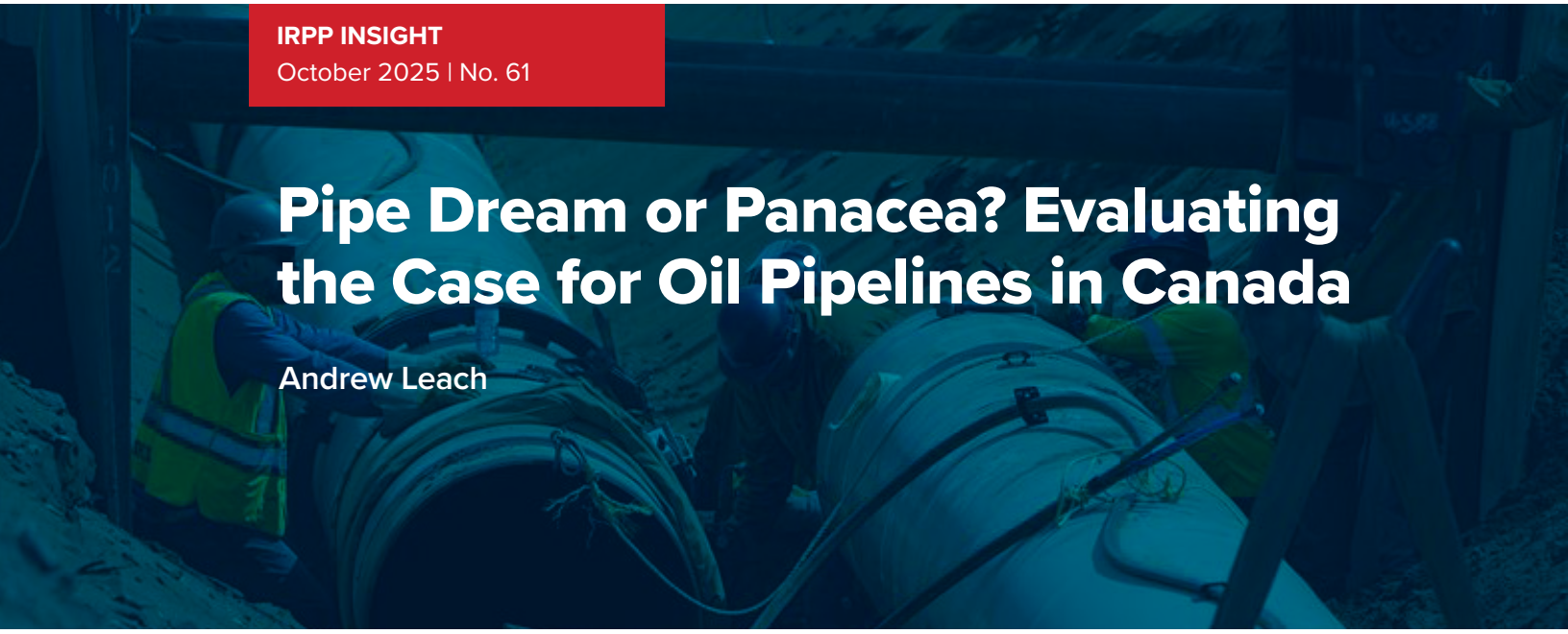
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Pipe Dream or Panacea? Evaluating the Case for Oil Pipelines in Canada

Andrew Leach

IN BRIEF

Some argue that building another oil pipeline in Canada is a pipe dream, with no company willing to step forward as a proponent. Others describe it as a panacea, claiming it will help boost Canada's resilience in the face of U.S. tariffs, create jobs, accelerate economic growth and secure national unity. As with most debates, the evidence suggests more nuance. A new pipeline built to the West could raise the value of Canadian oil, which is something Canadian businesses and workers would welcome in the face of ongoing trade tensions with the United States. However, with projected declines in global oil prices, there is a risk that a new pipeline will affect the viability of existing pipelines and raise costs for oil shippers. This paper provides a clear-eyed assessment of pipeline prospects in Canada and argues that a decision on a new pipeline cannot be left to markets alone.

EN BREF

Certains affirment que la construction d'un autre pipeline au Canada est un rêve irréalisable, aucune entreprise n'étant disposée à se porter promotrice du projet. D'autres décrivent un tel projet comme une panacée, affirmant qu'il contribuera à renforcer la résilience du Canada face aux droits de douane américains, à créer des emplois, à accélérer la croissance économique et à garantir l'unité nationale. Comme dans la plupart des débats, les faits suggèrent une réalité plus nuancée. La construction d'un nouveau pipeline vers l'ouest pourrait augmenter la valeur du pétrole canadien, ce qui serait bien accueilli par les entreprises et les travailleurs du pays dans le contexte des tensions commerciales actuelles avec les États-Unis. Cependant, compte tenu de la baisse prévue des prix mondiaux du pétrole, un nouveau pipeline risque de compromettre la viabilité de ceux qui existent déjà et d'augmenter les coûts pour les transporteurs de pétrole. La présente étude fournit une évaluation lucide des perspectives de construction de pipeline au Canada et soutient que la décision d'en construire un nouveau ne peut être laissée aux seuls marchés.

THE COMMUNITY
TRANSFORMATIONS PROJECT

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HIGHLIGHTS

Oil pipelines are once again a hot topic of discussion everywhere, from political panels to kitchen tables. As Canada navigates a fraught relationship with its largest trading partner, and the economic uncertainty that brings, many see oil pipelines as a panacea. Indeed, memories of the oil booms of past decades — and the economic largesse they brought — are fresh for workers and businesses, as well as for the communities that benefited. With Canadians now fearful of the consequences of trade tensions, it is no surprise that there is substantial interest in tried-and-true economic solutions.

The federal government's new *Building Canada Act* and Alberta's commitment to a West Coast pipeline may create the right conditions for new oil infrastructure. But the devil is in the details. Oil market dynamics have significantly changed in the past two decades, and the future trajectory of global oil prices is uncertain. Add to that the challenge of securing Indigenous support along a prospective pipeline route, and the business case for a new oil pipeline becomes complicated.

In this paper, I assess the viability of a new oil pipeline and make the following observations:

1. **There is a case to be made for another Canadian oil pipeline to the West to access Asian markets.**
   - The United States — Canada's key crude oil customer — has increased its oil production, contributing to an oversupplied market in regions served by our oil pipelines.
   - U.S. refiners used to pay a premium for Canadian crude, which drove the construction of much of our existing pipeline infrastructure to the south. Today, Alberta is selling into a market flush with supply. Alberta oil sells at a discount because of its crude quality and distance from new markets.
   - Canada's current pipelines are close to full. A lack of pipeline capacity could reduce oil value and limit oil production in the future, as shipping by rail is too costly in a world of lower oil prices.
   - A new pipeline to the West would help Canadian oil sell at closer to global prices, reducing discounts. Alternative pipelines such as the Keystone XL (KXL) pipeline to the United States might be quicker and cheaper to build, but would involve longer distances to final markets, increasing costs.

2. **There is a risk that a new pipeline could lead to worse conditions for Canada's oil sector.**
   - An overbuilt pipeline network can erode the value of Canada's oil resource and decrease the viability of existing pipelines such as the Enbridge Mainline from Alberta to the U.S. Midwest and Ontario. If pipelines are underutilized, tolls rise and costs increase for oil shippers, which could eventually risk the viability of the pipeline.
   - While forecasts for global oil consumption have increased over the past few years, this is primarily due to more readily available supply at lower prices. Lower oil prices will reduce the attractiveness of investment in new oilsands production.

- If increased oil production does not materialize after the pipeline is built, the risks of excess pipeline capacity and higher shipping costs rise.

3. **It is getting harder for the federal government to force a pipeline through Indigenous territory.**
   - Recent court rulings show that the government needs to make a serious effort to fulfil its duty to consult Indigenous communities. Expectations are pushing closer to requiring consent from substantially affected First Nations.

For these reasons, a decision on a new oil pipeline should not be left solely to the market. Only governments can determine whether a pipeline is in the overall public interest. In hindsight, the federal decision to build the TMX pipeline was the right call, even given its high cost. But it is not clear that another pipeline will offer the same benefits, particularly when the full slate of risks and rewards is considered.

It is not possible to predict the future with certainty, but Canadians deserve a clear and transparent assessment of the potential risks and rewards associated with a new oil pipeline.

FAITS SAILLANTS

Les pipelines font à nouveau l'objet de vifs débats, des tables rondes politiques aux discussions de cuisine. Alors que le Canada traverse une période difficile dans ses relations avec son principal partenaire commercial, avec l'incertitude économique que cela entraîne, beaucoup voient les pipelines comme une panacée. En effet, le souvenir des booms pétroliers des dernières décennies — et des retombées économiques qu'ils ont générées — est encore frais dans l'esprit des travailleurs et des entreprises, ainsi que dans celui des communautés qui en ont bénéficié. Les Canadiens craignant désormais les conséquences des tensions commerciales, il n'est pas surprenant qu'ils s'intéressent de près aux solutions économiques qui ont fait leurs preuves.

La nouvelle *Loi visant à bâtir le Canada* du gouvernement fédéral et l'engagement de l'Alberta envers la construction d'un pipeline vers la côte ouest pourraient créer les conditions propices à la mise en place d'une nouvelle infrastructure pétrolière. Mais le diable est dans les détails. La dynamique du marché pétrolier a considérablement changé au cours des deux dernières décennies, et l'évolution future des prix mondiaux du pétrole est incertaine. Ajoutez à cela le défi de s'assurer le soutien des populations autochtones le long du tracé prévu de l'oléoduc, et le dossier commercial en faveur de ce nouveau projet devient compliqué.

Cette étude évalue la viabilité d'un nouveau pipeline et formule les observations suivantes :

1. **Des raisons existent en faveur d'un autre pipeline vers l'ouest afin d'accéder aux marchés asiatiques.**
   - Les États-Unis, principal client du Canada pour le pétrole brut, ont augmenté leur production pétrolière, contribuant ainsi à un excédent de l'offre dans les régions desservies par nos oléoducs.
   - Les raffineurs américains payaient autrefois un supplément pour le pétrole brut canadien, ce qui a favorisé la construction d'une grande partie de nos oléoducs existants vers le sud. Aujourd'hui, l'Alberta vend ses produits sur un marché saturé. Le pétrole de l'Alberta se vend à prix réduit en raison de la qualité de son brut et de son éloignement des nouveaux marchés.
   - Les pipelines actuels du Canada sont presque saturés. Un manque de capacité pourrait réduire la valeur du pétrole et limiter la production pétrolière à l'avenir, car le transport ferroviaire est trop coûteux dans un contexte de baisse des prix du pétrole.
   - Un nouveau pipeline vers l'ouest permettrait de vendre le pétrole canadien à des prix plus proches des prix mondiaux, réduisant ainsi les remises. D'autres pipelines, tels que l'oléoduc Keystone XL vers les États-Unis, pourraient être plus rapides et moins coûteux à construire, mais impliqueraient des distances plus longues vers les marchés cibles, ce qui augmenterait les coûts.

