely to be necessary to avoid reliance on high-cost rail exports

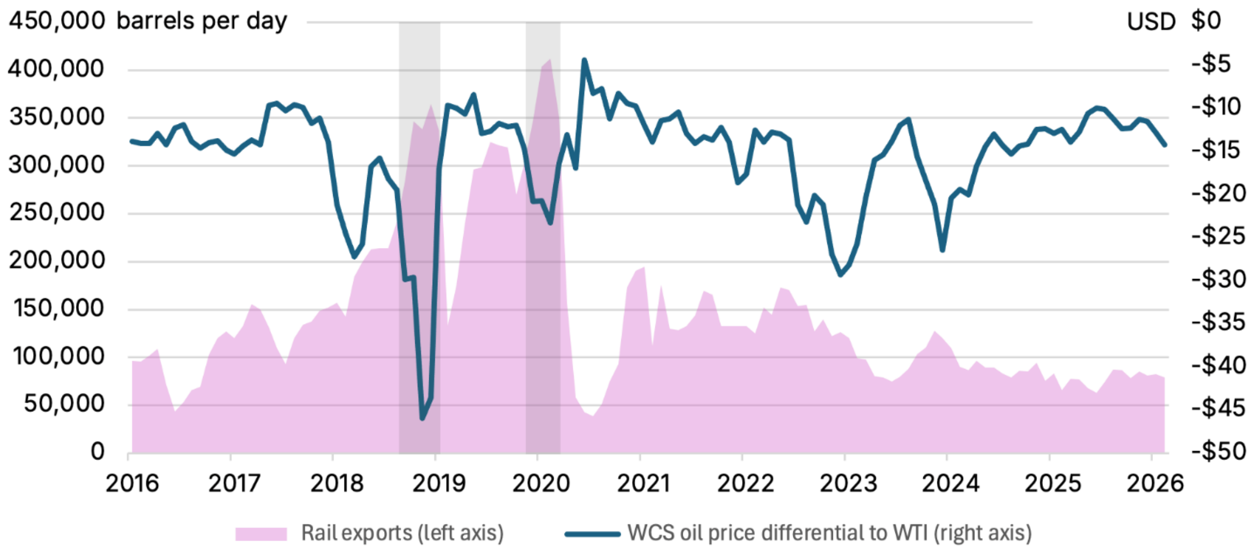
The toll commitments modelled above essentially model the cost of the proposed pipeline to the industry and can act as a benchmark against which to measure potential economic benefits. The suggested benefits are of three key types:

1) Alleviating the risk that the WTI-WCS differential widens due to pipeline constraints as production grows;
2) Price benefits to the sector from improved access to diversified export markets; and
3) Direct added value for oil exports routed through the pipeline.

A core argument made in favor of the West Coast Oil Pipeline is that without additional capacity, the differential between WTI and WCS prices at Hardisty would widen significantly, affecting the overall value of the Western Canadian Sedimentary Basin sector. The differential between WTI and WCS at Hardisty is determined both by the quality of the crude and the cost to transport it to market.

As export by rail typically costs more than by pipeline, the differential has historically seen significant widening when pipeline constraints hit and more crude has to move by rail or be stored in Alberta.[51] A notable example of this occurred in late 2018, when prices dropped to a near 90% discount to WTI, and in late 2019, as highlighted in the chart below. The Canadian Association of Petroleum Producers (CAPP) has urged that "this loss of revenue results in lower government royalties and GDP," advocating that "Expanding pipeline capacity to B.C.'s West Coast would significantly reduce transportation differentials by providing the shortest and most cost-efficient access to tidewater."[52]

Monthly oil exports via rail, and the WCS-WTI differential



Sources: CER, Government of Alberta; IEEFA.

If no additional pipeline capacity were built beyond those which have already reached FID, all the CER's scenarios except for the Lower Scenario would indicate increased rail exports, which would risk a widening of the WCS-WTI differential and lost industry revenue.

