TRACKING EMISSIONS:

THE CLIMATE IMPACT OF THE PROPOSED CRUDE-BY-RAIL TERMINALS IN THE PACIFIC NORTHWEST

OILCHANGE INTERNATIONAL

Sightline INSTITUTE

NOVEMBER 2015

Ex5579-000056-CRK

This report is published by Sightline Institute and Oil Change International.

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EXECUTIVE SUMMARY

The Pacific Northwest (PNW) states of Oregon and Washington are facing a quadrupling of their crude-by-rail terminal capacity, to over a million barrels a day. This report aims to examine the impact that expansion would have on climate change, by unlocking carbon from its safe geological home to be released into the atmosphere.

MORE OIL TRAINS, MORE OIL SHIPPING

Based on an economic analysis, we predict that the terminals would have high rates of utilization compared to unloading terminals elsewhere, which are often used at a fraction of their full capacity. We estimate that:

- **If all new terminals are built as planned, they would likely achieve utilization rates of around 75%, unloading up to 545,000 barrels per day (545 kbd) of crude.**
- **This would entail around eight extra unit trains, each with over 100 tank cars of crude, passing through the PNW per day.**
- **The terminals would add between one and three extra vessels per day carrying oil in the PNW's coastal waters,** with the attendant risks. A maximum of around 100 kbd from the new terminals would be destined for the refineries in Puget Sound (in 2020). The remainder would be shipped on, mostly to California.
- F**or some of the proposed terminals, export of tar sands to Asia would be economically attractive to companies.** The operator of the largest proposed terminal, Tesoro-Savage, has said that there are no plans for such export, but there are no binding commitments or legal restrictions on the possibility. It is unclear what impact the proposed lifting of the U.S. crude oil export ban would have on the use of these terminals.

The reason for high projected utilization rates is that oil producers in the Bakken shale of North Dakota or the tar sands of Alberta would obtain greater profitability by sending their oil to the West Coast by rail than by sending it to the Gulf Coast or East Coast. This is because the transport cost to the PNW is lower than other rail routes, and only slightly greater than pipelines to the Gulf. Meanwhile, sales prices are higher, because traditional West Coast supplies (Alaska and California) are declining whereas Gulf Coast supplies are increasing.

In fact, our economic estimates, combined with potential supply and demand volumes, suggest that there may even be proposals for more PNW rail terminals in the future.

DRIVING EXPANSION OF TAR SANDS

New research by Oil Change International has found that the pipelines and refineries currently taking crude oil from Canada – including the tar sands – are nearly full, and could not accommodate any expansion in tar sands production.

Following the unprecedented public opposition to the Keystone XL pipeline, President Obama committed not to approve the project if it significantly exacerbates carbon pollution. In fact, all of the major proposed new pipelines from Canada are facing massive public and political opposition, and legal challenges, with now a very real possibility that none will be built.

Other potential rail routes out of Alberta are too costly, making unviable any new tar sands development that relies on them. However, this report finds that rail to the PNW could make new tar sands expansion profitable:[1]

- **In the absence of new pipelines, the PNW rail terminals would be the sole driver of new growth in the tar sands.**
- **They would potentially unlock 154-275 kbd of new bitumen production, and/or up to 215 kbd of new synthetic crude production (by 2030) that would otherwise not be extracted.**
- **The resulting greenhouse gas emissions from this would be between 41 and 106 million metric tons/yr of carbon dioxide equivalent (CO_2e) – the equivalent of 9-22 million cars.**

1 These results are based on the U.S. Energy Information Administration's reference-case oil price forecast. It should be noted that tar sands project approvals are very sensitive to price: if prices rose above expectation, and were then expected to stay higher, the impact of PNW rail terminals would be diminished, as more costly export routes could become viable.

ADDING TO FRACKING

We find that sending crude from the Bakken shale by rail to the PNW, and/or barging it on to California, would deliver significantly higher returns to producers than sending Bakken crude to either the Gulf Coast or the East Coast.

The Bakken economics are much harder to predict, as they are considerably more fluid than the tar sands, and we also do not know yet the full impact of the fall in oil prices. The North Dakota Department of Mineral Resources and RBN Energy have estimated how varying netbacks may impact production rates. Noting that any such analysis is necessarily highly tentative, we estimate that the higher profitability of Bakken production arising from PNW rail relative to alternative destinations could unlock new production:

- **The PNW terminals could lead to a direct production increase by 2018 of up to 114 kbd, compared to what would be produced in the absence of the terminals.**

- **The resulting greenhouse gas emissions from this extra production would be up to 30 million metric tons/yr of CO_2e – equivalent to 6 million cars.**

On top of these direct impacts, the PNW terminals would have unquantifiable, indirect impacts on Bakken production. The key economic function of crude-by-rail is to provide flexibility to producers, both reducing production risks and creating opportunities for arbitrage. Increased profits could also relieve financial stresses faced by the over-leveraged producers.

FAILING THE CLIMATE TEST

President Obama's commitment to assess the Keystone XL pipeline based on its greenhouse gas impact was an important step towards recognizing that fossil fuel extraction cannot be further expanded in a climate-constrained world. If our institutions are serious about averting the worst impacts of climate change, such a climate test should become a standard part of any decision on infrastructure or policy.

Our analysis finds that if the proposed rail terminals were built in the PNW, they would add significantly to the carbon extracted and burned, exacerbating climate change. Clearly then, the terminals would fail a climate test. Indeed, permitting these terminals would be permitting dangerous climate change.

LIST OF ABBREVIATIONS

ANS	Alaska North Slope, a grade of crude oil
API	American Petroleum Institute. API gravity is a measure of the density of crude oil
BC	British Columbia
bbl	barrel
CO_2e	carbon dioxide equivalent, a measure of greenhouse gas emissions
dilbit	diluted bitumen, i.e. tar sands bitumen with a diluent added (condensate or light crude) to enable it to flow in pipelines
DMR	Department of Mineral Resources (of North Dakota)
DWT	deadweight tonnage: the weight a ship can carry
EIA	Energy Information Administration
GT	gigatons (metric)
IRR	internal rate of return, a measure of profitability of a project
kb	thousand barrels
kbd	thousand barrels per day
LCFS	Low Carbon Fuel Standard (of California)
LLS	Louisiana Light Sweet, a grade of crude oil
MT	megatons (metric)
NPV	net present value, a measure of a project's future incomes minus expenditures, adjusted for the 'time value of money'
PADD	Petroleum Administration for Defense District (first used in the Second World War). The US energy market is broken into PADDs 1 (East Coast), 2 (Midwest), 3 (Gulf Coast), 4 (Rockies) and 5 (West Coast). PADD 5 comprises Alaska, Arizona, California, Hawaii, Nevada, Oregon and Washington.
PNW	Pacific Northwest
VLCC	very large crude carrier, the second-largest class of oil tanker vessel (after ULCC = ultra-large)
WTI	West Texas Intermediate, a grade of crude oil, and the most important benchmark in North America, against which other crudes are priced
yr	year

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1. INTRODUCTION

The states of Washington and Oregon are facing a quadrupling of their crude-by-rail terminal capacity to over a million barrels a day. This report aims to examine the impact that expansion would have on unlocking carbon and thereby exacerbating climate change.

CLIMATE CHANGE AND THE FOSSIL FUEL SUPPLY SIDE

Historically, much of climate policy has focused on the point of emission of greenhouse gases, where fossil fuels are consumed. However, the problem is caused by the quantity of fossil fuels, which can be assessed at either end of the supply chain, as the same amount is consumed as is extracted.[2] Discussions of climate change are now increasingly turning to the supply side, the extraction of fossil fuels.[3]

Climate change is driven by the concentration of greenhouse gases in the atmosphere, which is determined by their cumulative emissions over all time, rather than by their rate in any particular year. According to the Intergovernmental Panel on Climate Change (IPCC), only a further 1,000 metric gigatons (GT) carbon dioxide can be released into the atmosphere in order to have a two-in-three chance of meeting the internationally agreed goal of keeping temperature rise below 2°C.[4]

Fossil fuel reserves constitute potentially extractable, and hence potentially emittable carbon. Given that the world's proven oil reserves currently amount to 1,700 billion barrels,[5] at least half of this must ultimately be left in the ground to protect against a significantly disrupted global climate.

Some commentators (e.g. Levi 2015) argue that there is little climate benefit in a country reducing its extraction of fossil fuels, because any reduction would be offset by an increase in another country. In reality, this 'leakage' of supply-side measures occurs only partially, just as it does with demand-side measures.[6] If a country reduces its oil extraction, this will increase the price, which may encourage greater extraction elsewhere.

It is clear that leakage is neither zero nor 100%. Consider for example, how two supply-side factors – increased shale production in the United States and OPEC's decision not to cut production in response – led to the collapse in oil price, which in turn led to the largest oil demand growth in five years (Kemp 2015b).

Perhaps part of the reason for supply-side skepticism is the existence of a 'swing producer' in the oil market. In fact, the role of OPEC never led to 100% leakage, as OPEC's ability to act was always limited by physical, political and economic factors. If it had, the oil price would not have fluctuated. But if the swing-producer effect was once partially relevant, it is not now that Saudi Arabia and OPEC have decided not to fulfill that role, and instead to maximize their production.

The degree of leakage is determined by the economic concept of price elasticity: the degree to which demand or supply changes in response to price signals. The trouble is that there is disagreement on what the elasticities actually are, especially in relation to supply. Since OPEC decided in November 2014 not to reduce its oil production to shore up the price, the financial pages have been full of debate on the extent to which production elsewhere will be cut back in response. While many companies have announced reductions in capital investment, it is still too early to judge the impact of the price fall on production.

For this reason, we do not go into the question of leakage in this report. Just as demand-side policies are generally discussed in terms of their direct impact on emissions (i.e. assuming no leakage), we take a similarly simplified approach

2 Apart from minor changes in inventories
3 For example, U.S. Climate Envoy Todd Stern (Goldenberg 2014), Bank of England Governor Mark Carney (Clark 2015)
4 IPCC 2013, p.31
5 BP 2015b
6 The converse argument to that of the supply-side skeptics is that there is little point in a country reducing its consumption of fossil fuels (and emissions) because if it doesn't burn them, then someone else will. In reality, if a country reduces its oil consumption, the effect will be to lower the price, which may encourage another to use more.

here, assessing simply the amount of production unlocked, and not its indirect effect on production elsewhere.

MIDSTREAM OIL INFRASTRUCTURE

Midstream infrastructure such as pipelines and rail, to transport crude oil to refineries, is a key part of the transmission system that carries carbon from below the ground to the atmosphere. Whereas the extraction of fossil fuels can be measured by the volume of carbon dug out of the ground, for midstream infrastructure it is its facilitating role that is key. How much carbon would be additionally extracted and combusted that otherwise would not have been?

Having declined since 1970, U.S. oil production has grown dramatically in the last seven years, driven by the combination of hydraulic fracturing and horizontal drilling unlocking hydrocarbons trapped in shale rocks, primarily in the Bakken formation in North Dakota, and the Permian and Eagle Ford in Texas. Meanwhile, extraction of tar sands from Alberta has more than doubled in the last ten years, to over 2 million barrels per day. The United States and Canada now account for over 17% of world oil production.[7]

Rail transportation of crude oil in the U.S. has increased rapidly since 2010, and has been a major factor facilitating the growth of shale production, especially in the Bakken. And with pipeline proposals stalled, rail is also playing a growing role in exporting tar sands from Canada. It is rising oil production in these two areas that PNW rail terminals would help facilitate.[8]

Across North America, citizens have argued that new fossil fuel infrastructure should not be built, as it would both exacerbate the climate crisis, and put their communities at greater risk from spills and accidents. In the Pacific Northwest, both coal export terminals and crude-by-rail facilities have been met with public protest, court cases and increased regulatory scrutiny. Many have been significantly delayed, downscaled or suspended.[9]

METHODOLOGY

This report aims to evaluate the extent to which the PNW rail terminals would contribute to climate change by unlocking new carbon, based on a best estimate of how they would be used, as envisaged by the oil industry. It uses the tools used by the oil industry to analyze the economics of transportation, and consequently of extraction.