2. **Un nouveau pipeline risque d'aggraver la situation du secteur pétrolier et gazier canadien.**
   - Un réseau de pipelines trop développé peut éroder la valeur des ressources pétrolières et gazières du Canada et réduire la viabilité des pipelines existants, comme le pipeline principal d'Enbridge qui relie l'Alberta au Midwest américain et à l'Ontario. Si les pipelines sont sous-utilisés, les droits de passage augmentent et les coûts pour les transporteurs de pétrole s'accroissent, ce qui pourrait à terme compromettre la viabilité du pipeline.
   - Si les prévisions relatives à la consommation mondiale de pétrole ont augmenté au cours des dernières années, cela s'explique principalement par une offre plus facilement accessible à des prix plus bas. La baisse des prix du pétrole réduira l'attrait des investissements dans la production de nouveaux sables bitumineux.
   - Si l'augmentation de la production pétrolière ne se concrétise pas après la construction de l'oléoduc, les risques liés à une capacité excédentaire et à une hausse des coûts de transport augmentent.

3. **Il devient de plus en plus difficile pour le gouvernement fédéral d'imposer la construction d'un pipeline sur les territoires autochtones.**
   - Les décisions judiciaires récentes montrent que le gouvernement doit faire un effort sérieux pour remplir son obligation de consulter les communautés autochtones. Les attentes tendent de plus en plus vers l'exigence du consentement des Premières Nations touchées de manière substantielle.

Pour ces raisons, la décision relative à la construction d'un nouvel oléoduc ne devrait pas être laissée uniquement au marché. Seuls les gouvernements peuvent déterminer si un pipeline sert l'intérêt public. Rétrospectivement, la décision fédérale de construire le projet d'agrandissement du réseau de Trans Mountain était la bonne, même compte tenu de son coût élevé. Mais il n'est pas certain qu'un autre pipeline offrira les mêmes avantages, en particulier si l'on tient compte de l'ensemble des risques et des avantages.

Il est impossible de prédire l'avenir avec certitude, mais les Canadiens méritent une évaluation claire et transparente des risques et des avantages potentiels associés à un nouveau pipeline.

INTRODUCTION

The summer and fall of 2025 have been dominated by talk of oil and gas pipelines. Prospects for a new bitumen pipeline have been spurred by the *Building Canada Act* (*BCA*) — a signature piece of legislation from Prime Minister Mark Carney's government — and its promise to expedite reviews of projects of national interest (PONIs). The Government of Alberta (2025a) committed to act as a proponent for a new pipeline to the northwest coast of British Columbia, in collaboration with three major pipeline companies. It has been pushing for pipelines in all directions to serve potential expanded production from Alberta's oilsands and ward off the impacts of the U.S. trade war (Fedor, 2025). Amid U.S. President Donald Trump's trade wars and threats of annexation, others have cited market diversification and energy security advantages of expanded pipeline capacity (Harapyn, 2025). And, somewhat surprisingly, in an October visit to the White House, Prime Minister Carney joined President Trump in contemplating a revival of the thrice-cancelled Keystone XL pipeline (Yousif, 2025). Not since the pipeline wars of the early 2010s (Hoberg, 2019) has there been such a focus on what projects might get built, to where, and what the impacts might be on Canadian oilsands production.

However, changing patterns in North American and global crude oil markets pose significant challenges. Most importantly, U.S. production has increased from five million barrels per day in 2005 to over 13 million barrels per day in 2025, with much of that new production coming at relatively low cost. This rapid increase in oil supply contributed to a prolonged and unexpected depression in global oil prices, stretching, arguably, from 2015 through to today. This increase has also fundamentally altered regional crude oil markets.

In North America, the change in oil markets has been — if you'll pardon the pun — earth-shattering. Regions that have historically been short on oil, like the U.S. Midwest, are now oversupplied and acting as sources of oil for other markets. The U.S. Gulf Coast, long an oil importer, has become a major exporter of crude oil. These changes have seen the relationship between West Texas Intermediate (WTI) and other global benchmark crudes invert from a premium to a discount. The changes in regional and global oil markets brought on by increased U.S. oil supply, now almost 20 years on, continue to create a near-perfect storm for Alberta's oilsands.

Alberta's massive oil resources are stuck at the northern end of the North American pipeline network. For decades, Alberta benefited from easy access to U.S. and Canadian markets in the mid-continent willing to pay a premium for oil. Many refineries in those regions undertook major investments to process the heavier crude, which was now flowing in increasing quantities from Alberta's oilsands projects. Now those refineries benefit from a market oversupplied with crude. As such, Alberta, relatively isolated from other markets and facing delays in the construction of new pipelines, has seen periods in which its products face large discounts compared to global prices. These discounts, combined with the overall reduction in long-term oil price expectations, create an uncertain economic future in the province. And, while it's true that global oil forecasts see much higher demand than was the case a decade ago, that's not good news for higher-cost resources like Alberta's. On the contrary, these forecasts are a consequence of the relative availability of cheaper, easier oil. And that's a problem new pipelines can't solve.

This is not to say that pipelines don't matter — they absolutely do. New pipelines just won't usher in a return to the boom times of previous decades because things have changed. North America and the world no longer need Alberta's oil in the same way they did when major global oil players sought a foothold in the oilsands 10 to 20 years ago. However, unlike in previous booms, proponents can no longer credibly argue that Alberta's oil could get to market by other means if pipelines were not built. Due to the present pricing environment, production will almost certainly be limited by a lack of pipeline capacity to high-value markets.

This paper argues that, while pipelines remain important to the viability of the Canadian oilsands, North American and global crude oil markets have changed in ways that dramatically reduce the potential value available. First, I ask why Canada has historically chosen to ship its oil to the United States rather than to *tidewater* markets. I then show how production changes in both Canada and the United States have shifted crude movements in North America, and discuss how these altered flows have increased discounts for Canadian oil exports. Next, I assess the state of our current pipeline infrastructure. Finally, I consider the potential for new pipeline construction in Canada, including a sketch of the potential timelines and regulatory challenges involved.

WHY DOES CANADA SHIP OIL TO THE UNITED STATES?

Crude supply in Western Canada has exceeded domestic demand for decades, and pipeline and rail capacity expanded over time to export excess crude oil. With production continuing to grow and existing infrastructure near capacity, calls for new pipeline construction have returned in earnest. In the last decade, we've also seen a major shift in the desired direction of a new pipeline, with Canada's West Coast becoming the destination of choice. Another pipeline to the United States has become, for multiple reasons, much less desirable.

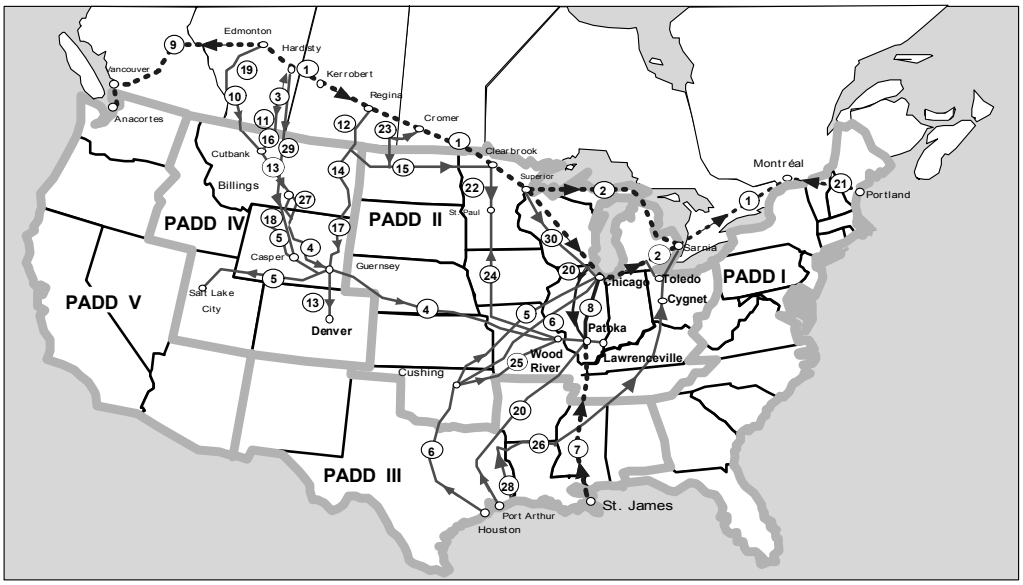
Among these calls for new pipelines west lies an unspoken suggestion that decisions to build Canada's extant pipeline network to serve U.S. Midwest and Gulf Coast markets may have been a strategic error. While that may be true in hindsight, in the moment it was a strategic decision to serve the world's largest crude oil importer — and one made in concert with U.S. public investments to refit the American domestic refinery fleet to process more oilsands bitumen (Canadian Association of Petroleum Producers [CAPP], 2007; National Energy Board [NEB], 2005). Recall that, as part of the *Energy Policy Act of 2005*, the United States allowed for accelerated capital cost allowances for refinery investments that increased oilsands processing capability by at least 25 per cent. Our ease of access to American markets and their consequent view of oilsands as a strategic fuel for their economy provided a substantial boost to the value of our oil resources.

Historically, Canadian crude exports served refineries in the U.S. mid-continent, from the western plains, south and east to the Great Lakes region. What Canada could not supply was made up for with movements north from the Gulf Coast. Pipeline infrastructure in North America around the turn of the millennium, shown in figure 1, was built to accommodate these market dynamics. Importantly, pipelines were not built with the intention of selling

to the United States at discounted prices. On the contrary, they were constructed with an expectation of selling our resources to the Americans at a premium to comparable, quality-adjusted global prices.

When shown on a map (figure 1), pipelines indicate pricing relationships: they move oil to regions with higher prices on offer than those that would be obtained at their origin. Before the fracking boom in the United States, the Midwest was short on crude oil. Consequently, refiners in that area paid a premium large enough to make it worthwhile to ship crude north from the Gulf Coast and south from Canada. This meant a quality-adjusted price in the U.S. Midwest above global prices — a premium Canadian firms could take advantage of. We saw Alberta light oil trade at comparable or even premium prices to WTI and Brent (Sproule, 2025). However, even then, heavier and higher-sulphur oil traded at a discount to light oil due to its lower crude quality.