The requirement for additional capacity to avoid such an outcome, however, comes in the late 2020s, which is several years before the earliest date that the proposed West Coast pipeline is supposed to come online. This changes the picture significantly: if the expansions considered in our Tier 2 category go ahead to meet this requirement, only the Higher Scenario carries risk of takeaway constraints that could widen the WCS-WTI differential.

While the Higher Scenario would require more pipeline capacity to avoid the risk of the WCS-WTI differential widening, this only means producer prices would likely benefit in that scenario from new pipeline egress capacity to ease constraints. It does not necessarily indicate that new capacity is best routed to the Pacific market over any other of the Tier 3 projects. It is therefore important to assess

[51] Canada Energy Regulator. Market snapshot: Canadian crude by rail exports hit 13-year low. April 8, 2026.
[52] Canadian Association of Petroleum Producers. Understanding the WCS–WTI Differential. April 2026.

the question of whether increased access to the Pacific would materially improve the price of WCS for Alberta's oil sector.

The WCS-WTI differential is unlikely to be improved by the proposed pipeline

With pipelines charging their own tolls and serving different markets, the price of WCS at Hardisty depends on the netback value (price minus transportation cost) that can be achieved by the marginal barrel (the last to clear the market). While in cases where producers ship and sell their barrels at the destination market the value relevant to them is the actual netback from that sale, many sales will be priced based on the WCS price at Hardisty, making this market benchmark important to the sector. To assess the potential implications for WCS prices related to building a new pipeline to the Pacific, we therefore built an illustrative demand curve from the potential netbacks available from each export route.

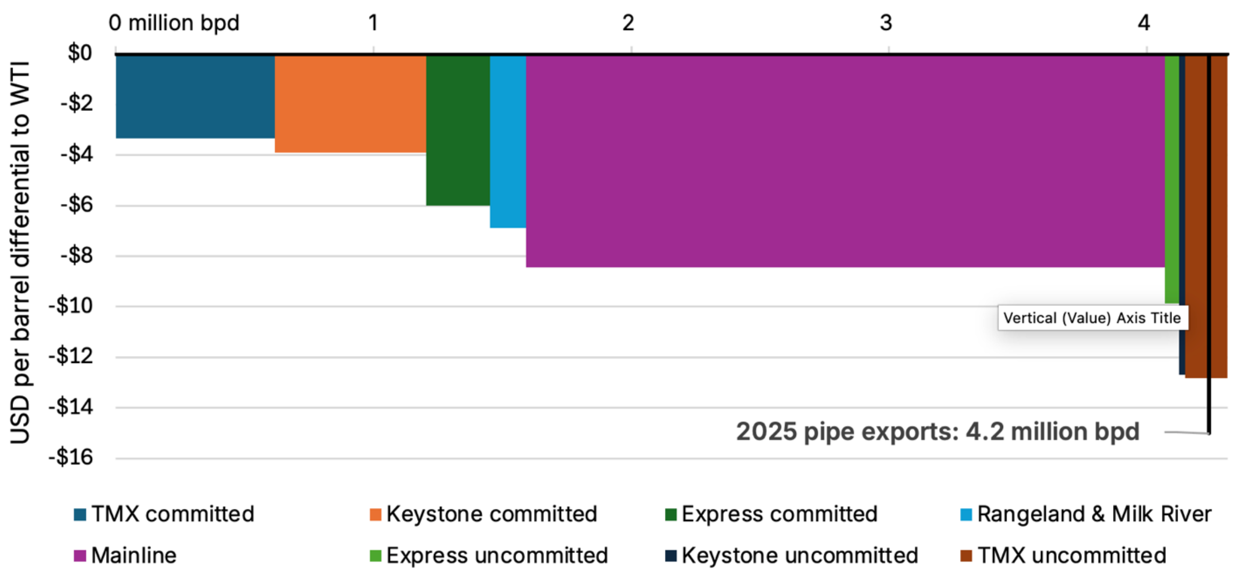
Assuming producers and shippers act to optimize their profits, export capacity is used in order of the value that they offer, with the routes offering the highest netback used first. Marginal netback prices for each route are calculated as the sales price that can be achieved at the destination, minus marginal transport costs. Destination sales prices for Pacific coast exports are based on reported value of exports towards China, while for the United States they are based on the price of imported crude purchases by refineries in U.S. destination regions and market differentials for WCS at Houston.