Sources of Crude

It focuses on the two main[10] sources of crude that would be handled by the terminals: the tar sands of Alberta and the light oil extracted using hydraulic fracturing (fracking) from the Bakken shale of North Dakota. Around half of current tar sands production is upgraded (partially refined) near the extraction site, to form synthetic crude. The rest remains as bitumen, but is diluted with condensate or light oil to form 'dilbit', which unlike the viscous raw bitumen can flow in pipelines.

Economics Is Key

As crude-by-rail has expanded across the U.S., its proponents have highlighted flexibility as its major advantage to oil shippers. In contrast to pipelines, new terminals can be built quickly and at low capital cost, using the existing network of track. However, the per-barrel operating costs are higher than for pipelines.[11] In consequence, whereas pipelines mostly tend to be used at 80% or more of their capacity (apart from some older, semi-obsolete ones), rail infrastructure is often used at a small fraction of its physical capacity. For example, in 2014 unloading terminals on the Gulf Coast had average utilization rates of just 16%.[12]

7 BP 2015b
8 They would also likely receive crude from fields in Wyoming, Utah and possibly Colorado. The growth in these states is smaller, so oil transport from these states to the PNW is not assessed in this report.
9 de Place 2015b
10 Smaller quantities might come from fields in Wyoming and Utah, which are not assessed here.
11 As Sandy Fielden (2013c) of RBN Energy illustrates: A new terminal handling 100-car unit trains might cost $50m to build, including storage tanks. A unit train contains 100 x 650 = 65,000 bbl. At a conservative 2 trains a week, the terminal operator gets $1.50 per bbl or $195m in revenue. That works out at $10m per year or a 20% return on the $50m investment. The payback period is 5 years. If the terminal handles 4 trains a week, the payout doubles and the payback period falls to 2.5 years. Compared to the billions of dollars spent on pipelines, the investment required is minor.
12 255 kbd unloaded (EIA 2015f); 1,600 kbd capacity (Oil Change International 2015)

For this reason, we cannot look just to the capacity of the proposed terminals to assess their climate impact: instead we need to also use economic analysis to estimate how much they would actually be used. We use the same analytical tools the industry uses for the purpose of making its investment decisions. Key to this approach is the concept of the netback price: the amount producers receive for their oil in a particular market, minus their cost in getting it there. In general, producers will send their oil to wherever they can get the highest netback.

This report estimates average netbacks that producers would obtain by railing dilbit, synthetic crude or Bakken oil to the PNW, compared to alternative destinations such as the Gulf or East Coasts. This comparison of netbacks allows us to estimate how much the PNW terminals would be used.

Unlocking Carbon

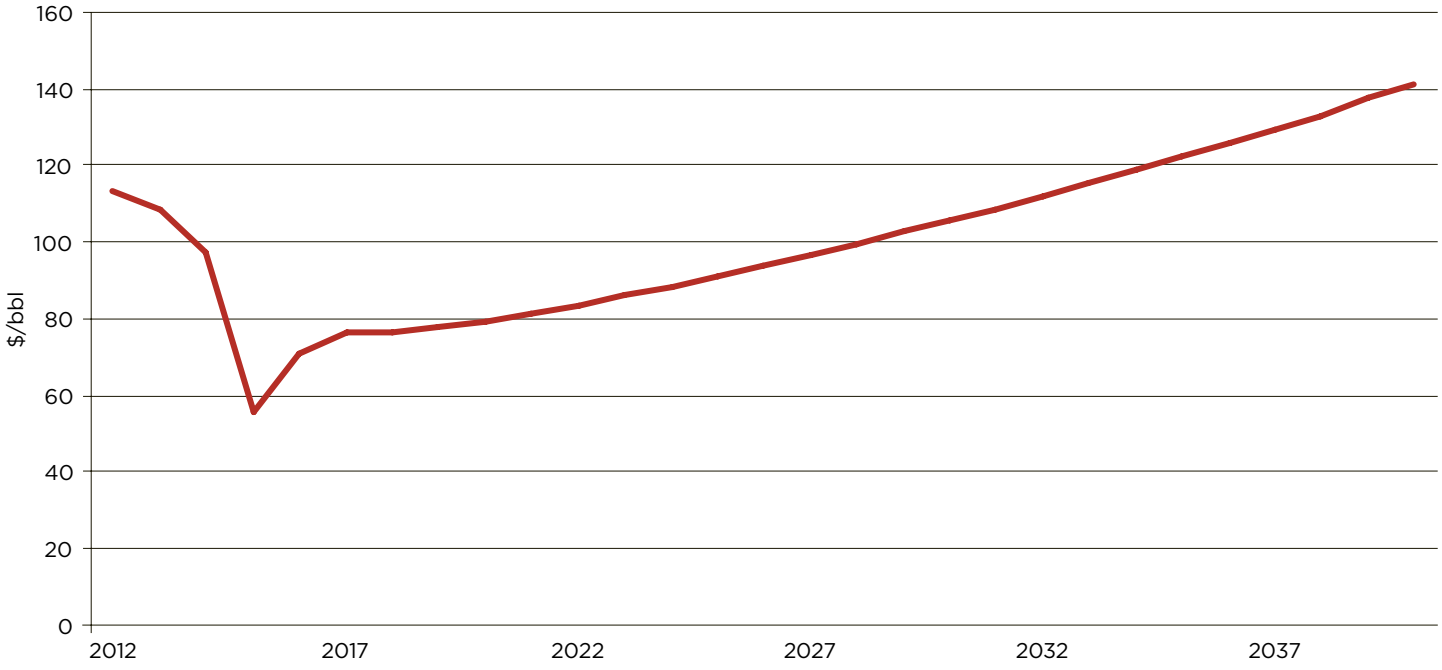
The report then goes on to estimate the new carbon that would be unlocked if the terminals were built, but which would remain in the ground if they are not. This is done by assessing the extent to which production would be economically viable given PNW netbacks, compared to the next-best available netbacks.

For the tar sands, a project relies heavily on a single investment decision, which will set the course for the coming decades. To model that decision, we use cashflow analysis, economic data from Rystad Energy's UCube database, to evaluate the internal rate of return for some representative projects. We assume that companies will decide to proceed with projects whose IRR exceeds 10.5% and reject those with IRR below 9.5%. Between 9.5 and 10.5%, we assume that the project is considered marginal, and may or may not go ahead. We then use breakeven prices from the Rystad UCube, to extrapolate from the sample projects to estimate the impact on tar sands production as a whole.

In contrast to tar sands, shale fracking is highly fluid, with decisions made almost on a weekly basis about where and whether to drill. As a result, the economics are determined largely at the level of an individual well, rather than a whole project. We therefore need to use a different approach for the Bakken. In this case, we use estimates from the North Dakota Department of Mineral Resources of how price affects drilling rates, well productivity and hence production.

Given the potential for volatility in the oil market over extended time periods, no oil price forecast is likely to turn out accurately over 20 or more years. We use the Energy Information Administration's

Chart 1.1: EIA Reference Case Brent Price Forecast Source: Energy Information Administration (2015a)



(EIA's) current Reference Case forecast, which sees prices climbing back to $100 per barrel by around 2030, as we think it is the closest available approximation to the price forecasts that oil companies may use to make decisions about investing in oil projects. In Appendix 3, lower and higher oil price scenarios are considered.

It should be noted that we do not endorse the EIA Reference Case or its use for making decisions on energy policy or investment. It is a business-as-usual scenario that assumes U.S. energy policies remain as they are today. U.S. greenhouse gas emissions associated with it are at least 190% higher in 2040 than if the U.S. was making progress towards its stated climate goal of constraining climate change to 2°C.[13] Using the Reference Case implies a failure to address climate change. We have used this forecast here because we are assessing the greenhouse gas impact of these terminals going ahead, which – as we conclude – does not reflect a climate-safe energy path.

STRUCTURE OF THIS REPORT

In Section 2, we consider the physical capacity of the terminals, which obviously places an upper limit on their usage, and also their location relative to refineries.

In Sections 3 and 4, we estimate the potential demand for new oil from the terminals, respectively in Washington and California. This is followed, in Section 5, by consideration of whether exports to Asia are also feasible.

Section 6 contains the central calculation of the report: what netbacks would producers expect to obtain for their oil by sending it to the rail terminals in the PNW, compared to alternative markets.

In Section 7, we consider what volumes would likely be transported to the PNW terminals. We use the netback analysis of Section 6 to put potential markets in producers' order of preference, and then the volume limits from Sections 2-5 to assess how much could go to each.

In Sections 8 and 9, we apply the netback analysis to the upstream economics of tar sands and Bakken production, in order to assess whether they might permit new carbon to be extracted that would be otherwise unviable, also bearing in mind the physical limitations explored in Sections 2-5.

Finally, in Section 10, we convert the findings of Sections 7-8 into greenhouse gas emissions, and we use the volume assessment of Section 7 to consider possible further indirect impacts of the terminals.

This is followed by a full bibliography of sources used to compile this report. Appendices 1-2 show the detailed calculations used to estimate netback prices. Appendix 3 asks the 'what if?' question, to consider how our results might change if oil prices or other factors turned out differently.

13 McKinnon 2015, pp.8-9

2. THE PROPOSED TERMINALS

Crude-by-rail first arrived in the Pacific Northwest in 2012, with a shipment of Bakken crude to Tesoro's refinery terminal on Puget Sound. Since then, crude-by-rail unloading capacity has grown to seven offloading terminals, with a capacity of 250,000 barrels a day (250 kbd). Expansion is proposed for one of these, as are five new terminals: if all are built, capacity would quadruple, to nearly one million barrels a day.

Four of the existing terminals, and one of the proposed, are located at refineries. Deliveries to these terminals will supply the refineries themselves, as it would make little economic sense for the producer, refiner or shipper to incur additional transport costs by sending the oil elsewhere and sourcing a different crude for the refinery. The possible exception is during the times when the refinery is offline for maintenance (either planned or unplanned), when the site could potentially function as a marine transloading terminal while refining was suspended.

The non-refinery terminals would load onto barges (or in some cases coastal tankers), for delivery either to the Washington refineries or to California. We also consider the possibility of whether they could be used for exports to Asia, either for tar sands oil now, or for U.S. oil in the future if the crude export ban were lifted.

Table 2.1: Capacity of Existing and Proposed Terminals / kbd

	Refinery	Non-refinery	TOTAL
Existing capacity	195	88	283
Proposed additions	60	667	727
TOTAL	255	755	1,010

Table 2.2: List of Existing and Proposed Terminals Sources: regulatory filings; company reports; Reuters (2015); Sightline Institute (de Place 2015a); Oil Change International (2015) media reports

Operator	City	Current capacity / kbd	Proposed additional capacity / kbd	Status	Facility type	Railroad
Existing terminals:						
BP	Cherry Point, WA	70			Refinery	BNSF
Phillips 66	Ferndale, WA	35			Refinery	BNSF
Tesoro	Anacortes, WA	50			Refinery	BNSF
U.S. Oil Refining	Tacoma, WA	40			Refinery	BNSF
Targa	Tacoma, WA	40			Vessel transload	BNSF
Arc Logistics	Portland, OR	16			Vessel transload	UP
Existing terminals proposed expansions:						
Global Partners	Clatskanie, OR	32	87	Received state emissions permit allowing expansion; startup expected 2016	Vessel transload	BNSF
Proposed new terminals:						
Shell	Anacortes, WA		60	Awaiting permits	Refinery	BNSF
Imperium	Hoquiam, WA		74	Existing biodiesel facility seeking permit to add crude-by-rail capability and additional storage. Environmental review ongoing	Vessel transload	PSAP connects to BNSF / UP
Westway Terminals	Hoquiam, WA		49	Seeking permits	Vessel transload	PSAP connects to BNSF / UP
Grays Harbor Rail Terminal	Hoquiam, WA		45	Seeking permits, environmental review ongoing	Vessel transload	PSAP connects to BNSF / UP
Riverside	Longview, WA		30	Concept stage	Vessel transload	BNSF
Tesoro-Savage joint venture[14]	Port of Vancouver, WA		360	Approved by port, awaiting Governor decision 2016 following environmental review now due late November 2015	Vessel transload	UP, BNSF
NuStar	Port of Vancouver, WA		22	City hearings examiner ruled in October 2015 that project must undergo a detailed environmental impact review	Vessel transload	UP, BNSF

14 Also known as Vancouver Energy

3. THE PNW OIL MARKET

The most direct market for oil unloaded at the PNW terminals is in the region itself.