Figure 1. Crude oil pipelines and direction of flow in 1997



1. Interprovincial Pipe Line Inc.
2. Lakehead Pipe Line Co. LP9
3. Bow River Pipeline
4. Platte Pipeline Co.
5. Amoco Pipeline Co.
6. ARCO Pipeline Co.
7. Shell Pipeline Corp. (Capline)
8. Chicago Pipeline Co. (Chicap)
9. Trans Mountain Pipe Line Co.
10. Rangeland Pipe Line Co.
11. Murphy Oil Co. (Milk River)
12. Wascana Pipe Line Co.
13. Conoco Inc.
14. Texaco Pipe Line Ltd.
15. Portal Pipe Line Co.
16. Cenex
17. Butte Pipeline
18. Exxon Pipeline
19. Imperial Pipe Line Co.
20. Mobil Pipe Line Co.
21. Portland Pipe Line
22. Minnesota Pipe Line Co.
23. Westspur Pipe Line
24. Koch Pipelines Inc.
25. Shell Pipeline Inc.
26. Midvalley Pipe Line
27. Amoco/Conoco Pipeline
28. Sun Pipeline
29. Express Pipeline Ltd.
30. Proposed Lakehead Line 14

Source: Reproduced from National Energy Board (NEB) Decision OH-2-97, Interprovincial Pipeline.

These mid-continent premium prices were behind the decision to reverse Enbridge's Line 9 between Montreal and Sarnia (NEB Decision OH-2-97) to bring crude oil from Montreal to Sarnia. For the first decade of the new millennium, further expansion into the Great Lakes region was the order of the day for Canada. Construction of the Keystone pipeline (Canadian approval OC-51 issued in 2008) and the Alberta Clipper project, which expanded the Enbridge Mainline system (Canadian approval OC-54 issued in 2008) to serve areas north of Cushing, Oklahoma, sought to capture the premium prices offered in those markets.

Today, it is taken for granted that Canada sells crude to the United States at a discount — a pricing relationship that is discussed as a failing of Canadian business or political savvy. However, the most-discussed Canadian crude discount — that of Western Canadian Select (WCS) — is a combination of two separate effects: a location discount and a crude quality discount.

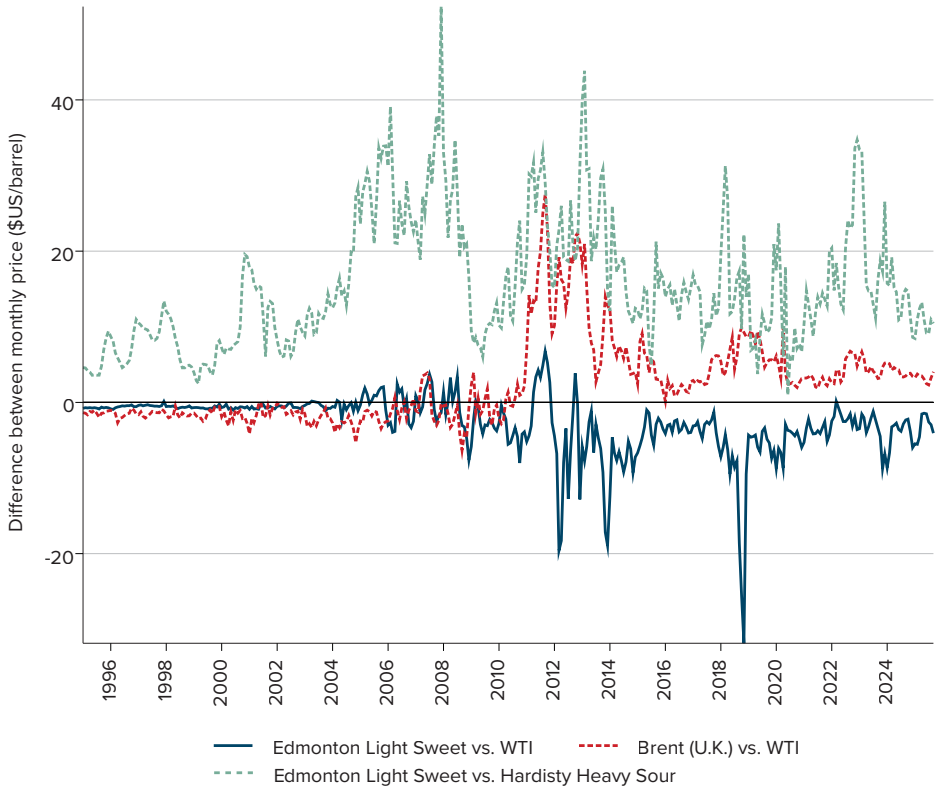
The WCS price reflects the value of heavy, sour crude delivered to Hardisty, Alberta. "Heavy" crudes are denser than "light" crudes, and "sour" crudes have more sulphur than "sweet" crudes.

This price is generally compared to that for WTI, a light, sweet crude blend, delivered to Cushing, Oklahoma. Heavy, sour crude almost always trades at a discount to light, sweet crude because it is more expensive to process and yields a lower-value slate of products once refined (Sproule, 2025).

Figure 2 shows that heavy, sour crude is consistently valued at a discount to light, sweet crude in Alberta.

As of this writing, WCS crude is trading at a US$7.25-per-barrel discount to WTI, when both are valued at Cushing (CME Group, 2025). This is the quality differential between

Figure 2. Pricing relationships between types of crude oil



Source: Author's graphic based on Sproule (2025).
Note: Chart shows pricing relationships between Brent (U.K.), West Texas Intermediate (WTI) (Cushing, Okla.), Edmonton light, sweet crude oil, and Hardisty, Alta., heavy, sour crude oil. Edmonton Light series is constructed from Edmonton Par prices through April 2014, and Canadian Light Sweet from that point forward.

two crude oil blends priced at the same location. The same WCS crude blend, priced in Hardisty, reflects a larger discount of roughly US$11 per barrel to WTI at Cushing at the time of writing, reflecting transportation costs between Hardisty and Cushing and the quality differential combined (Oil Sands Magazine, 2018).

Quality differentials won't generally be affected by additional pipeline capacity. However, sufficient capacity ensures the discount on Canadian crudes reflects the lowest possible transportation costs, all else equal.

When pipelines serve markets in which higher prices are generally obtainable, they can increase the value of crude oil in Canada. Unfortunately, the markets served by most of our pipeline capacity have seen prices decline substantially relative to global benchmarks over the last two decades. As recently as the lead-up to the 2008 financial crisis, light crude prices at Edmonton traded at above par with WTI, which in turn traded at a premium to Brent (figure 2). Since 2010, this relationship has reversed, with WTI now trading at a discount to Brent and Edmonton light oil trading at a discount to WTI.

What changed? The answer lies in the direction of crude oil flows and regional oil market dynamics. As described in the next section, the fracking boom, which took hold in the wake of the 2008 financial crisis, combined with continued increases in oilsands production, oversupplied the North American market. This excess has been particularly acute in the Midwest and the Gulf Coast, the primary destinations for Alberta crude exports.

The markets we built our pipelines to serve are now producing more crude than ever themselves. This shift forces Canadians to ask a question that would have been heretical more than a decade ago: Does the United States still need Canadian oil? The answer is yes, to a degree, but we can no longer realize a premium price for our exports.

DOES THE UNITED STATES STILL NEED CANADIAN OIL?

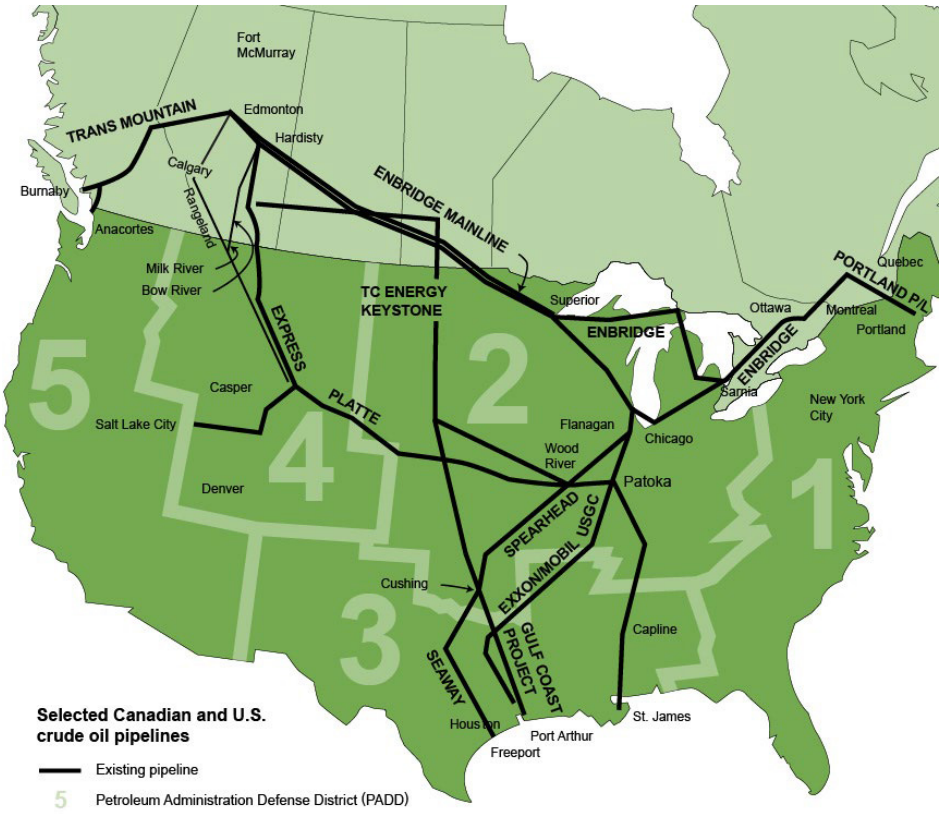
Since 2008, North American oil and gas companies have been exploiting the combined innovations of horizontal drilling and hydraulic fracturing ("*fracking*") to extract long-known hydrocarbon deposits called *tight* or *shale* oil. Today, tight oil production has reached over nine million barrels per day, accounting for much of the 13 million-barrel-per-day growth in U.S. production since the 2008 financial crisis.

U.S. production growth has been concentrated in the Midwest, Rocky Mountain and Gulf Coast regions, while production has declined on the U.S. East and West Coasts. Canadian production has also grown by over 2.5 million barrels per day over the same period, with almost all growth coming from increased production from Alberta's oilsands. Mexico, another important supplier into the North American market, has seen oil production drop to 1.8 million barrels per day from a peak of 3.5 million barrels per day in 2003 (U.S. Energy Information Administration [EIA], 2023). Overall, North America is producing almost 10 million barrels per day more oil than was the case two decades ago.

At the same time, U.S. net crude oil imports have declined from a peak of 10 million barrels per day to less than 2.5 million barrels per day today. The market for Alberta's crude oil has changed dramatically.