As the fixed tolls under long-term contracts are a sunk cost (one that must be paid whether or not the capacity is used), the cost for committed shippers to use their contracted capacity is represented only by the variable toll. This means that capacity under long-term contracts has a higher "marginal netback" excluding sunk costs and sits relatively high up the netback curve. In contrast, for uncommitted capacity the marginal transportation cost is the full spot toll. It should be noted therefore that the "marginal netback" represented in the following charts for the "committed" portions of pipeline capacity are not a full representation of the true netback for shippers. Full details of the assumptions for destinations and marginal transportation costs are available in Appendix 1.

The following chart shows the marginal netback curve based on current capacities and tolls. Where the supply intersects this curve indicates what route should set the WCS Hardisty price; exports flow through routes to the left of this point, while those to the right are not used. Average pipeline export flows from 2025 intersect the tranche of TMX capacity available for uncommitted shippers, suggesting this route was the typical price setter, as this would be the lowest netback export route that is required to clear supply. This may have varied throughout the year based on price movements in different markets, and in the higher-output winter months prices are likely to have been set by lower netback routes or rail. While this is a simple model that does not account for seasonality or additional market and transportation costs, its results map relatively closely to the actual WCS

Hardisty differential in 2025, which ranged from USD10 per barrel in June to USD13 per barrel in March.

Hardisty marginal netback curve by pipeline export route, current



Source: Authors' analysis.

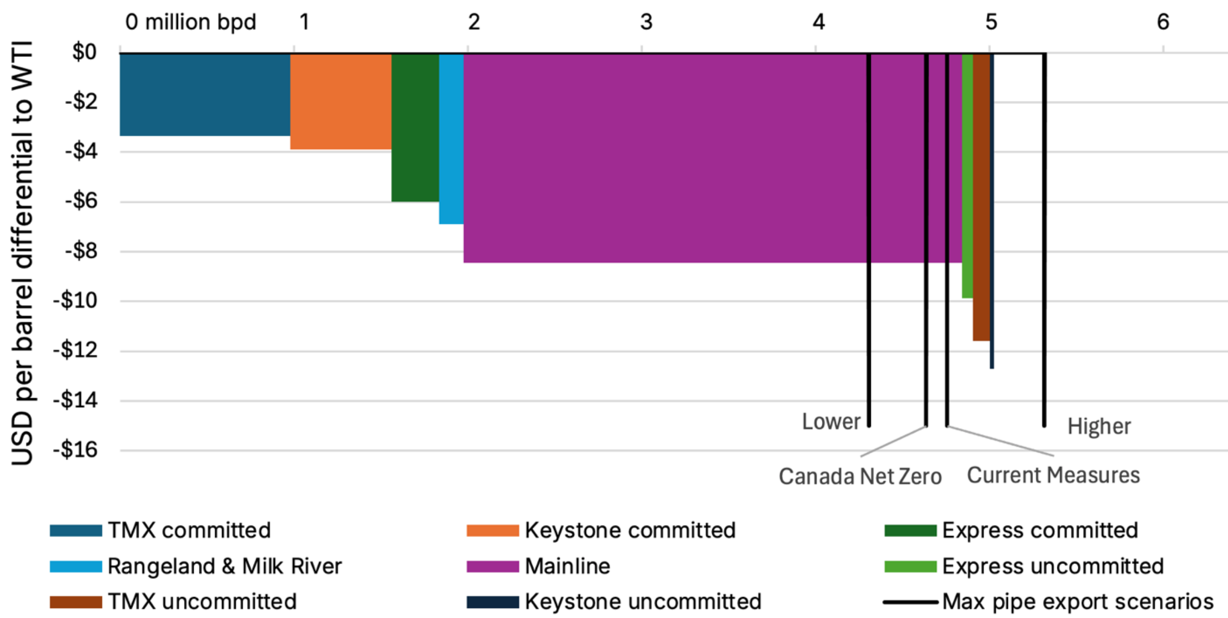
In recent years, prices for exports to Asia at Canada's Pacific coast appear at times to have been higher than those for Canadian heavy crude in the United States.[53] Exports to China in 2025 were valued according to customs data at an average discount to WTI of USD2.77 per barrel, compared to USD4 per barrel discount to WTI reported for Canadian imports purchased by refiners in the U.S. Midwest (PADD 2). The WCS-WTI differential narrowed after TMX came online in 2024, and while our model sees TMX as the typical price setter in 2025, this doesn't mean that higher prices at the delivery point of TMX translated to WCS. The driver for WCS prices at Hardisty is the netback price at the margin after transportation costs. Even with a price premium at the Pacific export point, high TMX tolls mean its netback using uncommitted capacity (the netback which would set the price) is the lowest of all pipeline export routes. The narrowing of the WCS-WTI differential appears to result primarily from the market no longer clearing only through higher-cost rail routes.