REFINERY DEMAND

All five of the PNW's refineries are located in Puget Sound, Washington. Two have coking configurations, capable of processing heavy oil such as diluted bitumen (dilbit). Table 3.1, below, shows the capacity of these refineries for total crude and for heavy oil.

The refined products are distributed by pipeline (49%), by ship and barge (40%), and by rail and truck (12%). In 2011 about 35% of the products produced in these refineries was sold in other U.S. states, mainly in Oregon and California, and about 14% to foreign consumers, mostly in British Columbia.[15]

SOURCES OF SUPPLY

Crude oil arrives in Washington from four sources, and by six routes:

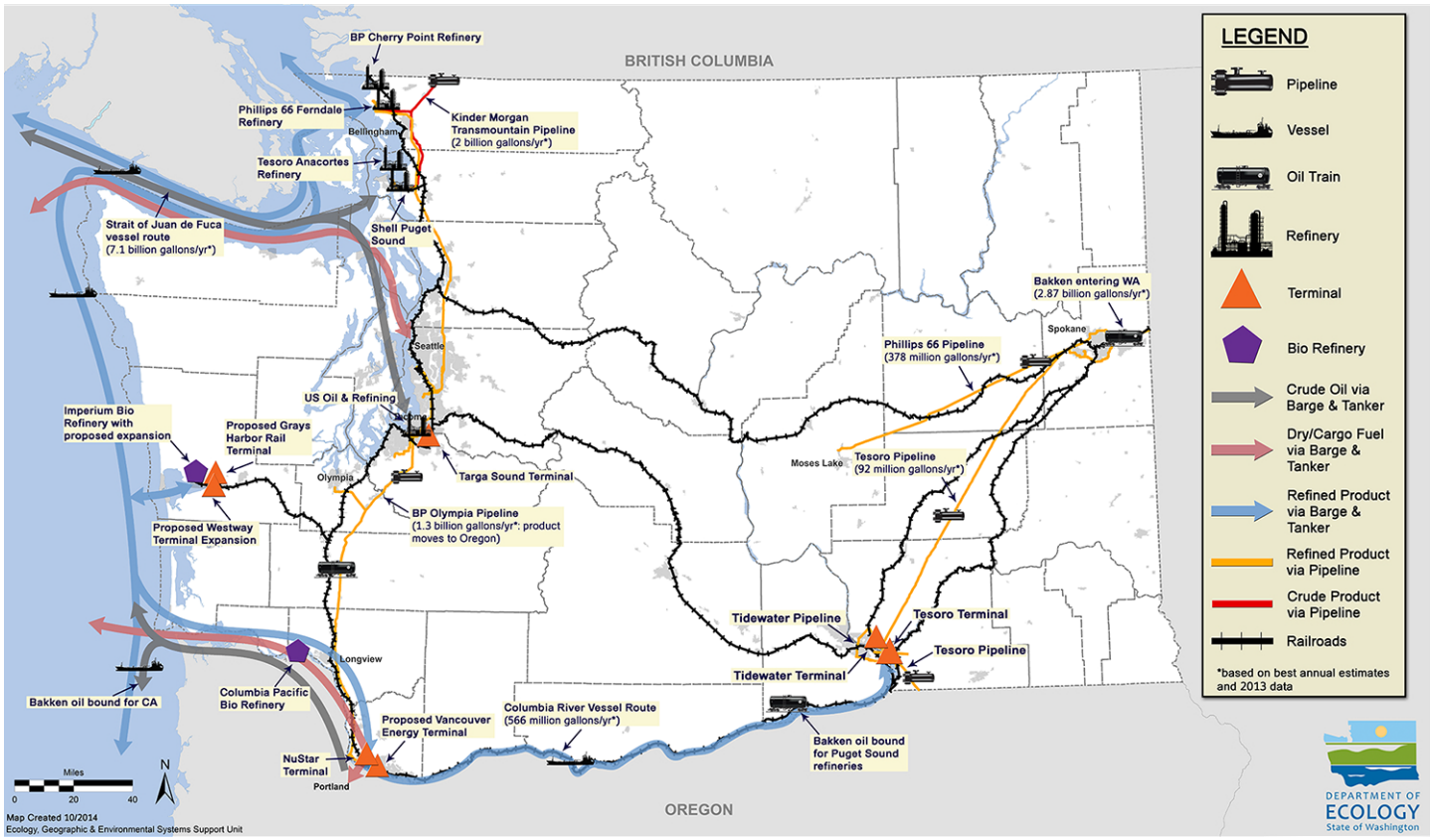
- Alaska: by tanker ship;
- Canada (both conventional and tar sands):
  - by Trans Mountain pipeline to refineries;
  - by Trans Mountain pipeline to Westridge Terminal, BC, then barge to refineries;
- Other U.S. (mainly from the Bakken shale):
  - by rail to refinery terminals in Puget Sound;
  - by rail to Clatskanie terminal on the Columbia River, then barge to refineries
- Other imports: by tanker ship.

Table 3.1: Refineries in the PNW Source: Energy Information Administration (2015d)

Corporation	Site	Configuration	Capacity / kbd	Heavy oil capacity / kbd
BP	Ferndale	coking	225	140
Phillips 66	Ferndale	cracking	101	
Shell	Anacortes	coking	145	56
Tesoro	Anacortes	cracking	120	
US Oil & Refining	Tacoma	hydroskimming	41	
TOTAL			632	196

15 Department of Commerce 2013, pp.32, 34

Oil Movement in and out of Washington State Image credit: Washington Department of Ecology (2015, p.38)



The breakdown of these sources is shown below.

Chart 3.1. Washington State Crude Oil Receipts, 2013 Source: Energy Information Administration (2015c); Washington Deptartment of Ecology (2015 pp.32, 284)

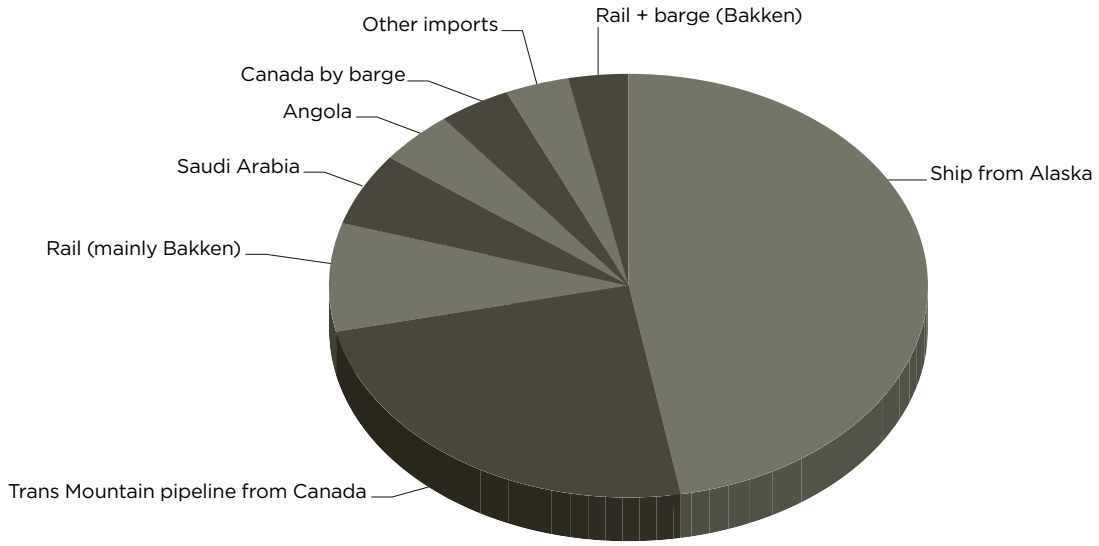


Table 3.2: Washington Imports by Type, 2014 / kbd[16] Source: Energy Information Administration (2015d). Note all figures rounded to nearest whole number, so totals may not precisely match.

	Heavy	Medium	Light	TOTAL
Canada	32	57	78	167
Latin America	15	0	1	15
Middle East	1	9	8	18
Other	7	4	4	15
TOTAL	54	70	90	215

POTENTIAL DEMAND FOR NEW CRUDE FROM PNW TERMINALS

The potential market for new oil in Washington comes from three areas: offsetting declines in Alaskan oil production, offsetting declines in Canadian conventional crude, and displacing shipborne imports from outside North America.

The largest potential market for the terminals is in offsetting declines in Alaskan production, which is expected to fall from around 500 kbd today to 400 kbd by 2020. Washington receives about half of Alaska's production.

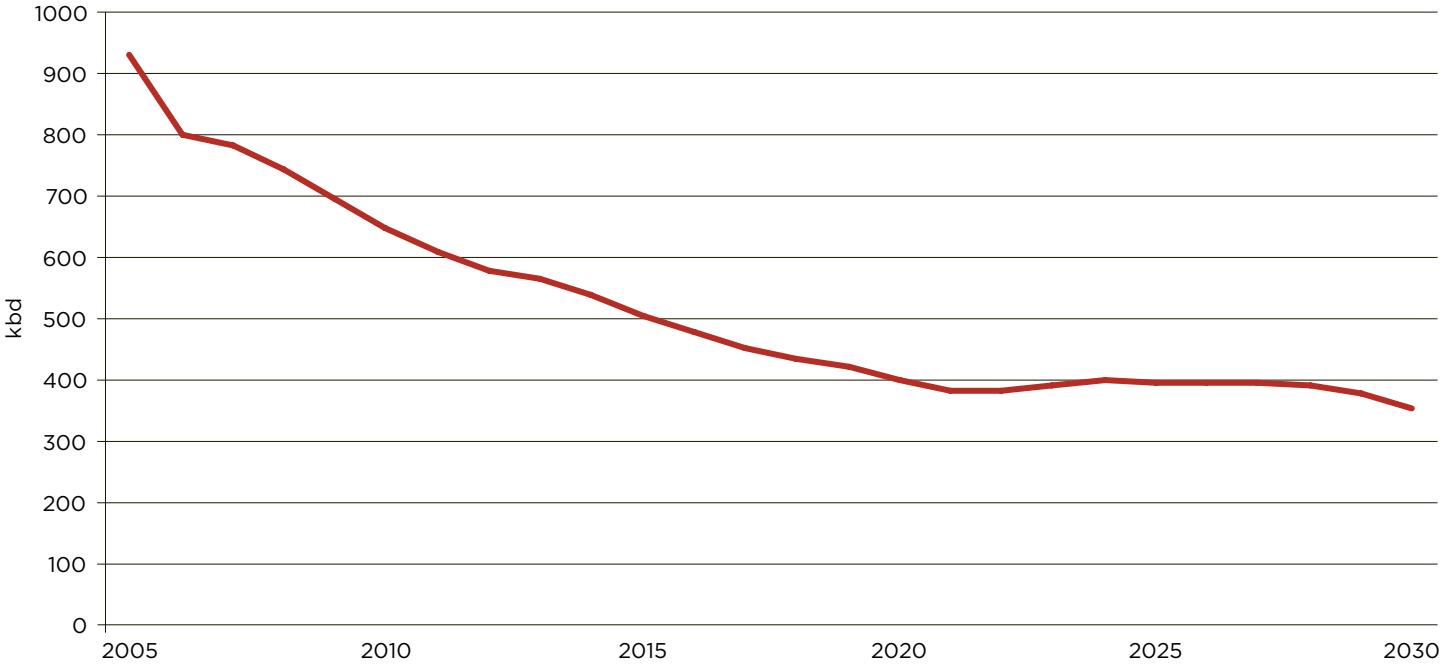
Canadian conventional production is also declining: it is expected to fall from 1,430 kbd today to 1,230 kbd by 2020 and 1,000 kbd by 2023.[17] However, the Trans Mountain pipeline is likely to continue to be used at capacity, since it provides cheaper transportation than other alternatives. Thus any reduction in the volumes of conventional crude in the pipeline will be offset by tar sands replacing it in that pipeline, so the remaining market for crude-by-rail – after volumes supplied by the pipeline – will be unchanged.