The changes for Alberta are amplified because growth in both U.S. and Canadian production occurred in the primary regions served by Canada's oil pipeline infrastructure (figure 3). The Canadian prairies and the U.S. mid-continent have seen a roughly 11-million-barrel-per-day increase in production rates since the 2008 financial crisis (figure 4). Prior to this change, as discussed above, crude oil flowed north and south into the premium market around the Great Lakes. Today, the United States Midwest and Gulf Coast are oversupplied with crude oil, which is depressing prices in those markets.

Figure 3. Canadian export pipeline infrastructure and U.S. Petroleum Administration Districts for Defense (PADDs)

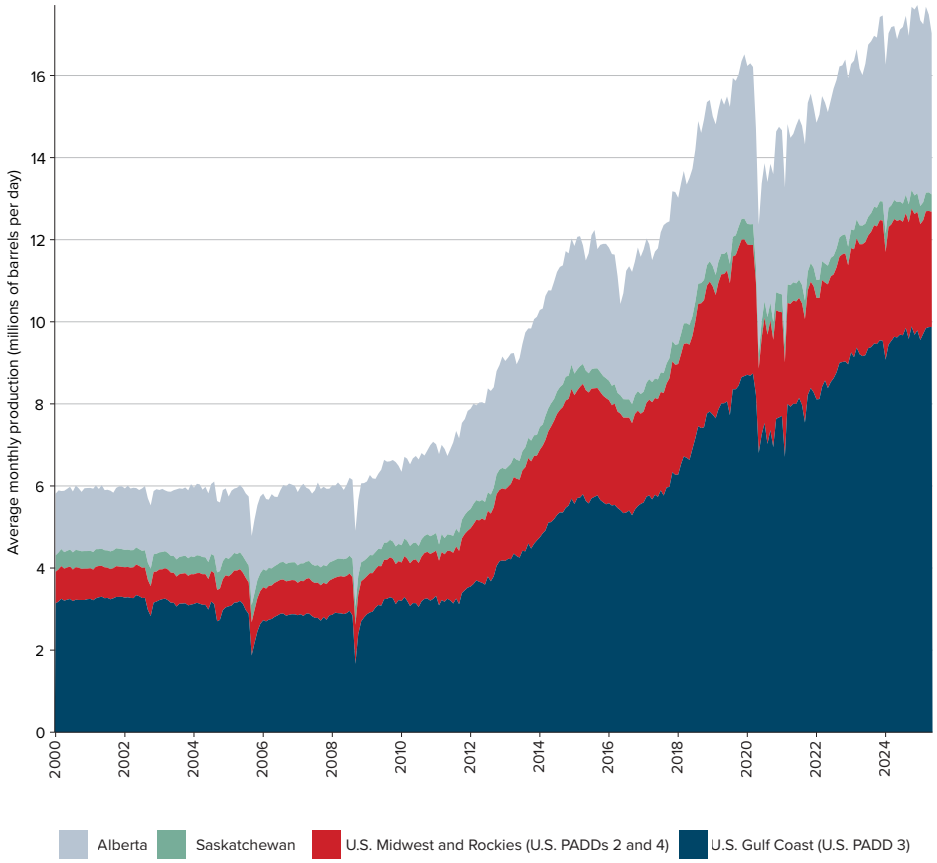


Source: Reproduced from Alberta Energy Regulator (AER, 2025).

As U.S. crude oil production grew alongside increasing Canadian pipeline exports, flows changed. We've seen new pipelines built and others reversed throughout the mid-continent to move crude oil to the Gulf Coast. New export terminals have been built on the Gulf Coast as well, once the United States lifted its 40-year-old ban on such exports in 2015.

With the coincident decline in Mexican and Venezuelan production and the rise in oilsands production, more Canadian crude has made its way to the Gulf Coast, via both the Keystone and Enbridge pipeline systems, which have extended to move Canadian imports further

Figure 4. Canadian and U.S. crude oil production by region



Source: Author's graphic based on U.S. Energy Information Administration (EIA) and Canada Energy Regulator (CER, 2025a).

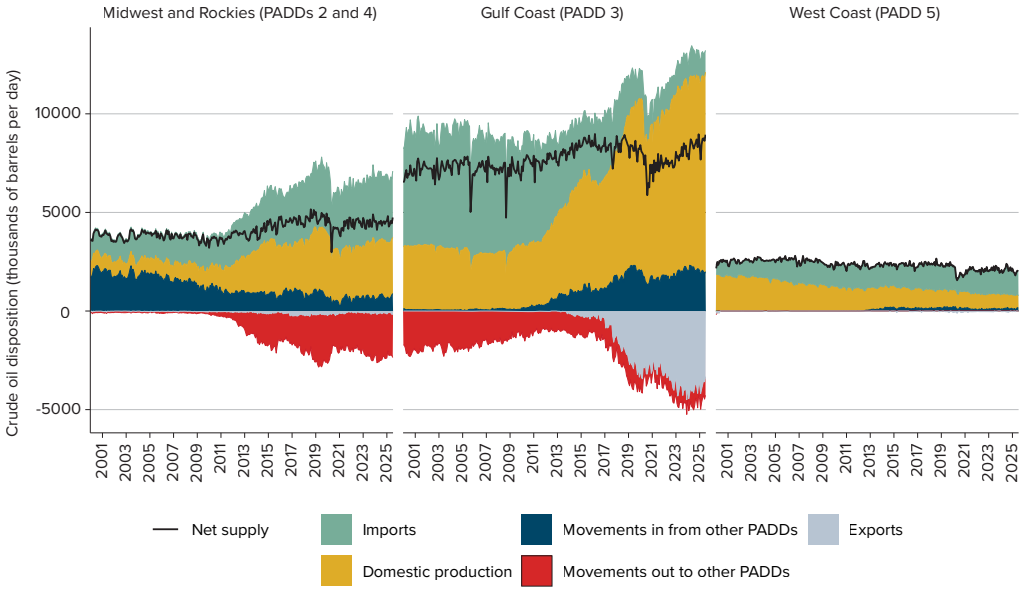
south. We've also seen more Western Canadian crude oil reaching markets in Ontario and Quebec, via reconfiguration and expansions of the Enbridge pipeline system, including Line 9 through Ontario. The bottom line: Our oil is moving a lot further through pipelines than expected two decades ago, and it's making up for distance with discounts.

While the United States remains a net crude importer, Canadian oil is moving further and competing with American production, not only in domestic markets, but in export markets as well. In hindsight, some new pipeline capacity beyond the Trans Mountain Expansion might best have been built to the west coast rather than the U.S. Midwest. We may soon say the same of infrastructure serving the U.S. Gulf Coast.

The U.S. Midwest, Rockies and Gulf Coast regions still import some crude oil (figure 5). However, since 2008, oil production in the Midwest and Gulf Coast has grown, supplying more of those regions' needs.

In the Midwest, we see a rapid reversal of crude oil movements — instead of receiving oil from the Gulf Coast, the Midwest is now a net supplier of crude to that region. Because

Figure 5. Crude oil production and disposition by relevant PADD regions



Source: Author's graphic based on U.S. Energy Information Administration (EIA).
Note: PADD stands for Petroleum Administration District for Defense. Not shown here are crude re-exports or volumes transshipped to Canadian destinations on the Enbridge system through the United States.

most Canadian pipelines also flow into the Midwest, it quickly became oversupplied. This excess led to large discounts in crude oil prices relative to global benchmarks, until new or modified infrastructure allowed shipments to the Gulf Coast. This was not the crude oil market that Canadian regulators or producers expected, and our infrastructure was not built to maximize the value of Canadian crude under these conditions.

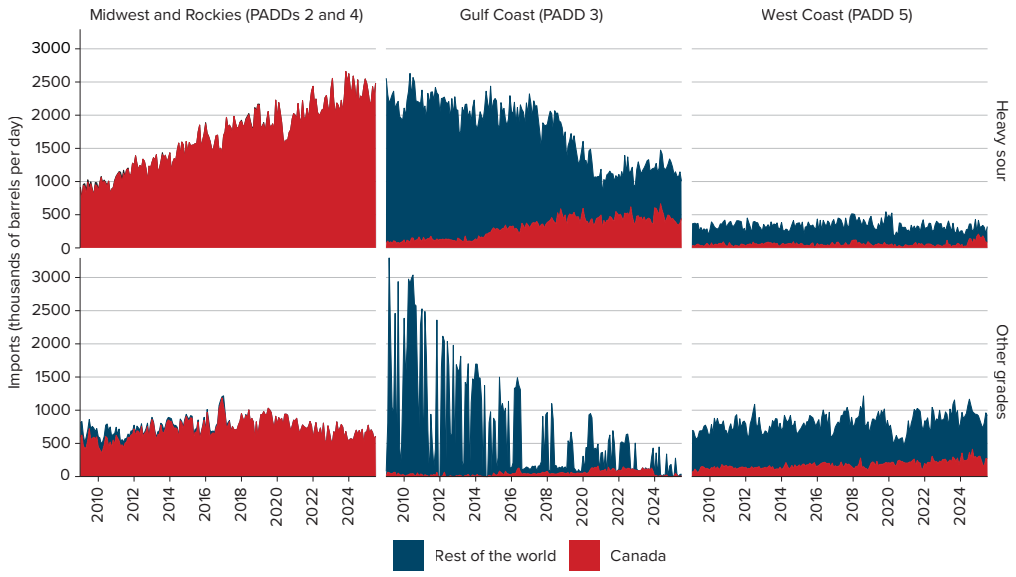
The Gulf Coast has also seen a large reversal in flow since 2008, with crude oil exports replacing what were, traditionally, large movements into the mid-continent. Domestic production and movements in from the Midwest and Rockies continue to crowd out imports and have allowed for surging exports of crude oil.

The U.S. West Coast increasingly relies on imports, though it is a much smaller market than the Midwest or Gulf Coast. The East Coast (PADD 1, not shown) is almost entirely import-dependent, but is an even smaller market.

Canadian crude accounts for all imported oil refined in the U.S. Midwest and Rocky Mountain regions and roughly one-third of that refined on the Gulf Coast (figure 6). Declining imports of heavy, sour crude refined on the Gulf Coast are the most relevant recent change for Canadian oilsands production, although falling total imports refined in the U.S. Midwest and Rocky Mountain regions are also notable.

Less than a decade ago, the Gulf Coast market for heavy, sour crude oil was one where Canada could envision displacing roughly two million barrels per day of imported oil from other sources. While Canadian imports to the region have increased, the total contestable

Figure 6. U.S. crude oil imports, by region (columns) and crude grade (rows), from Canada and other countries



Source: Author's graphic based on U.S. Energy Information Administration (EIA) data.
Note: PADD stands for Petroleum Administration District for Defense.

market for imports has declined by over a million barrels per day in a decade. In fact, the market for Canadian crude oil on the U.S. Gulf Coast may already have reached its limit. A recent piece by Rory Johnston (2025a) shows how, prior to the opening of the Trans Mountain Expansion Project (TMX), Canadian barrels were flowing in increasing volumes south to the Gulf Coast for re-export. Johnston uses shipping data to show that re-exports of Canadian crude from the Gulf Coast reached nearly half a million barrels per day by early 2024. However, once TMX entered service, Gulf Coast re-exports dropped to roughly 100,000 barrels per day.