Casting this model forward to assess exports in our future scenarios suggests that that this same impact on the WCS-WTI differential may not be repeated. Assuming pipeline capacity is used in the order of the netback that can be achieved, if Tier 2 expansions go ahead but with no further capacity additions, the typical price setter in all scenarios except the Higher Scenario would become Enbridge Mainline exports to Chicago. As this is a higher netback route than the current price setter, this would mean the Tier 2 expansions would result in some further improvement to the WCS-WTI differential. However, the West Coast Oil Pipeline does not offer further improvement to the WCS-

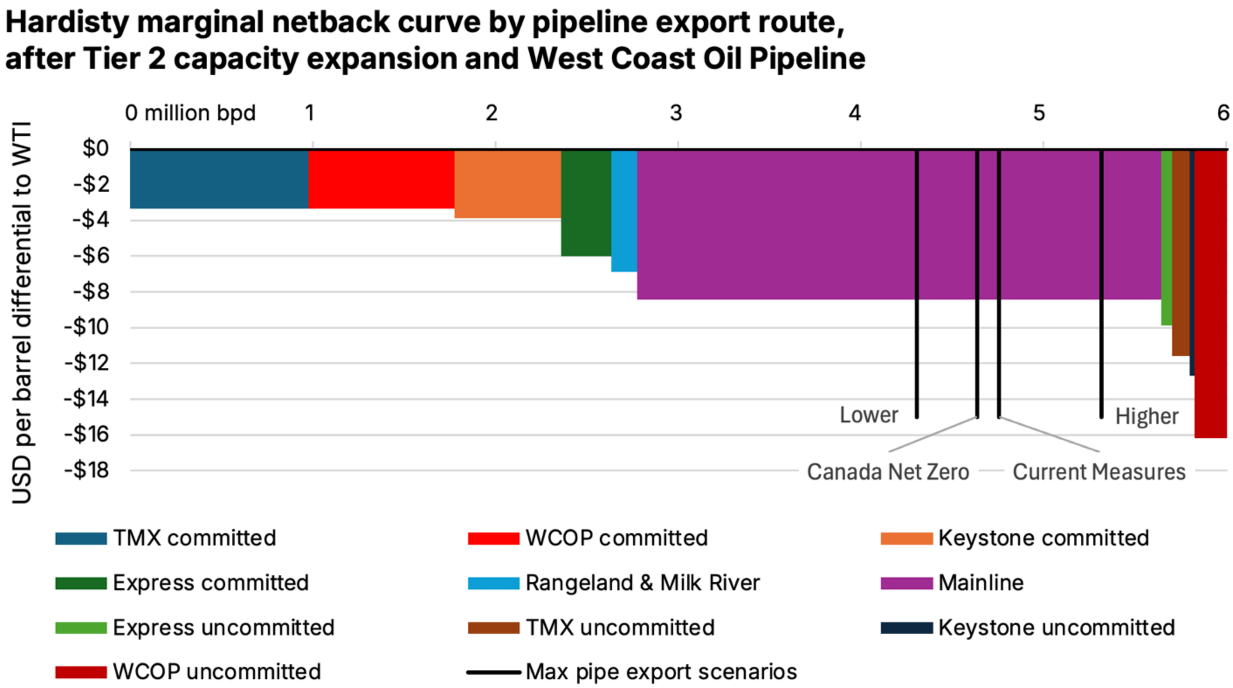
[53] RBN Energy. China Syndrome – Canada's West Coast Heavy Oil Exports Fetching Greater Value Than From the U.S. Gulf Coast. October 20, 2025.