Non-Canadian imports account for just 14% of Washington's oil demand; the potential market for displacement is around 50 kbd.

There is thus a potential market as shown in Table 3.3 (assuming declines in Alaskan production translate proportionately to its markets). Note that we have classified reduced Alaskan production as creating a market for heavy oil, because of its high content of residual oil.[18]

Note also that here we are assessing demand in this market. The displaced imports do not constitute oil left in the ground, but rather oil that would go elsewhere, such as Asia (except to the extent of price factors reducing production – see Section 1).

Chart 3.2: Alaska Oil Production and Forecast Source: Rystad UCube



16 We categorize heavy oil as having API gravity < 27° and light oil > 35°. The definitions of heavy, medium and light vary widely within the industry, with some putting the light-medium threshold as low as 21°. Our categorization follows EIA 2015b.

17 Rystad UCube

18 Although Alaska North Slope crude is classified as a medium crude, due to having API gravity of 31°, in fact it contains an unusually high proportion of residual fuel oil (BP 2015a), which is processed using a coking unit – the reason Shell and BP refineries have cokers, despite receiving relatively little heavy oil. (Crudes with API gravity above 30° usually contain less than 20% residue, whereas ANS has 44%. See also Stockman 2013, p.28; and Gordon 2012, pp.13-16).

Table 3.3: Potential Market for New Crude-by-Rail in Washington, 2020 / kbd

	Heavy	Medium	Light
Offset Alaska reductions	55	0	0
Offset Canada conventional reductions	0	0	0
Displace non-Canadian imports	23	13	13
TOTAL	78	13	13

4. THE OIL MARKET IN CALIFORNIA, ALASKA AND HAWAII

We saw in the previous section that extra demand in the PNW itself is limited; we now conduct the same exercise for other U.S. West Coast markets.

CALIFORNIA REFINERY DEMAND

California's oil market is three times the size of Washington's. It has seventeen refineries, ten of them with coking configurations.

During the first six months of 2015, PADD 5 as a whole – comprising California, Arizona, Nevada, Oregon, Washington, Hawaii and Alaska – exported an average of 350 kbd of refined products to other countries,[19] 12% of its total of 2,840 kbd.[20] California accounts for 65% of PADD 5's refining capacity.[21]

LOW CARBON FUEL STANDARD

California's Low Carbon Fuel Standard (LCFS) requires refiners to reduce the life-cycle (well-to-wheel) carbon intensity of their fuels by 10% between 2010 and 2020. It is a market-based, cap-and-trade scheme, which allows refiners that reduce carbon intensity by more than required to sell credits to those that underperform.

We work on the assumption that the LCFS in California, as it stands today, will not significantly constrain demand for tar sands feedstock at Californian refineries. The regulation allows for blending with lower carbon fuels to balance higher ones out, and the way the standards have been set, tar sands crudes are unlikely to be screened out. Thus Greg Stringham of the Canadian Association of Petroleum Producers (CAPP) has expressed his support for the LCFS: 'We are supportive of making sure there is no discrimination and as we've seen now in the iterations of the LCFS, they have got to the point where they don't have discrimination of Canada versus their own California crude, even though it may be heavier.'[22]

A further loophole is that the LCFS does not apply to refined product exports; it governs only fuels consumed within California.[23]

CALIFORNIA SUPPLY

Historically, refinery demand in California was met by Californian and Alaskan oil production (California receives about a third of Alaska's production). Since those two have declined, foreign imports have filled the gap.

The largest source of imports is the Middle East, primarily Saudi Arabia and Iraq.

Table 4.1: Capacity of California Refineries / kbd Source: Energy Information Administration (2015d)

	Number of refineries	Total refinery capacity	Heavy oil capacity
SF Bay Area	5	833	423
Santa Maria	1	10	0
Bakersfield	3	41	0
Los Angeles area	9	1,104	680
TOTAL	18	1,987	1,103

19 EIA 2015j
20 EIA 2015k
21 AFPM 2014
22 Hislop 2014
23 Swift 2015

Chart 4.1: California Crude Supplies Source: California Energy Commission (2015)

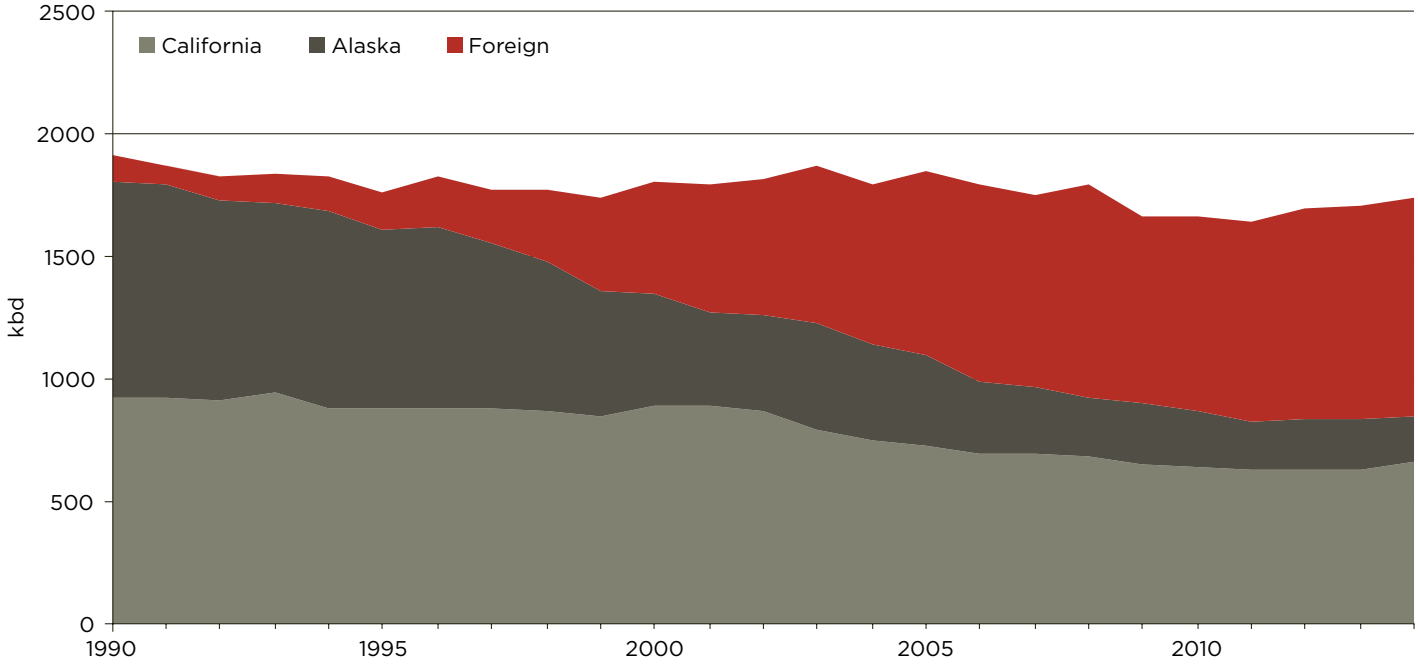


Chart 4.2: California Crude Supply, 2014 Source: Energy Information Administration (2015c); California Energy Commission (2015)

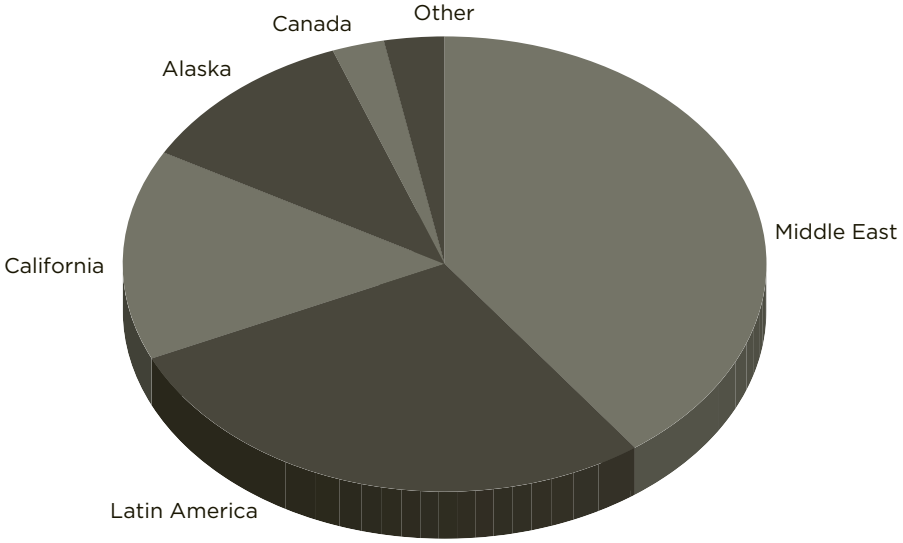


Table 4.2: California Imports by Type, 2014 / kbd Source: Energy Information Administration (2015c)

	Heavy	Medium	Light	TOTAL
Canada	35	3	5	43
Middle East	206	1	39	246
Latin America	28	78	359	465
Other	30	7	13	50
TOTAL	300	89	416	805

POTENTIAL CALIFORNIAN DEMAND FOR CRUDE FROM PNW TERMINALS

All but three of California's refineries are located on the coast, and are capable of receiving crude inputs by tanker or barge. The potential Californian market for new oil via the PNW rail terminals comes from three areas: offsetting declines in Alaskan oil production, offsetting declines in Californian production (much of it heavy oil), and displacing shipborne imports from outside North America.

Clearly, the potential market is substantial, if it can be accessed economically.