The Gulf Coast market may be nearing saturation with Canadian crude — a fact that should alarm Canadian producers. Even if a pipeline project like Keystone XL were to re-emerge, this saturation suggests it would act mostly as a re-export line rather than serving United States refineries. This shift implies that even larger transportation discounts would apply to Canadian crude oil. Shipping crude oil to the Gulf Coast for re-export is a longer and potentially costlier route than going west.

It's not just the United States that has seen changes in crude oil flows. Enbridge's Line 9 in Ontario and Quebec is a bellwether for changing crude oil flows and values in North America.

Line 9 was initially built to serve Montreal with crude from Western Canada, as it does today. Brought into service in 1976 in the wake of the OPEC crisis, the pipeline operated west-to-east for 23 years. In 1999, the line was reversed to bring crude oil from Montreal to

Sarnia, based on the argument that Ontario refiners were at a disadvantage in the market compared to coastal refiners and those in the Chicago area because of the competition for crude oil. At that point, the expectation was that Brent crude oil, which landed at Sarnia via pipeline, would be cost-competitive with Western Canadian crudes (NEB Decision OH-2-97). Yes, you read that correctly: tidewater oil was *cheap*, not the other way around.

But that all changed in less than a decade. In 2012, the western segment of the pipeline was reversed to bring crude oil from Sarnia to Westover, Ontario. This change allowed refineries to capitalize on the decreased prices for Western Canadian crude resulting from increased U.S. production (NEB Decision OH-005-2011). In 2014, the NEB approved the reversal of the balance of Line 9 (NEB Decision OH-002-2013). This approval cited predictions that Montreal refineries might save up to $8.88 per barrel on the cost of crude oil in 2024 by procuring it from Western Canada instead of importing it at global prices. Tidewater oil was cheap no longer — Alberta's crude was.

While pipeline reversals and reconfigurations allowed refiners on the Gulf Coast and in Ontario and Quebec to benefit from discounted oil from Western Canada, they have disadvantaged Western Canadian producers. As mid-continent crude oil pricing has become discounted relative to global crudes, Western Canadian crudes reflect even larger discounts to global prices because our prices factor in higher transportation costs to reach the marginal market for our oil.

In such an environment, a pipeline following the shortest route to *tidewater* — rather than serving oversupplied inland markets — could significantly raise the value of produced oil. But that would only be true if new pipelines are full. If not, there is a risk that an underutilized network results in higher transportation costs, stranded pipeline assets or both.

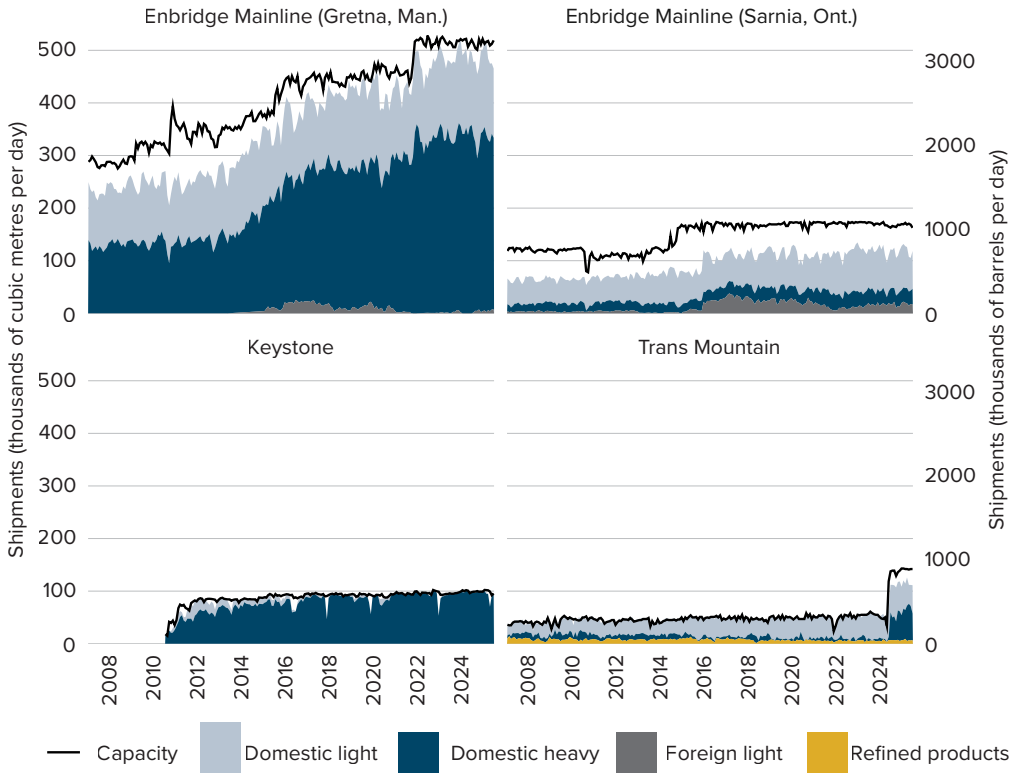
DOES CANADA NEED MORE PIPELINE CAPACITY?

The capacity of existing pipelines out of Western Canada may be insufficient to meet current and future export demand, although whether that means another pipeline would be in the national interest is a separate question.

It is possible that incremental expansions of the current network will be sufficient, especially given a looming period of forecast low oil prices. Alternatively, a single new pipeline may find sufficient shipper support that allows it to be built without compromising the viability of existing pipelines. It's challenging to find supporting evidence for more capacity than, at most, what a single new line would provide. And even with the legislative changes brought forward by the Carney government, building a new pipeline may still prove a long and challenging process.

Are current pipelines full? Not yet, but they're close to capacity. The system will likely soon be too congested to maximize the value of Canadian production. No single data point indicates whether our existing pipeline infrastructure is functionally *full*, although we can point to many indicators, including physical and economic measures.

Figure 7. Utilization of major Canadian export pipelines



Source: Author's graphic based on Canada Energy Regulator (2025b).

The most obvious indicator is capacity utilization on existing pipelines. Our major export pipelines are nearly full, although we're not quite at a crisis point (figure 7). Capacity on Canada's existing major pipeline network is 5.25 million barrels per day (CER, 2023) with some month-to-month variability. This total includes TMX and the refurbishment of Line 3 on the Enbridge Canadian Mainline system. Figure 7 shows the capacity of the Enbridge Canadian Mainline, both at the U.S. border at Gretna, Manitoba, and back into Canada via Sarnia. Through Sarnia, the Mainline serves refineries in southern Ontario and Enbridge's Line 9, which can carry up to 300,000 barrels per day onward to Montreal. Unlike the export lines, the pipeline into Sarnia has significant excess capacity at present.

In the last quarter of 2018, the three major export pipeline systems (TransCanada Keystone, Enbridge Mainline and Trans Mountain) used 98 per cent of their capacity. Consequently, crude production was curtailed in Alberta to try and sustain higher total value for the province's resources (Schaufele & Winter, 2023). This situation has improved with the completed expansions of the Trans Mountain and Enbridge systems, leading to minimal excess capacity today on Trans Mountain and seasonal availability on the Enbridge Mainline.

That said, our major export pipeline system has current capacity utilization rates of well over 90 per cent. January saw peak 2025 export volumes at 5.04 million barrels per day, which amounted to capacity utilization of over 94 per cent after deducting rail volumes

(CER, 2025b). This approaches the point where a pipeline system would be functionally *full*. Another indicator of system constraints is whether pipelines are oversubscribed at particular points, and thus subject to pro-rationing of capacity. This is only an issue for common carrier pipelines, which include the Enbridge Mainline and uncontracted portions of the Keystone and TransMountain systems. In the past year, both Keystone and some parts of the Enbridge Mainline have been fully subscribed, or in some cases, over-subscribed (CER, 2025c).

The current situation, however, contrasts with the recent past. In almost every month from mid-2016 through mid-2024, each of the three main export pipelines had substantial excess demand for their common carrier capacity, which is not generally the case in 2025. However, the fact that periodic oversubscription remains again indicates a pipeline network that is approaching functional capacity.

Another indicator of a pipeline-constrained market is the volume of crude oil shipped by rail. It is generally more expensive to ship crude by rail than by pipeline (Forrest, 2019). If pipeline capacity is available, it is generally the preferred shipping option. Rail is then relegated to niche markets or where it is advantageous to ship crude rapidly, as rail has shorter transit times than pipelines.

Rail shipments of Canadian crude reached record highs in late 2018 and early 2019, coincident with the pipeline constraints that curtailed production in Alberta. However, rail shipments had been rising steadily since pipeline apportionment became more common in mid-2016.

Today, exports of crude oil by rail are at their lowest levels since 2016 (CER, 2025d), outside of the early months of the COVID-19 pandemic — which again indicates a pipeline network that is not physically constrained, even if that might not be far off. Note that, as many shippers built and contracted with rail loading terminals to access rail service in previous periods of pipeline constraints, we would not expect rail use to drop to zero once pipelines are available.

Finally, and perhaps most importantly, we can look at crude oil pricing differentials. Since the opening of the Trans Mountain pipeline, differentials between WCS and WTI have reached some of their lowest values in decades, again supporting the notion of a physically unconstrained network (Johnston, 2025b). Here too, this situation could change quickly if production growth continues and new pipeline capacity is lacking.

Does Canada need a new pipeline?

There are two different reasons to consider a new pipeline: to serve expanded production or to increase domestic energy security and market diversification.

I deal primarily with the first reason in this paper. I ask whether, with expected growth in Canadian oil production, the existing network would again become oversubscribed, leading to some combination of forgone production, unduly discounted barrels, and increased shipment by rail and truck.

However, with our pipeline network largely focused on the oversupplied U.S. mid-continent, and with the increasingly fraught trading relationship between Canada and its southern neighbour, I recognize there may be a willingness to build pipelines elsewhere. These pipelines may aim to access markets such as the Asia-Pacific region or Eastern Canada — despite otherwise sufficient physical capacity — for energy security and market diversification reasons. There is also a nationalist feeling, around since before the National Energy Program of the 1980s, that we should supply our own domestic markets.

Building new pipelines without production growth would involve some combination of compromising existing pipeline assets or operating new assets at well below optimal capacity utilization to provide optionality or an alternative to existing pipelines serving Eastern Canada through the U.S. These raise issues beyond the scope of this work, but this is not to suggest that a decision to build infrastructure for these reasons would be unwarranted. Absent an energy security motivation, Eastern Canada is currently well supplied and at a much greater distance from Alberta than the West Coast of Canada. Building a pipeline east, relative to other options, would entail more transportation costs — and thus Alberta would see greater discounts to world prices.