WTI differential. The sunk cost nature of tolls on its committed capacity mean that capacity would likely be filled, but while fewer barrels might be exported through the Enbridge Mainline as a result, the addition of the proposed pipeline does not change the marginal route and the price. Its high tolls mean that the uncommitted portion of its capacity lies at the end of the demand curve due to much lower potential netbacks.

Hardisty marginal netback curve by pipeline export route, after Tier 2 capacity expansion



Source: Authors' analysis; IEEFA.



Source: Authors' analysis; IEEFA.

As discussed above, new capacity would be needed under the Higher Scenario to avoid the risk that the higher cost of rail exports or storage widens the WCS-WTI differential. But as the long-term contracted capacity of any new pipeline (80% under our assumption) is high in the ranking of routes by marginal netback, rather than at the margin, WCS prices are likely to be set by an existing pipeline. The export market (whether via the United States or the Pacific) of a new pipeline thus becomes less relevant to WCS prices, as the new route is unlikely to be the price setter.

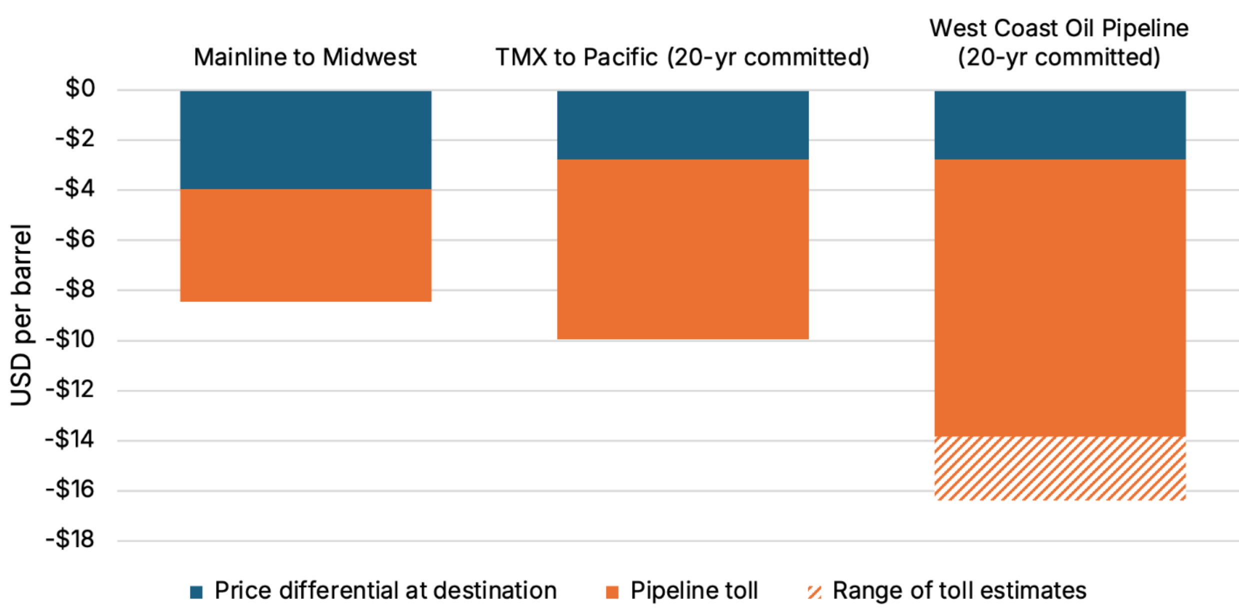
The finding that the West Coast Oil Pipeline is unlikely to have a significant impact on the WCS-WTI differential (assuming sufficient alternative capacity addition in the Higher Scenario) has additional significance beyond the lack of upside to industry value per barrel. It also means that the project is unlikely to offer a boost to supply growth through the impact that a lower differential could have on the viability of new projects.