Chart 4.3: California Oil Production and Forecast Source: Rystad UCube

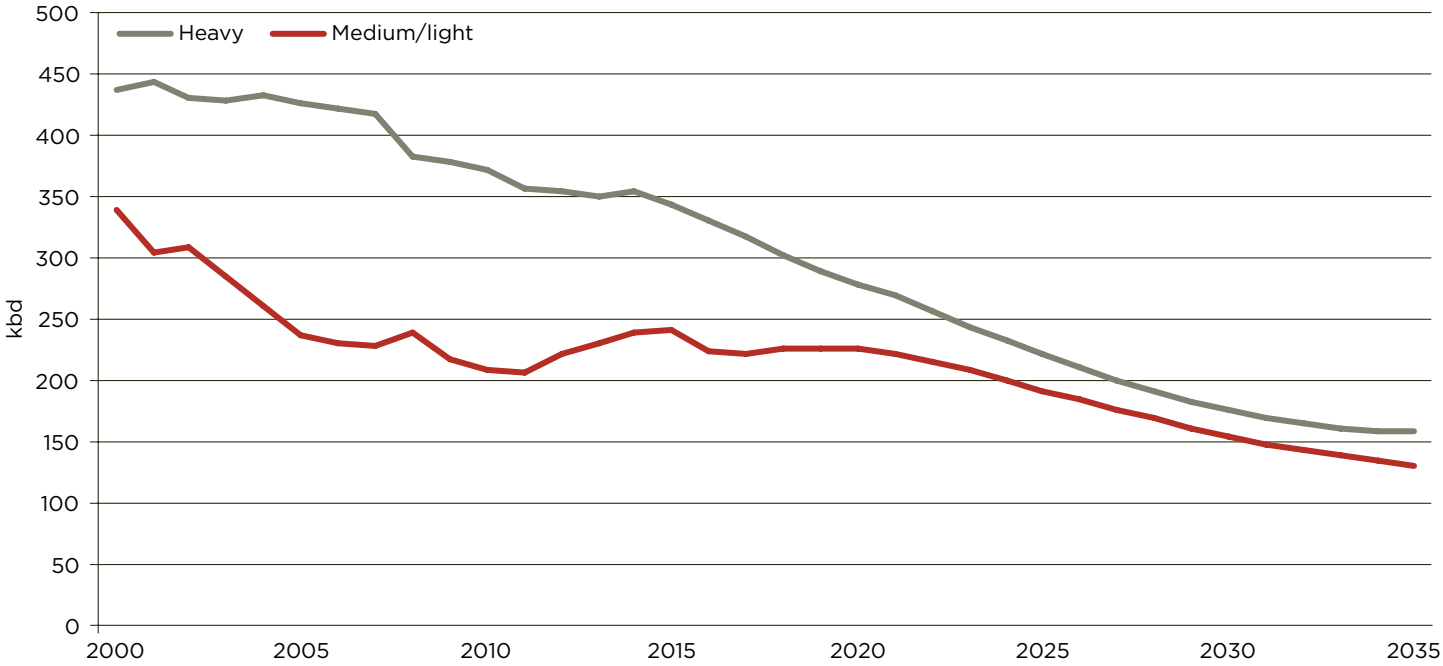


Table 4.3: Potential Market for New Crude in California, 2020 / kbd

	Heavy	Medium	Light
Offset Alaska reductions	35	0	0
Offset California reductions	65	15	0
Displace non-Canadian imports	265	86	411
TOTAL	365	101	411

Table 4.4: Potential Market for New Crude in Alaska, 2020 / kbd

	Heavy	Medium	Light
Offset Alaska reductions	0	0	25

ALASKA OIL MARKET

Alaska has five refineries, with total capacity of 165 kbd, none of them with cokers.[24]

They are supplied almost entirely from Alaska: in 2014, there were just three deliveries from Russia, each of 450-500 kb.[25] It is likely that these refineries will be priority destinations for Alaskan crude, hence no significant market for new oil supplies.

An exception is that one of the operators, Tesoro, plans to send up to 25 kbd of Bakken crude to its refinery in Kenai, AK, via its proposed terminal in Vancouver, WA.[26] This is because the refinery was originally built to process the lighter Cook Inlet oil, which is also declining, and is not optimally replaced by Alaskan North Slope oil.

HAWAII OIL MARKET

Hawaii has two refineries, with total capacity of 148 kbd, neither with cokers.[27]

The majority of Hawaii's crude comes from imports. In 2014, Hawaii imported 74 kbd, and in 2013, 88 kbd. The largest suppliers were Indonesia, Argentina, Vietnam and Thailand.[28]

Little oil comes from U.S. sources.[29] This is because of the Jones Act of 1920, which requires that any cargo shipped between two U.S. ports must be carried on vessels built in the United States, crewed by U.S. citizens and at least 75% owned by U.S. citizens. In consequence, shipping rates are significantly higher, and therefore U.S. crude sources cannot compete with imports.

We do not consider Hawaii further in this study, as we assume that the long shipping distance on expensive Jones Act vessels will not give favorable netbacks.

24 EIA 2015d
25 EIA 2015c
26 Tesoro 2014
27 EIA 2015d
28 EIA 2015c
29 ICF International 2013, pp.19-20; EIA 2015l

5. EXPORT TO ASIA?

We also consider whether oil from these terminals – either Canadian oil, or U.S. oil if the export ban is lifted – could be shipped to Asia (although terminal operators have not stated this as their intention).

Certainly there is significant market demand in Asia, including for Canadian heavy oil[30] – and this is the rationale for the proposed Northern Gateway and Trans Mountain Expansion pipelines to the British Columbia coast.

IMPACT OF VESSEL SIZE

However, unlike the marine terminals in BC, the U.S. PNW marine terminals are not deep enough to accommodate the largest tanker ships, such as VLCCs or Suezmax.

The costs of long-distance ocean transport vary significantly with size of tanker. Actual rates are published only for regularly used routes, and these generally use the same class of tanker (the largest the origin and destination ports will accommodate); however, we can make a rough estimate, as shown in table 5.2. While the two larger categories of vessel would not be permitted in Puget Sound, their estimated costs are included to indicate competitive costs were deeper terminals to be built in BC.

In short, deep-water ports in BC, if pipelines or new rail terminals were built, would be more suited than those in Washington and Oregon to export to Asia.

We assess the economics in subsequent sections of the report.

Table 5.1 Classes of Tanker Capable by PNW Terminals Source: Washington Deptartment of Ecology (2015 pp.270, 312, 327)

Location	Terminals	Maximum ship draft	Maximum ship class
Puget Sound	Cherry Point, Ferndale, Anacortes (2), Tacoma (2)	Regulatory limit to 125,000 DWT	Aframax
Columbia River	Port of Vancouver (2), Clatskanie, Longview	43 ft	Panamax
Grays Harbor	Hoquiam (3)	40 ft	Panamax
Willamette River	Portland	40 ft	Coaster

Table 5.2: Hypothetical Cost of Shipping Dilbit from Puget Sound to Shanghai, In Four Typical Tanker Sizes[31] Source: Oil Change International estimates (see Appendix 1)

Deadweight Tonnage (DWT)	Class	Draft	Capacity / kb	Per-barrel cost
70,000	Panamax	41 ft	470	$3.10
105,000	Aframax	46 ft	710	$2.40
150,000	Suezmax	52 ft	1,010	$2.20
300,000	VLCC	66 ft	2,020	$1.60

30 Kelly 2013; Moore et al 2011; Muse Stancil 2012; NEB 2013; Wood Mackenzie 2011

31 The distance from Puget Sound to Shanghai is roughly 5,000 nautical miles. At an average of 12 knots, the journey would take 17 days. With two days of docking and loading/unloading at either end, this would give a cycle time of 38 days, with 34 days of fuel use. Assume the vessel carries 20 days' fuel. Dilbit density 926 kg/m^3, synthetic 864 kg/m^3. See Appendix 1.

LOGISTICAL CAPACITY

In judging the possibility of export to Asia, the other factor to consider (along with economics) is logistics.

The key logistical factor is the quantity of storage at the terminal. Since it takes six or seven unit trains to fill an average Panamax tanker, crude must be unloaded over several days into large storage tanks, while the operator schedules tankers to arrive when sufficient crude to fill them has been collected. The tanks need to hold significantly more than will actually be loaded onto a tanker: whereas pipeline flows are generally predictable, rail deliveries are often disrupted due to causes including weather, rail congestion or mechanical problems. Any delay is compounded at the terminal itself, where a late train can keep the following one waiting until it has finished unloading. Tanker vessels too may arrive earlier or later than scheduled. Storage is the key to managing this variability.

How much extra storage is required to create this slack in the system? The answer will vary from company to company, according to how much they can drive efficiencies and how much risk of disruptions they are willing to accept. However, we can consider this indicatively. During the first six months of 2015, the Tesoro terminal in Anacortes had a mean utilization rate of 76%, with an interquartile range from 53% to 93%.[32] If an export-oriented terminal operator wanted to have sufficient storage to cope with this range, an extra 75% storage would be required (=93/53), above the volume required to fill the tanker. So, for a 450 kb Panamax, 790 kb of storage would be needed.

An alternative way of building slack into the system would be to operate at a lower utilization rate: where gaps between deliveries are greater, there is less risk of one delay disrupting the next delivery. Lower utilization rates would of course mean lower returns too. Again, this will rest on a company's strategy.

For the refinery-based terminals, exports would be very unlikely, except when the corresponding refinery is down for maintenance. The larger, merchant (non-refinery) proposed terminals have storage capacity as shown in Table 5.3.

Tesoro-Savage's proposed terminal has sufficient logistical capacity for exports. The company states on its website that 'we currently don't anticipate that crude oil handled at the facility will be exported', but notes that the decision will in fact be made by the companies shipping the oil.[35]

For the others, capacity may be borderline, and depends on a company's approach and judgment. At the lower end of the storage range, logistics would probably be too tight for 450 kb Panamaxes, but might possibly do smaller ones, at the expense of higher per-barrel shipping costs.

Table 5.3: Storage Capacity of Merchant Terminals Sources: Tesoro-Savage (2013b, p.2-104); Oregon Department of Environmental Quality (2014, pp.4-5); Westway (2015, pp.2-3, 2-8); Imperium (2015, pp.2-4, 2-9); Washington Department of Ecology (2014, p.1)

Terminal	Unloading capacity / kbd	Storage capacity / kb
Tesoro-Savage, Vancouver	360	2,160
Global Partners, Clatskanie	120	610
Imperium, Hoquiam	82	720 (+380)[33]
Westway, Hoquiam	49	1,000 (+324)[34]
Grays Harbor Rail Terminal, Hoquiam	50	800-1,000

Table 5.4: Cost of Shipping Dilbit from Puget Sound to Shanghai, in Small and Medium Panamax Source: Oil Change International estimates (see Appendix 1)

DWT	Capacity / kb	Per-barrel cost
55,000	350	$3.71
70,000	470	$3.10

32 Genscape 2015
33 The additional 380 kb of storage is intended for biofuels, but could be cleaned and repurposed for crude.
34 The additional 324 kb of storage is intended for methanol, but could be cleaned and repurposed for crude.
35 Vancouver Energy 2015

6. NETBACK ANALYSIS

In this section we assess the attractiveness of different transport routes – combining the effect of market opportunities and the cost of getting there – through the netback prices received by producers.

This means the amount they actually receive for their oil at the local distribution hub,[36] and when compared with production costs will allow us to assess production profitability. Netback price is assessed by estimating the price for which a physical sale is made (Appendix 2), minus the cost of transporting it to the place of sale (Appendix 1).

Generally, any producer will ship its oil to the location where it can get the highest netback.

The three charts 6.1 to 6.3 – for diluted bitumen (dilbit), synthetic crude and Bakken light oil – show our estimate of how netback prices vary among six different transport routes, two to the U.S. Gulf Coast (by pipeline or rail), one to a refinery terminal in Puget Sound, and three to rail-to-barge terminals in Grays Harbor or Columbia River followed by barge onto Puget Sound, barge to California (San Francisco) or tanker to China. Note that the China netbacks assume a 70,000 DWT (deadweight tonnage) Panamax. If logistical constraints limited export to a 55,000 DWT Panamax, this would deduct $0.60/bbl from the netback (Table 5.4).

Since they depend on crude price differentials, netbacks actually vary from day to day, and from month to month. We consider here a likely average over the course of a year, based on the calculations in Appendix 2. Reflecting the different timescales of the three types of oil production, we show netbacks for different sample years: 2025 for dilbit, 2030 for synthetic and 2020 for Bakken.

Types of oil in this analysis

Dilbit: tar sands bitumen that has been diluted with condensate or light oil, in order to make it flow. We assume 72-28 proportions of bitumen to diluent.

Synthetic crude: a light oil made by upgrading (partially refining) tar sands bitumen near the extraction site.

Bakken: a light oil extracted from the Bakken shale of North Dakota, using hydraulic fracturing (fracking).