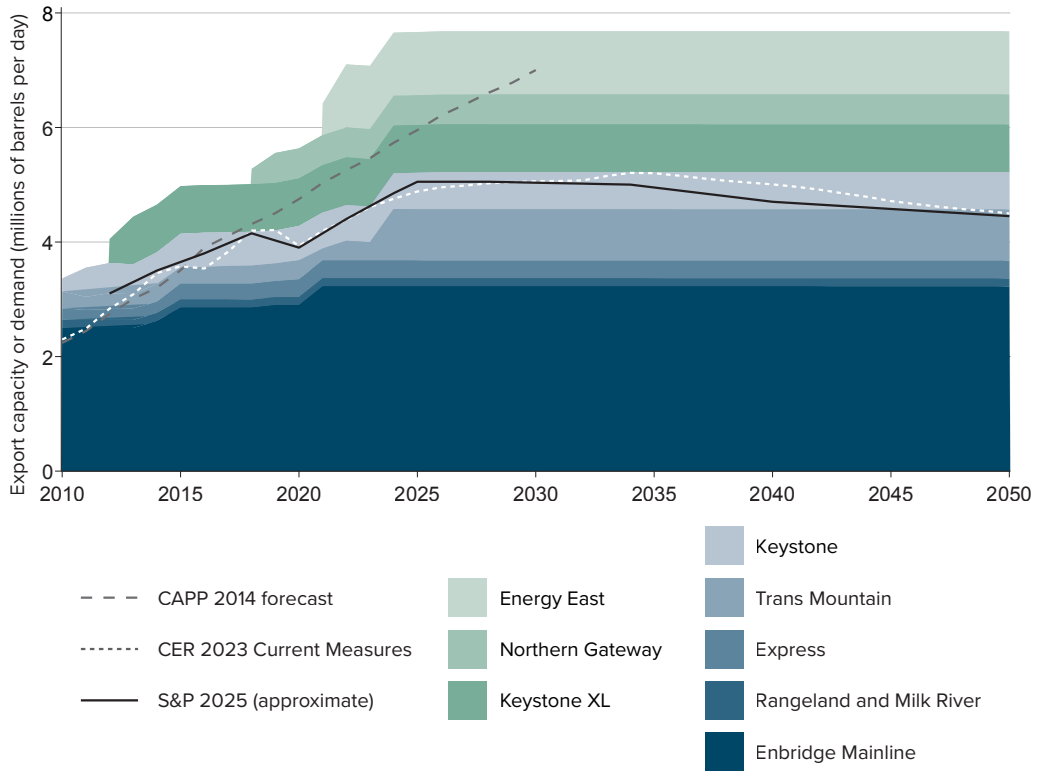
Sufficient pipeline capacity today does not mean an optimal system for the coming years or decades if we expect production and excess supply to grow considerably. However, at least in the recent past, the growth outlook for the oilsands has been insufficient to motivate a material increase in pipeline capacity beyond what can be achieved using existing pipelines.

The Government of Alberta (2025b) speaks confidently about doubling oil production, but that stands in stark contrast to even the most bullish of current industry forecasts. For example, S&P Global (Birn & Hwang, 2025) estimates that oilsands production will peak in 2030 at more than 18 per cent above 2024 levels, adding roughly 600,000 barrels of production per day. While this lies well short of doubling oilsands production, output sustained at those levels beyond 2030 would justify a new pipeline or material expansions of existing pipelines.

The Alberta Energy Regulator (2025) ST-98 forecasts longer-term growth, with oilsands production rising through its 2034 forecast horizon. However, it also forecasts a smaller increase in supply than the S&P estimate, predicting roughly 400,000 barrels per day of new production by 2030. The Canada Energy Regulator's (2023) scenarios, shown in Figure 8, are dated, but show that, even with no new policies to combat climate change, oil supply available for export would peak in 2035 at levels comparable to those in the S&P Global estimate (Birn & Hwang, 2025; Yergin et al., 2025).

With these forecasts in mind, it is hard to conclude that Canada will be short of pipeline capacity by more than what a single new pipeline or expansions of existing capacity would provide. If production does decline after 2035, as predicted by both S&P and the CER, the economics of a new pipeline would be challenged, given that the capital costs of such a project need to be amortized over decades for the shipping tolls charged to be cost-competitive.

Figure 8. Existing Canadian pipeline capacity (blue), proposed pipeline projects (green), and estimated crude oil export demand volumes from S&P Global



Sources: Author's graphic based on Yergin et al. (2025), Canadian Association of Petroleum Producers (2014), and Canada Energy Regulator (2023).
Note: Dotted lines represent estimated crude oil export demand forecasts from the Canadian Association of Petroleum Producers (CAPP), Canada Energy Regulator (CER), and S&P Global (S&P).

The lack of projected oilsands growth is not due to a lack of approved oilsands projects. Alberta currently has over three million barrels per day of oilsands mining and in situ projects holding regulatory approvals, but for which construction has not started or is currently on hold (AER, 2025). The challenge for these projects is the willingness of proponents to invest in long-term oil production in an environment of decreasing oil price outlooks, with any potential transportation disruption amplifying the impact of low prices on investments. As of this writing, oil futures reflect expected prices below US$70 per barrel for Brent crude oil and close to $60 per barrel for WTI over the coming decade (Winston, 2025). The EIA shorter-term forecast calls for WTI prices to fall below $50 per barrel through 2027 (Winston, 2025).

In such a pricing environment, new oilsands mines are a non-starter as such projects can only earn a reasonable rate of return on capital when WTI prices remain closer to US$80 per barrel plus inflation (AER, 2025). Even expansion and production-sustaining projects may be challenged if prices stay in the US$50-per-barrel range for long. New in situ projects carry some risk as well given current price projections, with WTI price expectations likely needing to remain above US$60 per barrel for investors to be comfortable sanctioning new projects. But as Birn and Hwang (2025) and Fellows (2022) point out, the costs of

incremental expansions lie far below these break-even thresholds, as do existing project operating costs. The existing oilsands industry is secure, but prices will determine the need for new transportation infrastructure.

Figure 8 shows the capacity and proposed in-service dates for three previously proposed pipeline projects. These include the 830,000-barrel-per-day Keystone XL pipeline, the 1.1-million-barrel-per-day Energy East project linking Hardisty and the Canadian East Coast port of Saint John, New Brunswick, and the 525,000-barrel-per-day Northern Gateway project from Edmonton, Alberta, to the west coast of Canada at Kitimat, B.C. For context, I also include an older export demand forecast from the Canadian Association of Petroleum Producers (CAPP, 2014), which shows why so many pipeline projects were proposed around that time.

Demand for export capacity has decreased with the decline in global oil prices since 2014, and previously proposed capacity would be excessive in the context of currently expected supply projections. Without prices high enough to spur brownfield and, perhaps, some greenfield expansion in the oilsands, oil export demand is unlikely to exceed the capacity of the existing network by enough to warrant a new pipeline. If prices are high enough to underpin such expansions, we should expect to quickly see high utilization rates, more recourse to rail and higher differentials as we near a pinch-point before 2030.

There is a credible argument that the observed decline in export demand from 2014 through today is a function of the lack of pipeline capacity, not an argument against building that capacity. It is likely that at least some potential production growth has been stifled by concerns over market access. That said, it is useful to recall that, prior to the post-2014 crash, the industry position and the finding of multiple regulatory proceedings (e.g., United States Department of State, 2014) were that the oil would get to market no matter what. The only question was whether that would happen by pipeline or rail.

That question is no longer relevant today. So long as WTI prices remain in the range of US$50 to US$70, the transportation cost advantage provided by pipelines over rail will likely be material. And, even if it only increases prospective revenue by a few dollars per barrel, pipeline access to a higher-value market such as the Pacific Coast will materially raise the prospective returns from new oilsands projects, making those developments more likely. As I discuss below, changes in global oil price outlooks have driven down oilsands growth forecasts much more than a lack of market access. But the current pricing environment is such that any new development is almost surely dependent on new pipelines and vice versa.

Clearly, a single pipeline on the scale of any of the previously proposed projects would be sufficient to avoid a capacity shortfall given current price outlooks and prospective export demand. However, in the years leading up to or following the in-service date of any new pipeline, there is a real possibility that oilsands production, and thus export demand, could wane — something that should give both regulators and proponents pause. If that is true, any new pipeline built in the next five years would increase the probability of stranding other assets in the pipeline network. Utilization rates would quickly become too low, leading to increased tolls that raise shipping costs substantially. An overbuilt pipeline network can erode the value of our oil resources, too.

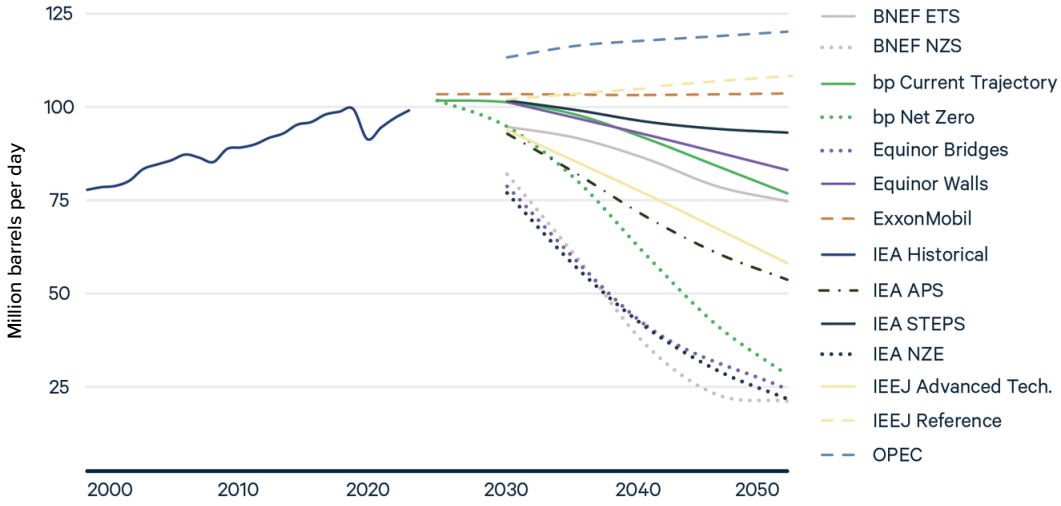
Are there other markets for Alberta oil?

The muted oilsands growth forecasts discussed above stand in stark contrast with increasing forecasts for global oil consumption. Projections of growing global oil consumption are taken by some as a sign that the export demand depicted in the CAPP (2014) forecast in figure 8 would soon return if pipeline capacity were available.

It is true that forecasts of global oil consumption have increased, but that's a symptom of a larger problem — not a cause for celebration — in the oilsands.