Any premium for barrels exported through the West Coast Oil Pipeline appears unlikely to compensate for higher tolls

Even if WCS prices may not be set by a Pacific pipeline, the question remains whether the project can offer an upside to exports, particularly if prices at the Pacific Coast are sometimes higher than those in the United States. The value upside from a tidewater pipeline would be the difference in netback earned by producers exporting through the proposed pipeline compared to what they would have earned through an alternative export route.

As discussed above, due to the West Coast Oil Pipeline's high tolls, only the committed portion of its capacity would be used across scenarios. Assuming a premium for deliveries at the Pacific Coast compared to the U.S. Midwest persisted at USD1.19 per barrel (based on the 2025 delivered prices used above), the final netback for committed shippers using the West Coast Oil Pipeline would be significantly lower than this alternative route. As tolls would be much higher than those on the Mainline, shippers using the proposed pipeline would make USD5-8 per barrel (in 2025 prices) less than if they had exported via the Mainline to the United States. This translates into the proposed pipeline causing an annual drag on industry profits of CAD2.2-3.2 billion for the 20-year contract period. And while price movements could change relative netbacks, a high enough Pacific delivery premium to offset the difference in tolls appears highly unlikely given the availability of competing heavy oil supply to Asia.

Netback per barrel, differential to WTI for West Coast Oil Pipeline, Mainline, and TMX



Source: Authors' analysis.
Note: Tolls in chart use proposed 2027 tolls for TMX and adjust West Coast Oil Pipeline tolls to 2025 prices for comparability.

In the Higher Scenario the cost-benefit analysis is different, as some new capacity is likely needed to avoid pipeline constraints. The two potential scenarios to be compared are therefore capacity relief via the West Coast Oil Pipeline and relief via alternative additional pipeline capacity.

The widest 2025 premium between prices at the Pacific coast and in the United States based on our analysis would be USD3.23 per barrel versus delivery to Rocky Mountains, PADD 4. If this maximum differential stayed constant in real terms (only increasing with inflation), then deducting it from the estimated West Coast Oil Pipeline tolls would mean that an alternative pipeline delivering to the United States would offer greater value to the industry as long as its tolls were below CAD14-18 per barrel (in 2032 or 2034 based on the low- or high-cost estimate).

This analysis simplifies market dynamics but it provides useful insights into price-setting dynamics and whether a new Pacific export route can add value. In reality, heavy oil price differentials between markets would depend on demand and supply dynamics for those markets—for example, the diversion of heavy oil exports from the U.S. market to Asia may narrow the differential through greater supply availability putting downward pressure on prices in Asian markets and have the opposite effect in U.S. markets. Other factors such as refinery market constraints; differing export dynamics for heavy vs. light crude; market frictions; shorter term dynamics and constraints; variations in netback within pipelines based on origin and delivery points; and marketing arrangements may also influence prices and netback.