36 Edmonton or Hardisty, in the case of the tar sands

Chart 6.1: Netback Prices for Dilbit (2025)[37] Source: Oil Change International analysis (see Appendices 1, 2)

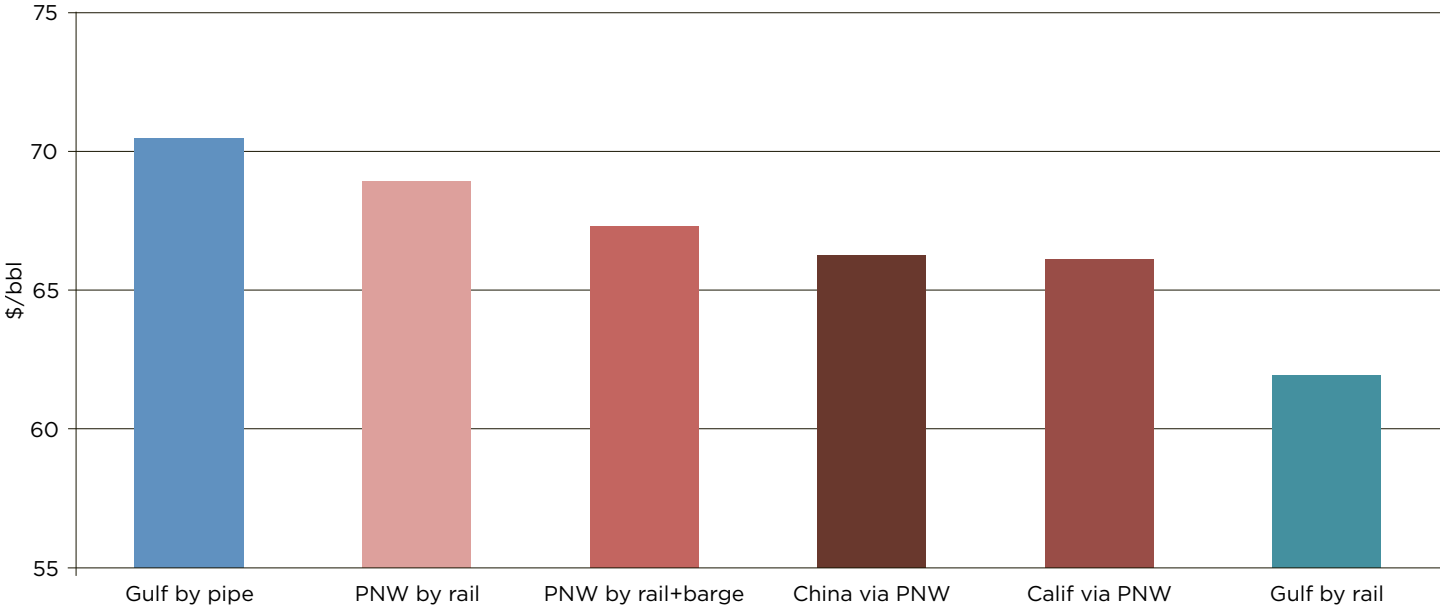
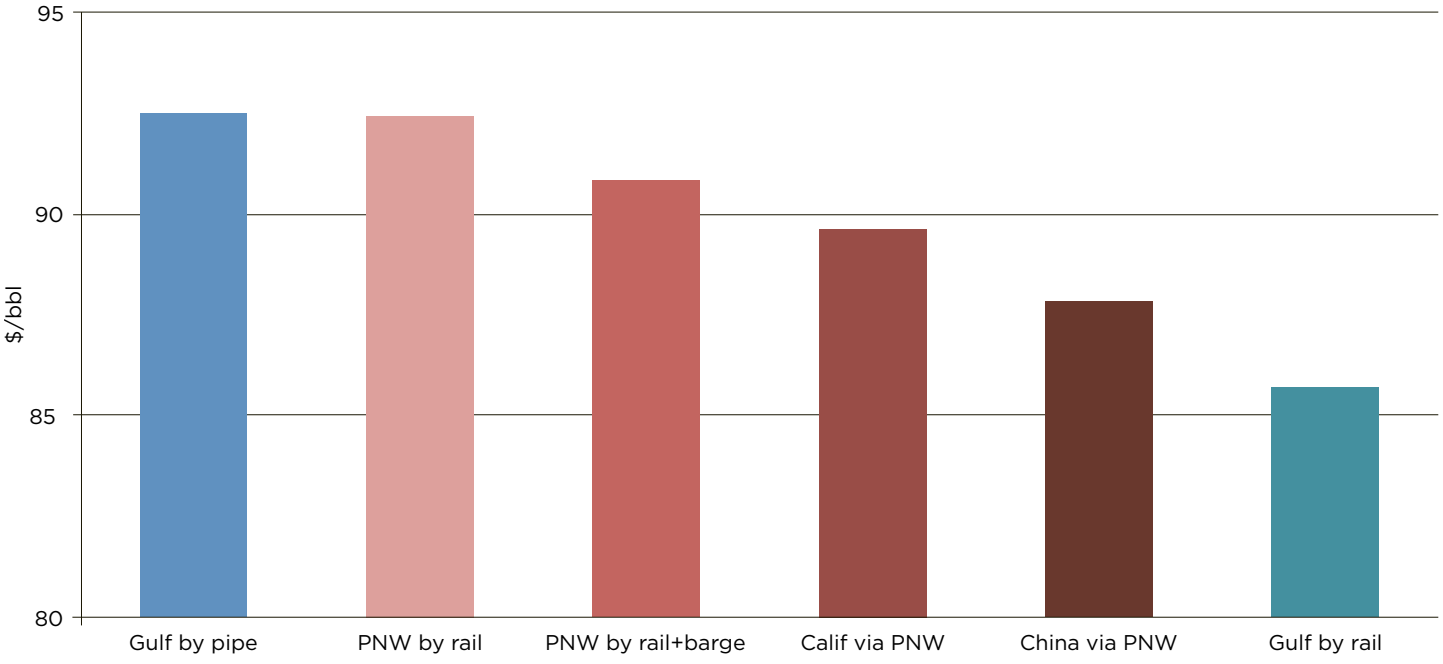


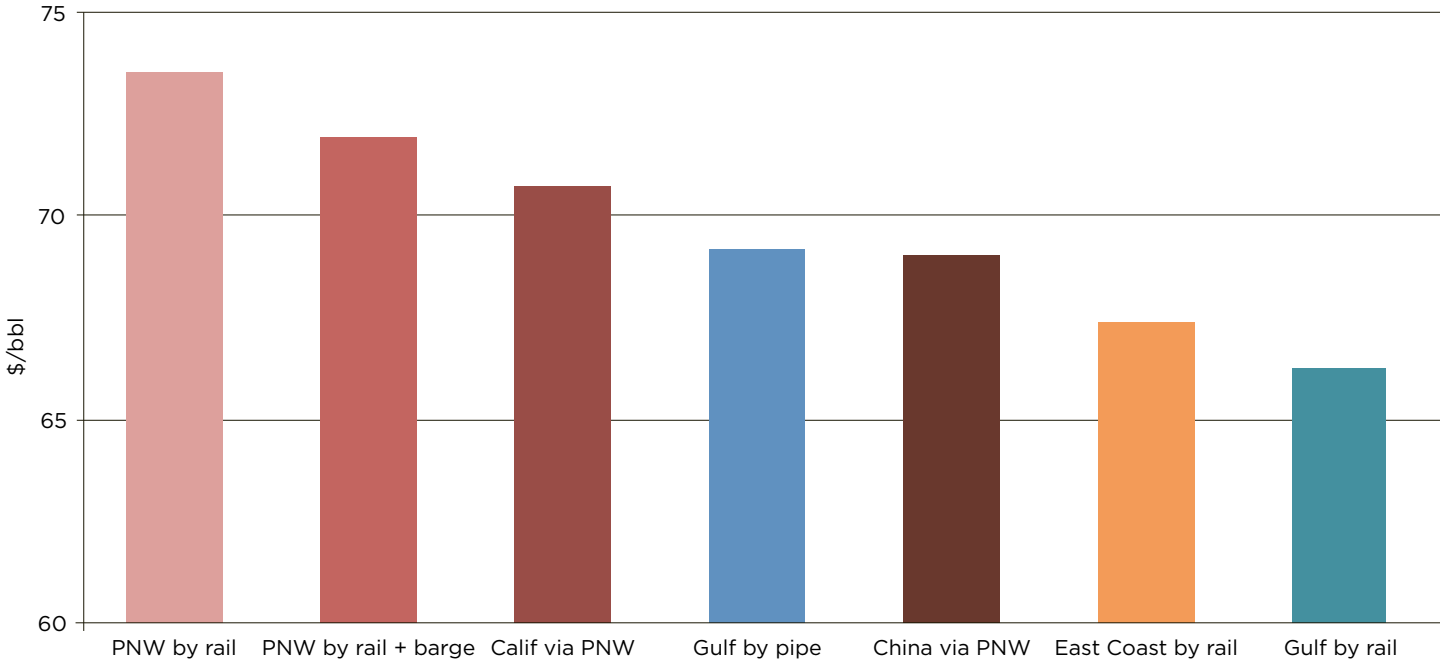
Chart 6.2: Netback Prices for Synthetic Crude (2030)[38] Source: Oil Change International analysis (see Appendices 1, 2)



37 Note: this is the netback price for a barrel of dilbit – the producer will receive less than this per barrel of bitumen, due to diluent costs. The transport cost is taken to be $10.50 for pipeline (IHS Energy 2014, p.12).

38 Transport costs from Canada to the Gulf are just slightly different due to being light oil: we estimate pipeline cost of $10/bbl.

Chart 6.3: Netback Price Received for Bakken Shipped to Different Markets (2020) Source: Oil Change International analysis (see Appendices 1, 2)



For both dilbit and synthetic, railing direct to a refinery in Puget Sound delivers a netback almost as high as piping to the Gulf. The netback becomes slightly lower if the oil has to also be barged to the refinery. Dilbit generates just slightly lower netbacks from export to China, whereas in the case of synthetic, sending it on from the PNW to California or China lowers the netback by up to $3/bbl. In both cases, railing to the Gulf delivers the lowest netback prices.

The reason for the attractiveness of PNW rail is that the transport cost is lower than other rail options – and only slightly greater even than pipelines to the Gulf – while sales prices are higher. This in turn is because traditional West Coast supplies (Alaska and California) are declining, whereas Gulf Coast supplies are increasing.[39]

For the Bakken, we see that netbacks for railing to the PNW are significantly better than any other route, and even sending the crude on by barge to California generates better netbacks than a pipeline to the Gulf.

We consider netbacks for Bakken exported to Asia – in the scenario that the crude export ban is lifted. These are lower than the other PNW options. They cannot directly be compared with Gulf netbacks, as the lifting of the ban would likely raise prices in the Gulf. However, lifting of the ban would be likely to also have less direct effects, such as providing temporary arbitrage opportunities, and making tar sands export logistically easier (due to less need to verify that cross-contamination has not occurred, and allowing the possibility of using U.S. crude as diluent).

See Appendix 3 for a discussion of how these results may vary if circumstances change.

39 To illustrate, Alaska North Slope in California has traded at an average premium of +1% compared to Louisiana Light Sweet in the Gulf, despite being heavier (30.0 vs 37.7) and higher-sulfur (1.1% vs 0.3%) (Bloomberg Professional; Fielden 2013a & 2015b).

7. VOLUMES SHIPPED TO AND THROUGH THE PACIFIC

In subsequent sections, we will assess how much new oil production could be unlocked by the PNW rail terminals, compared to what would be produced without them – in order to assess their impact on climate change.

Residents of Washington and Oregon however, will be at least concerned about the number of trains coming near their homes, and any increases in shipping along the coast. In this section, we estimate the total volume of oil that would be transported to the terminals, some of which might just be substituted from elsewhere (and therefore not add to the world's pool of carbon).

The key to this analysis is the netback prices calculated in Section 6. In general, a producer will ship oil to wherever it can obtain the highest netback. Once the demand in that destination is met, or the capacity to transport oil there is exhausted, other producers will send their oil to the market that gives the second-highest netback, up to volume limits, and then the third. This continues until all of the produced volumes have been allocated to a market.