Except for the Organization of Petroleum Exporting Countries (OPEC) projection shown in figure 9, most institutional forecasts continue to show modest or negative long-term growth in oil consumption, although in many cases they also show higher long-term consumption than forecast in previous years. OPEC, on the other hand, forecasts substantial growth from current levels — one that represents a significant increase over its recent past forecasts, too. In 2021, OPEC's forecast demand for 2045 was 108 million barrels per day, while this year's outlook places that figure above 120 million barrels per day.

Figure 9. Global crude oil demand forecasts



Source: Reproduced from Resources for the Future Global Energy Outlook (Zhu et al., 2025)
Note: Other than "IEA Historical," all lines represent harmonized global crude oil demand forecasts from 13 different scenarios across seven energy outlooks published in 2024.

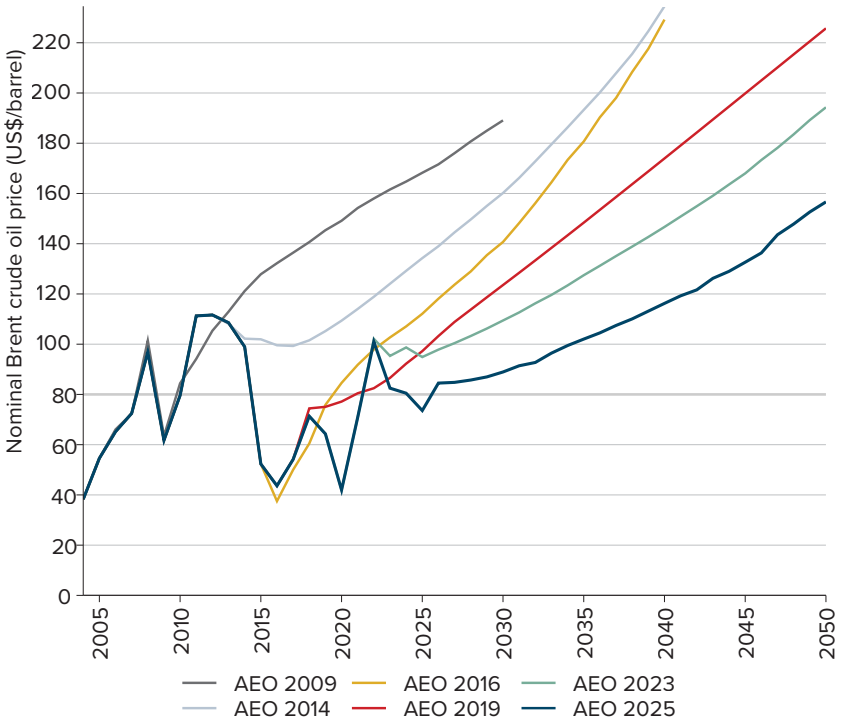
While these forecasts sound like good news for the oilsands, I would argue the opposite. This is because what's underpinning these aggressive consumption forecasts is increased availability of crude oil at lower-than-expected prices. Demand curves, as economists are fond of pointing out, slope downward. Therefore, consumers will use more oil if it is cheaper, all else equal.

Unlike the pre-2008 oil market situation that had Jeff Rubin calling first for $100-per-barrel oil prices (Zehr, 2007) and later for $200 (Rubin, 2012), today's oil forecasts are not symptomatic of a world clamouring for ever-more-expensive oil. Rather, they are a

product of technology and policy enabling ever-cheaper production. Figure 10 shows that leading price projections, such as those from the U.S. EIA, have almost systematically overestimated the future value of crude oil.

This impact is reinforced by new, alternative technologies. As electric vehicles and heat pumps erode the maximum price consumers are willing to pay for oil products, they place a ceiling on the rents that resource owners can earn. Given that technology is only going to improve, the incentive to forgo oil production today in favour of producing when even better electric vehicles and heat pumps are available is likely to be a non-starter. So, these combined effects of lower costs and less rent extraction mean that more oil is available to consumers at lower prices than previously expected. Figure 10 shows that long-term oil price expectations are not just lower than they were during earlier oilsands booms — they are much, much lower.

Figure 10. Nominal Brent oil price forecasts, selected years from 2009 through 2025



Source: Author's graphic based on the U.S. Energy Information Administration's Annual Energy Outlook (AEO).
Note: Historical forecasts of nominal Brent crude oil prices from various editions of the Annual Energy Outlook, shown alongside the current AEO 2025 forecast.

Declining price expectations are especially bad news for new oilsands projects. These projects take a long time to come online and require large upfront capital expenditures per barrel, which are compensated for with long, relatively certain production lives.

Consider, for example, how these declining price expectations impact a project like Suncor's Fort Hills mine: In 2013, with WTI prices hovering around $100 per barrel and forecast to hit $200 per barrel by the mid-2030s, Suncor and its partners Teck and Total proceeded with the expected $13.5-billion expenditure on the oilsands mine. The project produced its first oil in 2018 and had an expected 50-year mine life. By that point, oil

prices had dropped dramatically, as had longer-term forecasts. Based on EIA forecasts, the net present value of the first 20 years of production at Fort Hills would have dropped by 35 per cent from the time of investment to the production of the first barrel of oil. Prices realized to date, combined with the EIA 2025 forecast, suggest the net present value of the first 20 years of production will be roughly half of what the forecast would have predicted in 2013 when the investment decision was made.

This decline in value was evident as minority partners Teck and Total sold their shares of the project, which implied a value for the entire project of less than $5 billion in 2023 — a little more than a third of the $17 billion it cost to build. Notably, these events happened over a period where global consumption was increasing.

It is prices that matter to oilsands projects, not global consumption. With prices projected to be weak for years to come, the case for new oilsands production — and a new oil pipeline — is harder to make.

What are the major hurdles to getting a pipeline built?

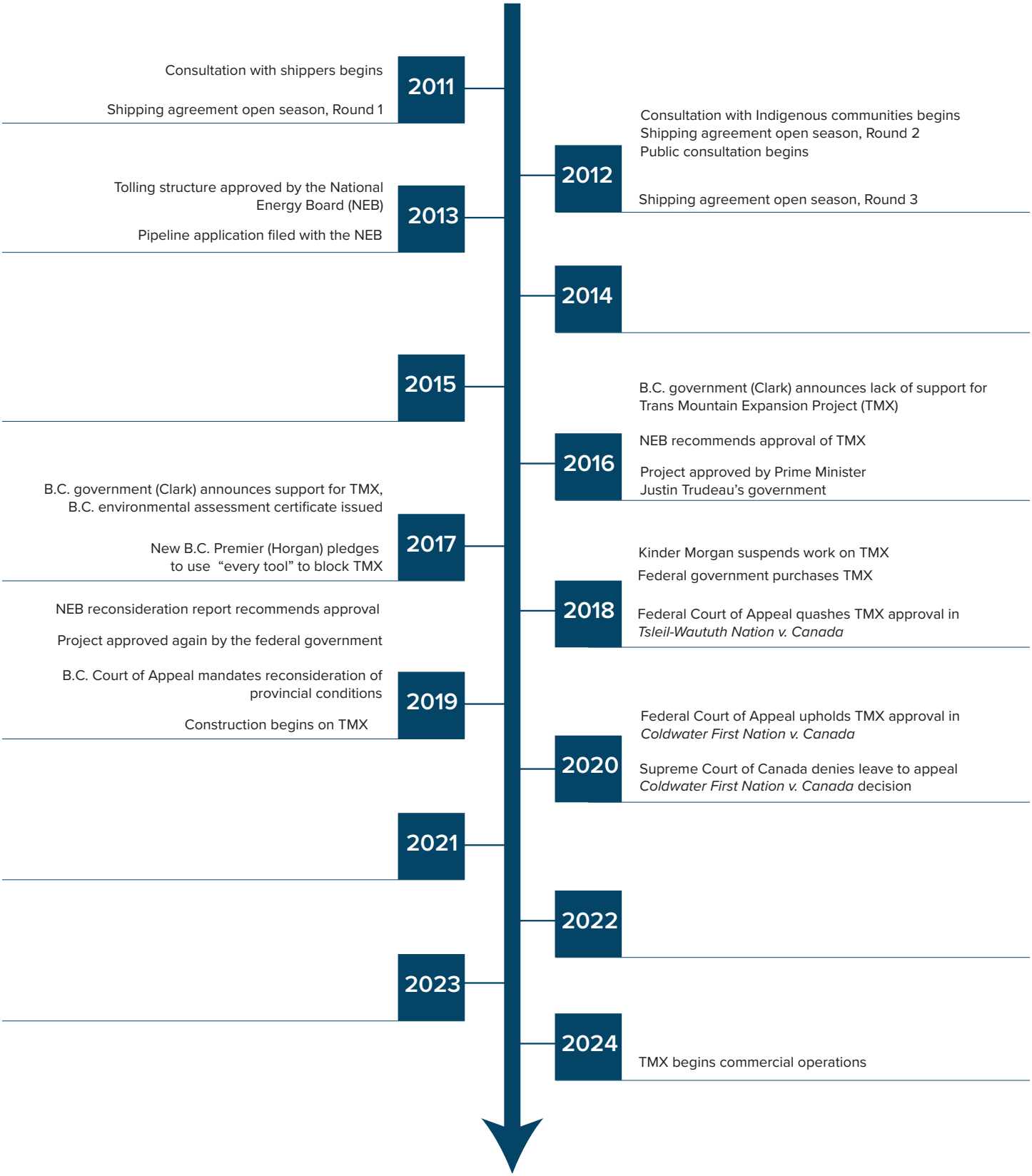
Any new pipeline will be expensive, time-consuming and fraught with controversy. The total cost of construction for TMX ballooned to over $34 billion, and the project took more than a decade from the application submission to delivery of the first oil shipments (NEB, 2016). Moreover, the application was filed after years of negotiations with shippers, and preliminary work on Indigenous consultations, public engagements, engineering and design, and tolling structure approvals (figure 11).

Pipeline rhetoric and the Carney government's *BCA* have focused on speeding up the regulatory process. This approach may miss the mark as, if anything, TMX was slowed down most by regulatory process shortcomings, not structural delays. The project received an initial recommendation for approval from the NEB in 2016, followed by project approval from the government of Prime Minister Justin Trudeau (Order-in-Council 2016-1069) in November of that year. However, this approval was quashed by the Federal Court of Appeal in *Tsleil-Waututh Nation v. Canada*. The court ruled that the duty to consult with affected Indigenous communities had not been met by cabinet, and the NEB process had not provided sufficient information to cabinet for such duty to be discharged.

A similar fate befell the 2014 approval of the Northern Gateway Pipeline (Order-in-Council 2014-809) which, too, was quashed by the Federal Court of Appeal for a failure by Prime Minister Stephen Harper's cabinet to uphold the Crown's duty to consult in *Gitxaala Nation v. Canada*. The Trudeau government subsequently cancelled the project in 2016.