Conclusion

The oil sector plays a major role in the economy of Alberta and Canada, and decisions around its future must account for a complex landscape of issues. The global energy sector is undergoing significant changes, and both the ongoing trade war with the United States and the economic effects of the current Iran conflict have highlighted the importance of economic diversification. At the core of any case for new export infrastructure lies the question of whether it is needed to unlock supply and what value it can generate. This analysis finds that the proposed West Coast Oil Pipeline does not live up to this core case, with wider benefits around diversification or other objectives stacking up against considerable costs.

Alberta's oil producers face a significant planning challenge to ensure that they can access export markets competitively. For major export pipelines to be financed, they likely need to commit to using capacity under long-term contracts and that may come ahead of them committing to the upstream investments supplying the oil. This decision-making comes amid a picture that may then be altered by global market impacts on the competitiveness of new supply, other producers' decisions, and delays to infrastructure projects. Our analysis suggests that the large commitments required to support the West Coast Oil pipeline may harm rather than secure future returns for investors.

Public investment can often be a crucial aspect in supporting strategically important industries facing uncertainty. But the wider market conditions that would be required to support rapid output growth are far from certain and the global energy transition appears to make them less likely. Even if output does grow rapidly, there are other potential options for capacity addition with shorter lead times that may be better suited for an uncertain outlook. In this context, the potential benefits of oil export market diversification should be carefully weighed both against the infrastructure cost and against alternative investments that might offer wider economic resilience to the energy transition.

Appendix 1: Economic modelling methodology and assumptions

The authors developed a financial model to calculate the fixed toll on long-term contracted volumes that would be required to achieve industry-level returns on the West Coast Oil Pipeline. Given a set of financial assumptions, this model divides the sum of all discounted costs, minus assumed revenues after the contract period, by the sum of the discounted contracted volumes (adjusted for toll escalation), to yield the initial fixed toll.

Table A 1: Assumptions for West Coast Oil Pipeline toll modelling

Factor	Assumptions
Long-term contracted volumes	800,000 bpd (80% of capacity) over 20 years. 90% sensitivity also modelled
Capital expenditure	CAD35.2-43.7 billion, as in government of Alberta's submission to Major Projects Office
Operating expenditure	Assumed at same level as Trans Mountain's reported 2025 operating costs: CAD479 million (excluding fuel and power as recoverable through variable tolls),[54] adjusted annually for inflation
Cost inflation	Assumed at 2% per year. Capex is only inflated up to the year of first capex
Annual toll escalation	2.5%
Year pipeline online	2032 or 2034, as in government of Alberta's submission to Major Projects Office
Target rate of return used for discounting	12% (10% sensitivity also modelled)
Tolls after expiration of long-term contracts	Assumed to revert to cost-of-service model for remainder of 40-year asset life with following assumptions: Annual depreciation: 2.5% based on 40-year lifetime Capital structure: 45% equity, 55% debt based on Trans Mountain deemed equity ratio Return on equity: 8.1%[55] Cost of debt: 5%[56] Note: Post-contract cost-of-service model has little impact on tolls, which increase by only 1% if these revenues are not accounted for

Source: Authors' analysis.

[54] Trans Mountain Pipeline ULC. 2026 Toll Adjustments – Attachment 3: Calculation and Reporting Schedules. March 2026.
[55] Canada Energy Regulator. Rate of Return on Common Equity per Discontinued RH-2-94 Formula for 2026. December 4, 2025.
[56] Ontario Energy Board. Cost of Capital Parameter Updates. Accessed July 2026.