In reality, it will not be quite as neat as this (see Appendix 3). Rail costs can vary by $1.50/bbl to $3.50/bbl – a difference exceeding some of the differences between netbacks arising from different export routes. What this implies is that there will in fact be overlaps between the different market options, rather than oil going to the second-highest-netback destination only after all of the first's capacity has been exhausted. Our estimates should therefore be treated as averages.

CAPACITY OF RAIL TERMINALS

During the first six months of 2015, Tesoro's Anacortes terminal unloaded an average of 38 kbd, out of 50 kbd capacity – a utilization rate of 76%. This is significantly higher than the 57% (120 out of 210 kbd) achieved over the same period by the PES terminal at Philadelphia, one of the busiest on the East Coast.[40] Anacortes probably performed better than Philadelphia for two reasons: higher netbacks and less track congestion.

Terminals are not likely to achieve significantly higher utilization rates than 75%, because the logistics of unloading trains in succession are inevitably less smooth than pipelines, and trains are often delayed by weather, mechanical problems or track constraint.

We now assess whether the terminals are likely to reach this logistical maximum. The actual flows will be determined by the lowest out of potential supply, unloading capacity and potential demand – whichever is the bottleneck in the system.

TAR SANDS VOLUMES

For tar sands, we saw in Section 6 that pipelines to the Gulf Coast will obtain the highest netbacks of the destinations considered,[41] followed by rail to the PNW, followed by rail to the Gulf.[42] Therefore, we infer that tar sands will be railed to the PNW only after the pipelines are full.

All proposed new pipelines and pipeline expansions out of Alberta are facing major political and public opposition, and legal challenges,[43] creating a significant likelihood that no new pipelines will be built.

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40 Genscape 2015

41 In fact, shorter pipeline routes to the Midwest, the Rockies or British Columbia will obtain even higher netbacks than the Gulf – we do not consider those here, because we assume oil already going there will continue to do so; we are interested in the additional barrels.

42 We did not estimate the netbacks for railing tar sands to the East Coast, as they will be lower than for the Gulf Coast: costs will be the same or higher, sales prices lower, and coker capacity limited.

43 All four major proposed new pipelines – Keystone XL, Northern Gateway, Trans Mountain Expansion and Energy East – are facing major opposition. TransCanada's proposed Keystone XL pipeline, from Hardisty to Cushing, has been delayed for more than five years, and President Obama has committed not to approve its construction if it adds to greenhouse gas emissions. Two proposed pipelines from Alberta to the British Columbia coast – Enbridge's Northern Gateway and Kinder Morgan's Trans Mountain twinning – both face legal challenges and extensive and growing public and political opposition, in particular from First Nations communities. TransCanada's proposed Energy East pipeline to New Brunswick has been delayed to at least 2020, and faces similar levels of opposition, especially in Quebec, through which it would have to pass. And expansions of the existing Enbridge pipeline system through the U.S. Midwest are now also subject to legal challenges and public protest.

According to research by Oil Change International,[44] the tar sands export system is almost full. Our Integrated North American Pipeline model (INAP)[45] finds that, if no new pipelines are built, completion of under-construction tar sands projects would take Canadian crude production beyond available refinery and pipeline capacity by around 375 kbd by 2020 (assuming 95% utilization rates[46]). This excess production would potentially be carried by rail to the PNW.

The potential demand for new heavy oil (dilbit) in Washington and California is about 440 kbd, and for new medium oil (synthetic) is about 115 kbd (Sections 3 and 4). Thus the additional potential supplies would not exhaust the demand, and none would be left to be railed to the Gulf.

Our estimate of potential tar sands supply to the PNW is therefore 375 kbd in 2020, assuming no new pipelines. This is just from existing and under-construction tar sands projects. If new projects are developed (Section 8), they could provide additional throughput in the early 2020s.

BAKKEN VOLUMES

Bakken crude will obtain the best netbacks from the nearest refineries: in North Dakota itself, the Midwest and the Rockies. These are accessed by existing pipelines, so as with tar sands, we assume existing pipelines will continue to be used at their current rate.

The North Dakota Pipeline Authority forecasts 2020 production at 1,200 or 1,600 kbd in its two scenarios (see chart 9.3 on p.35). This would be distributed as follows, in order of highest netbacks:

- Refineries in North Dakota: 70 kbd;
- Existing pipelines: 600 kbd (Section 9);
- Washington refineries;
- California refineries;
- Sandpiper pipeline (if built): 200 kbd (at 90% utilization, mostly to Eastern Canada);
- Dakota Access pipeline (if built): 405 kbd (at 90% utilization, mostly to the Gulf Coast);
- Asia via PNW rail terminals;
- U.S. East Coast by rail.

While the two proposed pipelines would offer lower average netbacks than rail to the PNW, they will be subject to take-or-pay contracts. If a producer opts for the security of a committed pipeline, the rail option is removed. Thus the potential Bakken supply to the PNW is between 0 (low production scenario, and Sandpiper and Dakota Access both built) and 930 kbd (high scenario; pipelines not built).

What about demand? The potential light oil demand is 13 kbd in Washington, 25 kbd in Alaska and 411 kbd in California. This is the limiting factor in the high-production, no-pipeline scenario.

Hence the potential Bakken volumes transported to the PNW terminals in 2020, subject to midstream constraints, would be between 0 and 450 kbd, depending on whether the pipelines are built and on Bakken production levels (specifically, how they respond to the price environment – see Section 9).

TOTAL VOLUMES

We now turn to the logistical limit of how much could be unloaded. This potential supply and demand of tar sands and Bakken crude applies to the PNW terminals as a whole, not just the new ones. The limiting factor here is:

- Existing capacity of 283 kbd, if operated at 75%, could unload 212 kbd;
- Proposed new capacity of 727 kbd, if operated at 75%, could unload 545 kbd.

The combined unloading would be 757 kbd, slightly below the combined upper-end estimate of 375 kbd of potential tar sands (from existing and under-construction projects) and 425 kbd of Bakken crude. This suggests that if no new pipelines are built, and/or Bakken production achieves the higher estimate, there may be future proposals for more PNW rail terminals, especially if new tar sands projects are developed (Section 8).

Based on this analysis of netbacks and potential volumes, we expect the PNW terminals to continue to achieve high utilization rates of around 75%.

An additional 545 kbd of crude-by-rail throughput would entail around eight additional unit trains per day.

Washington is already considered a 'refining state', with nearly half of its refined products leaving the state, mostly for Canada, Oregon or California (see p.14). On top of this, the majority of the additional crude unloaded at new rail terminals is intended to be transported onward – by barge or coastal tanker – to California, adding to oil shipping in the PNW's coastal waters, with its attendant risks. A maximum of around 100 kbd from the new terminals would be destined for the refineries in Puget Sound by 2020.[47] The remainder would add 430 kbd of shipping: between one and three extra vessels per day, primarily to California, and possibly also to Asia (Section 5).

44 McKinnon, Muttitt & Stockman 2015
45 INAP assesses the available capacity to export and refine Canadian crude. Unlike some other analyses, it looks not only at the pipelines directly leaving Alberta and Saskatchewan, but at the whole system of export infrastructure, and the pipelines and refineries connected to it. INAP calculates effective capacity by evaluating bottlenecks, from western Canada to the ultimate refinery or export tanker.
46 While the modelled capacity in INAP is based on actual operating capacities of each element rather than theoretical peak flow (i.e. it allows for maintenance and batching), no system can be run at 100% of its capacity, as that would imply perfect efficiency. In reality, therefore, the effective capacity will be less than the calculated.
47 Including barges from the southern terminals, which would displace vessels bringing crude from Alaska or from overseas

8. IMPACT ON TAR SANDS PRODUCTION

Having looked in the previous section at the volumes likely to be transported to the PNW, we now consider how much carbon could be unlocked that otherwise would have remained in the ground.

WILL PNW RAIL TERMINALS UNLOCK NEW TAR SANDS?

We noted in the previous section that there is no spare capacity in the pipeline system out of Alberta, so if no major new pipelines are built, any further expansion of the tar sands could be exported only by rail.

Tar sands projects are characterized by very long timescales, high up-front capital costs and steady production throughout a project lifetime. After an investment decision, a project may take five or more years to bring into production, but will then produce oil at a steady level for up to 40 years, and sometimes even longer. Once the capital costs have been sunk, it is generally in a producer's economic interest to continue producing regardless, as operating costs are comparatively low.

For this reason, we estimate the impact of the PNW rail terminals on tar sands production by modeling the investment decision for a set of sample projects, in alternate scenarios. The question is: which projects would likely go ahead if they can get the PNW netbacks, but would not go ahead if they can get only the lower netbacks available elsewhere.

One of the most important metrics for a company deciding whether to proceed with a new project is its Internal Rate of Return (IRR).[48] The threshold IRR required for approving a project is commonly around 10%, although it will vary from case to case, reflecting a company's appetite for risk, and strategic advantages such as getting established in a market.

We assume in this analysis that projects expected to deliver an IRR above 10.5% will be approved; those with an IRR below 9.5% will be rejected; and those with an expected IRR between 9.5% and 10.5% will be considered marginal, and may or may not go ahead, depending on the company.

Since future revenues are determined by the oil price at that time, the calculation of IRR depends on assumptions made about what will happen to oil prices. While no one can reliably predict the oil price, we use the forecast of the U.S. Energy Information Administration to approximate the base-case forecast used by companies when they make their investment decision.

HOW PROJECT ECONOMICS WOULD BE AFFECTED

We use Rystad Energy's UCube database for this analysis. Rystad - which is used widely by the industry and by financial analysts – provides economic data for all of the world's upstream oil and gas projects, based on a combination of company reports and Rystad's own modeling.

We look at the economics of market access using a cashflow model to assess the expected IRR for several typical projects, both bitumen (exported as dilbit) and synthetic crude, for six export routes: pipeline or rail to the Gulf, and four routes via the PNW rail terminals. The results are shown in Tables 8.1 and 8.2.

Rystad calculates a break-even oil price for each project.[49] This does not give a clear determination of a project's viability, but does give a useful rough indication, and we include this also in the table for comparison of projects.

48 IRR is a measure of a project's profitability, which takes into account the time at which expenditures and incomes occur, in order to allow for the 'time value of money' (the fact that a dollar today is worth more than a dollar in the future, because it can be invested and grown). IRR is technically defined as the discount rate at which the project's net present value (NPV) is reduced to zero.

49 Defined as the constant real oil price at which project NPV would be positive, at a 10% discount rate

Table 8.1: Profitability of Illustrative Undeveloped Projects Exported as Dilbit[50] Source: Oil Change International cashflow models
Color code: green = commercial; grey = marginal; red = uncommercial

Project	Rystad breakeven price	IRR					
		Gulf Coast by pipeline	Gulf Coast by rail	PNW by rail	PNW by rail + barge	Calif. by rail + barge	China by rail + Panamax
Christina Lake Phase 3B (MEG)	74-75	11.8%	9.2%	11.3%	10.7%	10.5%	10.7%
Foster Creek Phase J (Cenovus/Conoco)	76-77	12.1%	9.7%	11.7%	11.3%	10.9%	11.1%
Sunrise Phase 2A (BP/Husky)	88-89	10.6%	8.5%	10.3%	9.8%	9.5%	9.7%
Christina Lake Phase H (Cenovus/Conoco)	91-92	10.1%	8.7%	9.8%	9.6%	9.4%	9.5%
Birch Mountain Phase 1 (Canadian Natural Resources)	102-103	10.1%	8.3%	9.8%	9.4%	9.2%	9.5%

Table 8.2: Profitability of Illustrative Undeveloped Synthetic Crude Projects[51] Source: Oil Change International cashflow models
Color code: green = commercial; grey = marginal; red = uncommercial

Project	Rystad breakeven price	IRR					
		Gulf Coast by pipeline	Gulf Coast by rail	PNW by rail	PNW by rail + barge	Calif. by rail + barge	China by rail + Panamax
Syncrude Mildred Lake and Aurora Stage 3 Debottlenecking (Canadian Oil Sands /Imperial/others)	81-82	12.6%	11.6%	12.5%	12.3%	12.2%	11.9%
Jackpine Phase 1B (Shell/Chevron/Marathon)	83-84	12.1%	11.5%	12.1%	11.9%	11.7%	11.7%
Terre de Grace Phase 1 (BP/Value Creation)	89-90	10.7%	9.8%	10.6%	10.3%	10.1%	9.9%
Firebag Phase 5 (Suncor)	93-94	10.0%	9.2%	9.9%	9.7%	9.6%	9.4%
Muskeg River Mine Expansion and Debottlenecking (Shell/Chevron/Marathon)	95-96	10.3%	9.4%	10.2%	9.9%	9.8%	9.6%

50 The cashflow model uses production, capex and opex forecasts from Rystad UCube. Government take is calculated by the model, according to Alberta tar sands fiscal terms. Oil price forecasts are from EIA 2015a. CAD/USD exchange rate is assumed to be 1.05 and long-term borrowing rate 2.4%.
51 The methodology and assumptions are the same as for the dilbit table, except that there is no diluent cost.