In both cases, the issue was not that the process took too long, but that the process did not fulfil the Crown's constitutional requirements. Whether these shortcomings can be avoided through a new, abbreviated process of deemed approvals for projects of national interest remains to be seen.

Figure 11. Key events in the development of the Trans Mountain Expansion Project (TMX)



As it stands, it's unlikely that the process from conception to commercial operations will be materially shortened by the *BCA*. Canadian pipeline projects face a two-part review under each of the *Impact Assessment Act* and the *Canadian Energy Regulator Act*, two laws that were part of the much-maligned Bill C-69. The process hasn't changed much from that under previous legislation (Leach, 2021). Any pipeline proposal would be subject to an assessment of its environmental impacts, its design and the implications of its construction for the oil market and other pipelines. At the end of the regulatory process, federal cabinet would receive a recommendation from federal agencies. It will be tasked with deciding whether to permit the project and whether its environmental impacts are in the public interest. The names and procedures have changed, but having a political decision at the end of a technocratic process has been constant in Canadian law since the *Pipelines Act* of 1949. However, as critics will point out, processes have become longer, more detailed, more expensive and much more highly politicized since that time.

The *BCA* allows decisions like the final, political approval of a pipeline project to be pre-determined. Further, the *BCA* allows cabinet to exempt projects from requirements under other legislation. However, the *BCA* does not provide complete certainty for pipeline projects.

First, there is a regulatory override: a pipeline may not be added to the projects list until the Commission of the CER provides assurance that a deemed approval will not "compromise the safety or security of persons or regulated facilities" (BCA, 2025, ss. 15-18). More importantly, the law stipulates that a project may not be designated or be granted deemed approval under the *BCA* without consultation with Indigenous Peoples. The duty to consult is triggered whenever Crown conduct may affect potential or established rights of Indigenous Peoples. Meaningful consultation implies that the Crown be prepared to change its decisions and plans in light of new information, which is made more challenging by the nature of the deemed approvals offered in the *BCA*. Canadian courts have established that the types of rights and title claims at stake in pipeline projects require extensive and thorough consultation and accommodation, although such requirements do not confer a veto. The capacity for the government to consult sufficiently in advance based on the potential impacts of an undefined project to deem approval is highly speculative.

The Carney government will likely face an uphill battle in convincing the courts that the *BCA* can provide projects with upfront certainty of approvals through deeming, while maintaining a commitment to meaningful two-way dialogue with affected Indigenous Peoples on those decisions deemed to have already been made in favour of the project.

That hill is potentially a little steeper now, with the recent Federal Court ruling in *Kebaowek First Nation v. Canadian Nuclear Laboratories.* This ruling, currently under appeal, held that Canada's signature and adoption in federal legislation of the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) means that the Crown's duty to consult is pushed further to the deeper end of the consultation spectrum, bringing it closer to a requirement for consent from substantially affected First Nations.

At least one new pipeline proposal seems certain to materialize in Canada due to the active backing of the Alberta government and the added certainty offered by the *BCA*. However, whether the process triggered under this legislation can generate a judgment-proof set of regulatory approvals on a shorter timeline than we've seen with TMX or the Northern Gateway project is an open question.

Is it fair to say that the market should decide?

Parties on both sides of the pipeline debate are keen, in some cases, to say that the market should decide. Proponents may see little need for governments and regulators to concern themselves with the future need for a pipeline, judging that shipping contracts should carry the day (Breakenridge, 2025). More recently, as Prime Minister Carney touted nation-building projects, pipeline opponents have been quick to point out that no major companies have come forward to back such a new project (Bakx, 2025). A consensus appears to be emerging that the market should decide, but I fear it will last only until the market makes a clear choice.

In truth, a decision on a new oil pipeline cannot be left solely to the market. First, pipelines were built with the promise that the government would ensure that new infrastructure would not compromise existing carriers — that is why there is a needs assessment in pipeline legislation. Furthermore, just because a new pipeline could sustain itself, it does not mean it would be best for oil shippers as a whole. For example, a new pipeline west might be attractive to enough shippers to underpin its construction, but its operation could affect other pipelines. It could compromise the viability, or at least increase the costs, of shipping on the Enbridge Mainline by reducing its capacity utilization. That would likely be a net cost to oil shippers and decrease the value of Canadian resources.

The approval of a pipeline also comes with the heavy hand of the federal government wielded over landowners, municipalities and provinces. As we saw with Trans Mountain, the federal government can force a pipeline through over the objections of the provinces and, with appropriate consultation and accommodation, over the objections of affected First Nations. It is simply not appropriate for that sort of public involvement in a project without an assessment of whether it is in the public interest.

Pipelines also create substantial public costs and benefits. Insofar as pipelines raise the value of oil production, they increase royalties and taxes and improve the fiscal position of producing provinces. And, insofar as pipelines spur new development, they open resources that would otherwise be stranded, growing the value of our natural capital.

But there's a downside, too. With lower prices, the argument that pipelines enable material increases in greenhouse gas emissions becomes much more credible, because it is unlikely that production would happen without the new pipeline. And, of course, pipelines come with the risk of spills far from the production site and in areas that receive little benefit from the increases in royalties and taxes that pipelines bring. These are not decisions easily left to the market.

After weighing all the costs and benefits, it may well be the case that the public value of a pipeline exceeds its value to an individual proponent. This was, almost surely, what happened with Trans Mountain. Consider that mounting costs, regulatory uncertainty and disadvantageous tolling agreements led Kinder Morgan to abandon the project in 2018. No other private-sector proponent would have made a different decision under the circumstances. The market decided, as it were. But it was almost certainly in the public interest for the federal government to step in and build the project (Tombe, 2024).

A pipeline must have market support, as evidenced through long-term contracts with shippers and, perhaps, through investment decisions on related projects. However, the market alone can neither be the sole decision-maker nor the sole proponent of a pipeline if such a project is in the public interest. If a pipeline cannot be shown to be in the public interest, it will not — and should not — be built.

CONCLUSIONS

This paper shows how increased oil production in Canada and the United States changed the movement of crude oil in North America and altered price expectations in global crude markets. These market changes have moved Alberta's barrels further from premium markets, leading to higher-than-historic discounts to its crude relative to global benchmarks — even in the presence of unconstrained pipeline networks.

Before the opening of the TMX pipeline, infrastructure constraints further depressed valuations for Alberta's resources. New pipelines can reduce the costs of such constraints to Alberta bitumen and may, to a degree, ensure that our products sell close to global prices. However, we'll sell, at best, at a global price that factors in pipeline tolls — shipping costs that Alberta producers will absorb. The market for our oil is moving further from Alberta, and the costs of this shift will continue to mount, no matter how many pipelines we build. We used to benefit from a market willing to pay a premium for oil right next door. Our markets are now much further away and willing to pay no more for Alberta oil than for any other.

Moreover, building new pipelines will not be easy. The commercial case for a pipeline will be challenged by forecasts of low oil prices. And despite the efforts of Prime Minister Carney's government, it seems unlikely that new legislation will offer regulatory certainty and judgment-proof approval for a prospective pipeline.

I rely extensively on forecasts in this paper and, in some cases, show how our views of the oil market of tomorrow can be very wrong. Most of us didn't expect oil prices of $100 per barrel, nor did we expect a world where daily demand of over 100 million barrels could yield prices below $50 per barrel. We did not expect the United States to become far less dependent on Canadian crude oil, and in hindsight, we might not have built as many pipelines to serve its refineries.

At the same time, some points I make in this paper rely on forecasts that will, almost certainly, also prove incorrect. Perhaps $200-per-barrel oil prices lie just around the

corner. Maybe new technology will continue to evolve to the point where $50-per-barrel oil seems impossibly expensive.

The point is, we can't know. We can only draw lessons from the past and hope they make us better able to adapt to the oil market of the future. Another oil pipeline in Canada is neither a pipe dream nor a panacea — it is a major capital investment in an increasingly uncertain market. Any policy response should be based on a transparent assessment of both the risks and the rewards for Canadians.

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GLOSSARY

API gravity: The American Petroleum Institute gravity (API gravity) is a measure of how heavy or light a petroleum liquid is in relation to water.

Apportionment: A process that occurs when total shipper nominations for crude oil or refined products exceed a pipeline's available capacity in a given month. Under the tariff in effect, each shipper's volume is proportionally reduced. Apportionment results from capacity constraints, which may be caused by increased production or heightened market demand.

Brent crude: A light, sweet crude extracted from the U.K. North Sea that serves as the international benchmark to price oil.

Brownfield: Existing oil fields or facilities that are modified or expanded to extend their economic producing life.

Canada Energy Regulator (CER): Federal agency responsible for regulating pipelines, energy development and energy trade in the public interest. It replaced the National Energy Board (NEB) in 2019.

Common carrier: A pipeline company required to transport all offered products without contract and usually by monthly nominations, allocating capacity among users when demand exceeds availability.

Greenfield: A new oil and gas field development where no prior production infrastructure exists.

Heavy crude: Crude oil with high viscosity and density greater than 900 kg/m^3, typically corresponding to an API gravity below 25.

Light crude: Crude oil with low viscosity that flows readily at room temperature.

Light tight oil (LTO)/Tight oil: Oil extracted from low-permeability formations, such as the Bakken or Eagle Ford, which require hydraulic fracturing to produce at commercial rates.

National Energy Board (NEB): Federal agency that was responsible for regulating pipelines, energy development and trade in the public interest. Established in 1959, the NEB was replaced by the CER in 2019, which oversees energy exports, project reviews and safety enforcement.

Oil futures: Standardized contracts for oil delivery at a set future date for a predetermined price, used to hedge against price volatility.

Shale oil: A subset of tight oil.

Sour crude: Sour crude has higher sulphur levels than sweet crude and is more costly to process.

Sweet crude: Sweet crude has a low sulphur content and requires less refining than sour crude.

Tidewater: Access to marine ports, coastal terminals or tanker facilities.

Tight oil: See Light tight oil.

West Texas Intermediate (WTI Cushing): A crude stream produced in Texas and southern Oklahoma that serves as a benchmark for pricing other crude streams and is traded at the Cushing, Oklahoma, hub.

Western Canadian Select (WCS): Canada's largest heavy crude oil blend, composed of bitumen, conventional oil, synthetic crude and condensate.

WTI-WCS differential: The price difference between light, sweet West Texas Intermediate (WTI) crude traded at Cushing, Oklahoma, and heavy, sour Western Canadian Select (WCS) crude priced at Hardisty, Alberta, reflecting quality differences and transportation costs.

Sources: (CAPP, 2023; CER, 2022, 2025e; EIA, n.d.-a, n.d.-b, 2013; IEA, 2022; NEB, 2013; Oil Sands Magazine, 2018, 2022; Schlumberger Limited, n.d.).



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