Illustrative demand curves by export route were modelled using the following set of assumptions to determine route capacity and netback. As in the capacity requirement analysis, pipeline capacity utilization is limited to 98%. Fixed tolls for long-term committed shippers are considered sunk costs and not included. Currency conversions use the 2025 average exchange rate of 1.3978 CAD per USD.[57]

Table A 2: Price and toll assumptions for netback analysis

	Trans Mountain	Enbridge Mainline	Keystone	Express	Rangeland and Milk River
Discount to WTI at delivery point, in USD per barrel	2.77, based on average monthly discount to WTI for heavy oil exports to China in 2025[58]	3.96, based on average 2025 price paid by Midwest refiners for imported crude[59] (100% of imports were from Canada)[60]	3.90, based on average WCS Houston price differential to WTI[61]	6.00, based on average 2025 price paid by Rocky Mountain refiners for imported crude (100% of imports were from Canada)	
Capacity assumed under long-term contracts	80%, increasing to 90% from 2027	None	94%[62]	80%[63]	None
Heavy crude pipeline toll (based on current tolls)	Current: CAD5.1274 per cubic meter (m^3) variable toll. CAD83.3033/m^3 fixed toll for	USD28.2092/m^3 international joint toll rate (Hardisty to Flanagan, IL)[66]	USD8.80 per barrel international joint toll	CAD6.3986 /m^3 to U.S. border[68] and USD19.797 5/m^3 from	CAD4.20/m^3 to U.S. border[70] and USD0.4088 per barrel from border

57 Bank of Canada. Annual Exchange Rates. Accessed July 2026.
58 Statistics Canada. Canadian International Merchandise Trade Web Application. Accessed August 2026.
59 U.S. Energy Information Administration. Petroleum Prices: Refiner Acquisition Cost of Crude Oil. Accessed July 2026.
60 U.S. Energy Information Administration. PAD District Imports by Country of Origin. Accessed July 2026.
61 IEA. Oil Market Report – January 2026 (and 2025 releases). 2025–26. January 21, 2026.
62 Oil Sands Magazine. Pipeline Egress Outlook to 2030 – 2026 Edition. December 11, 2025.
63 Canada Energy Regulator. Canada's Pipeline Transportation System 2016 – Express Pipeline. 2016.
66 Enbridge Inc. Canadian Mainline Tariff (CDMN-CER-601 / FERC 45470). May 29, 2026.
68 Enbridge Inc. Express Canada Uncommitted Toll Schedule. February 27, 2026.
70 Milk River Pipeline Ltd. Milk River Pipeline Tariff No. 178. December 1, 2025.

	uncommitted shippers (Edmonton to Westridge toll)[64] 2027 onwards: CAD72.2798/m^3 fixed toll for uncommitted shippers, or CAD57.8586/m^3 for committed shippers under 20-yr ≥75,000 barrels per day contracts (Edmonton to Westridge toll)[65]	Hardisty to Houston[67]	border to Casper, WY[69]	to Laurel, MT[71]

Source: Authors' analysis.

[64] Trans Mountain Pipeline ULC. Interim Tariff No. 123. March 31, 2026.
[65] Trans Mountain Pipeline ULC. Application for Approval of Negotiated Settlement. July 7, 2026.
[67] South Bow Pipeline. CER No. 83 – South Bow IJT Rate Tariff. May 28, 2026.
[69] Enbridge Inc. Express US Pipeline Tariff (EXP-US-FERC-169.10.0-PLT). May 27, 2026.
[71] CHS Inc. Front Range Pipeline Tariffs. Accessed July 2026.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

About the authors

Mark Kalegha

Mark Kalegha is an IEEFA energy finance analyst who covers the oil and gas industry in Canada with a focus on project valuation, capital budgeting, and capital structure analysis for upstream, midstream, and downstream entities. He has worked for almost a decade as a finance professional in the upstream E&P space, authoring numerous reports as an equity research analyst. He has an MBA with a specialization in investment management.

Will Scargill

Will Scargill is an independent consultant working in collaboration with IEEFA. He is an economist with over a decade of experience in the energy and climate transition space. In addition to consulting on these issues, focusing on assessing the potential impacts of a global low-carbon transition on developing economies, he also holds a senior role providing climate risk advisory and consulting services in the investments industry. Will's work has included advising governments, central banks, major institutional investors, and energy companies on energy and climate related issues.

Institute for Energy Economics and Financial Analysis