We see from the table that:

- All five of the projects would be considered commercial or marginal if they had pipeline access to the Gulf. This is why companies are lobbying so hard for new pipelines such as Keystone XL;
- If neither new pipelines nor the PNW rail terminals were built, four of the projects would be considered uncommercial, and one very marginal;
- However, at the lower end of the breakeven price range, PNW rail terminals can make projects commercial that otherwise would not be;
- For projects with higher breakeven prices, PNW rail terminals could make them marginal, although some routes would be uncommercial.

In order to translate these sample findings into the wider set of proposed tar sands projects, we will classify them by breakeven price. Interpreting the broad shape of these results, we infer that building of the PNW rail terminals could:

- Lift projects with breakeven price between $70 and $80 from uncommercial to commercial;
- Lift projects with breakeven price between $80 and $90 from uncommercial to marginal.

For synthetic crude, the picture is different. Again interpreting the general pattern of the table, we tentatively infer that:

- Projects with breakeven price below $90 would be considered commercial or marginal even with rail to the Gulf as the transport option: building of the PNW rail terminals would not significantly change the viability of these projects;
- The PNW rail terminals could lift projects with breakeven price between $90 and $100 from uncommercial to marginal.

Why do the synthetic projects give different results from bitumen (transported as dilbit) projects? One reason is that they are expected to start later[52] – which means that they capture more of the higher prices that occur later in the model (under EIA's forecast, prices consistently rise from current levels). Another factor is that the synthetic projects are generally larger, which means a small change in marginal costs has a smaller impact on overall project economics.

VOLUMES OF CARBON UNLOCKED

Noting again the simplifications inherent in Rystad's breakeven price, we use it to translate these results into a rough indicator of the volumes at stake, with the projects above as a guide.

The chart below shows Rystad's forecast of how much the new (post-2015) projects within each breakeven band would produce in 2030, if they went ahead (note that the projects with higher breakeven prices might not receive investment approval from the companies, especially if market access remains a problem, and/or the oil price stays low).

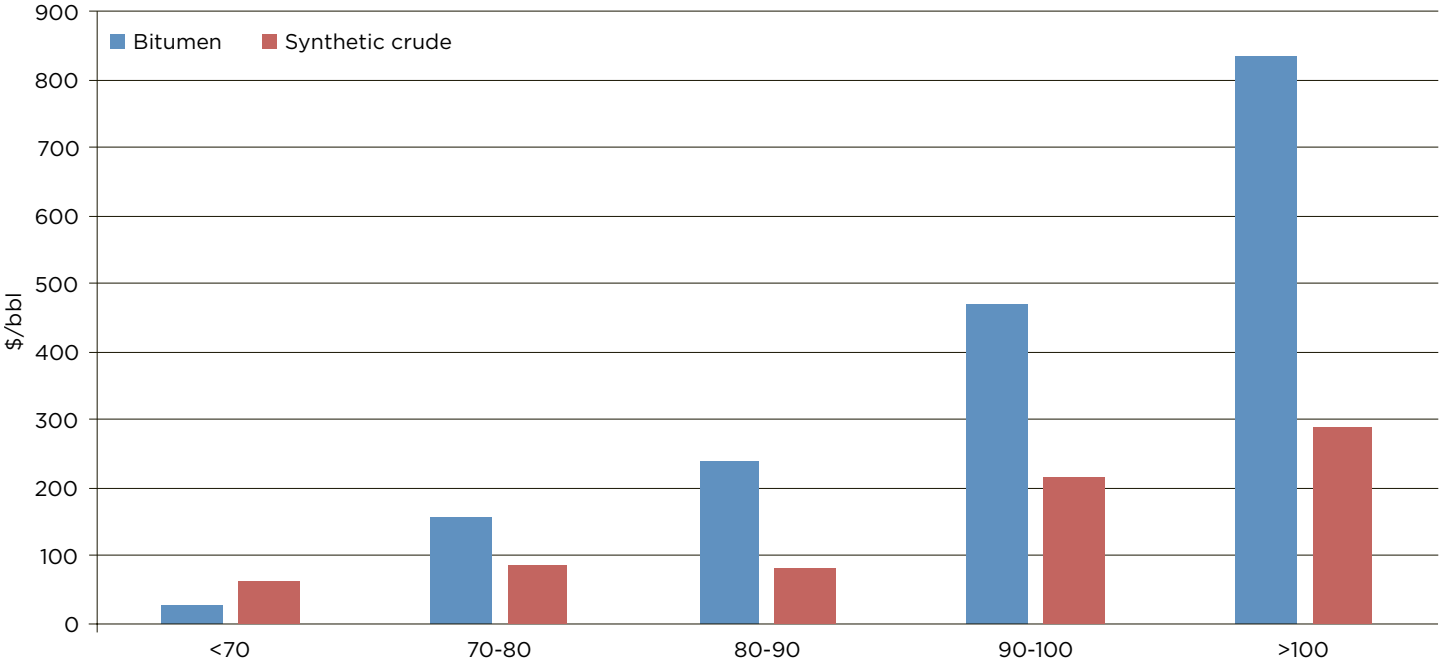
If our tentative observations above are correct, PNW rail terminals would lift from uncommercial to commercial:

- Bitumen projects with breakeven price between $70 and $80. The production volume unlocked (Chart 8.1) would be 154 kbd of bitumen in 2030. When diluted, this would be 214 kbd of dilbit.

They would lift from commercial to marginal:

- Bitumen projects with breakeven between $80 and $90, which would produce 239 kbd of bitumen in 2030, or 332 kbd of dilbit;
- Synthetic crude projects with breakeven between $90 and $100, which would produce 215 kbd in 2030.

Chart 8.1: Forecast Production From Potential New (Post-2015) Tar Sands Projects in 2030, by Breakeven Band Source: Rystad UCube (2015)



52 The synthetic projects are expected to achieve first production in 2024-26 for all except Firebag, compared to 2020-22 for the bitumen projects other than Birch Mountain.

We must also consider constraints in the transport infrastructure (Section 2), and the refinery capacity (Sections 3-4). The actual extra volume will be determined by the lowest of these – the bottleneck in the system.

We saw in Section 7 that all of the available PNW rail capacity could be taken by under-construction tar sands projects and by Bakken crude, if Bakken achieves the volumes forecast in the higher scenario and if no pipelines are built. In this scenario, Bakken volumes could compete with new tar sands for the available capacity. How would the competition for limited unloading capacity between tar sands and Bakken play out? It will depend on timing (when the production is available), and on deals done, but judging by the netback differences compared to the next best option, tar sands shippers would be able to pay higher tariffs and still gain an advantage. If they do, or if Bakken volumes are at the lower end of the possible range, the spare capacity of PNW terminals after existing tar sands would be 757 minus 375 = 382 kbd.[53]

As for refinery capacity, the combined Washington and California potential heavy oil demand in 2020 is 443 kbd, rising to 591 kbd by 2030 as Alaskan and California production declines further. On top of this is substantial potential Asian heavy oil demand, as dilbit exports to Asia could generate attractive netbacks. Asian exports are less attractive for synthetic crude. West Coast potential demand for medium oil is 114 kbd, though it may also be able to displace some light oil demand.

We conclude that the PNW terminals could unlock, in 2030:

- 154-275 kbd of new bitumen production; and/or
- 0-215 kbd of new synthetic crude production.

In the absence of pipelines, the PNW rail terminals could be the sole driver of growth in the tar sands.

INDUSTRY HOPES: RAILBIT, NEATBIT

For a few years, the oil industry has argued that crude-by-rail can be significantly cheaper if bitumen is transported in a less diluted form. Whereas pipelines require the bitumen to be diluted in order to flow, this is not the case for rail transport, where heated railcars can keep the bitumen in fluid state. To transport diluted bitumen adds cost not only for purchasing the diluent (much of which has to be imported into Alberta) but also for transporting its extra volume. Some advocates of crude-by-rail argue that it is the natural transportation mode for bitumen, because of its ability to avoid the 'diluent penalty'.[54]

However, to date only very small quantities of bitumen have been transported either in its near-pure form (neatbit) or with lower levels of dilution (railbit). The reason is that the largest crude-by-rail terminals are around Edmonton and Hardisty, about 300 miles to the south of the tar sands fields. Smaller terminals in the tar sands region itself can load manifest trains (a few oil cars among numerous other cargoes) but not unit trains (hauling only oil cars). Unit trains are significantly cheaper per barrel than manifest.

Bitumen is generally piped to Edmonton or Hardisty for loading onto trains or into trunk pipelines – and for that first stage of the journey it has to be diluted in order to flow. The only ways to get neatbit or railbit onto unit trains are either to truck it all the way to Edmonton, or to pipe it there and remove the diluent with a diluent recovery unit (DRU). The industry has been talking about building a DRU for rail loadings since at least 2012, and MEG, Gibson and Canexus/Cenovus have all expressed intentions to build one. None has yet been built, and the most advanced – MEG's – remains on hold.

In summary, however you do it – whether it's manifest rail or DRU processing or trucking – there are extra costs and logistical hurdles, and no one has yet proved the approach at significant scale.

53 Midstream capacity constraints would also come into play if the differences in netbacks – and hence in project IRR – between the four routes via PNW rail make a difference in approvals for the marginal projects. For example, the highest netbacks and IRRs are from transport directly to the refineries in Washington, for which the proposed new capacity is just 60 kbd (the Shell terminal at Anacortes).

54 E.g. Cairns 2012 & 2013; Vanderklippe 2013; IHS Energy 2014; Fischer 2014

9. IMPACT ON BAKKEN PRODUCTION

In this section, we conduct a similar analysis for production from the Bakken shale as we did for tar sands in the previous section: how much oil could be unlocked by the terminals that would otherwise have been left in the ground?

CURRENT DESTINATIONS FOR BAKKEN CRUDE

As the chart below shows, most of the rapid growth in Bakken oil production since 2010 has been transported by rail. Pipeline usage has mostly remained steady, but actually fell in absolute terms in 2013 when price differentials were at their widest: better netbacks could be obtained by railing, at higher cost, to the lucrative East Coast markets than by piping to the glutted Midwest or Gulf Coast. Over the last year, however, pipeline usage has increased, biting into rail usage, and is now above 600 kbd, out of capacity of 690 kbd.

The portion carried by rail has gone primarily to East Coast refineries (PADD 1). It earlier went to the Gulf Coast (PADD 3), but that has since declined following pipeline build-out. In 2014-15, around 150-200 kbd of Bakken crude has been railed to PADD 5. This is as would be expected: since that is where the highest netbacks can be obtained (Section 6), producers will send as much there as the infrastructure capacity will allow.

Chart 9.1: Transport of Bakken Crude Source: North Dakota Pipeline Authority (2014-15; Kringstad 2014, p.11)

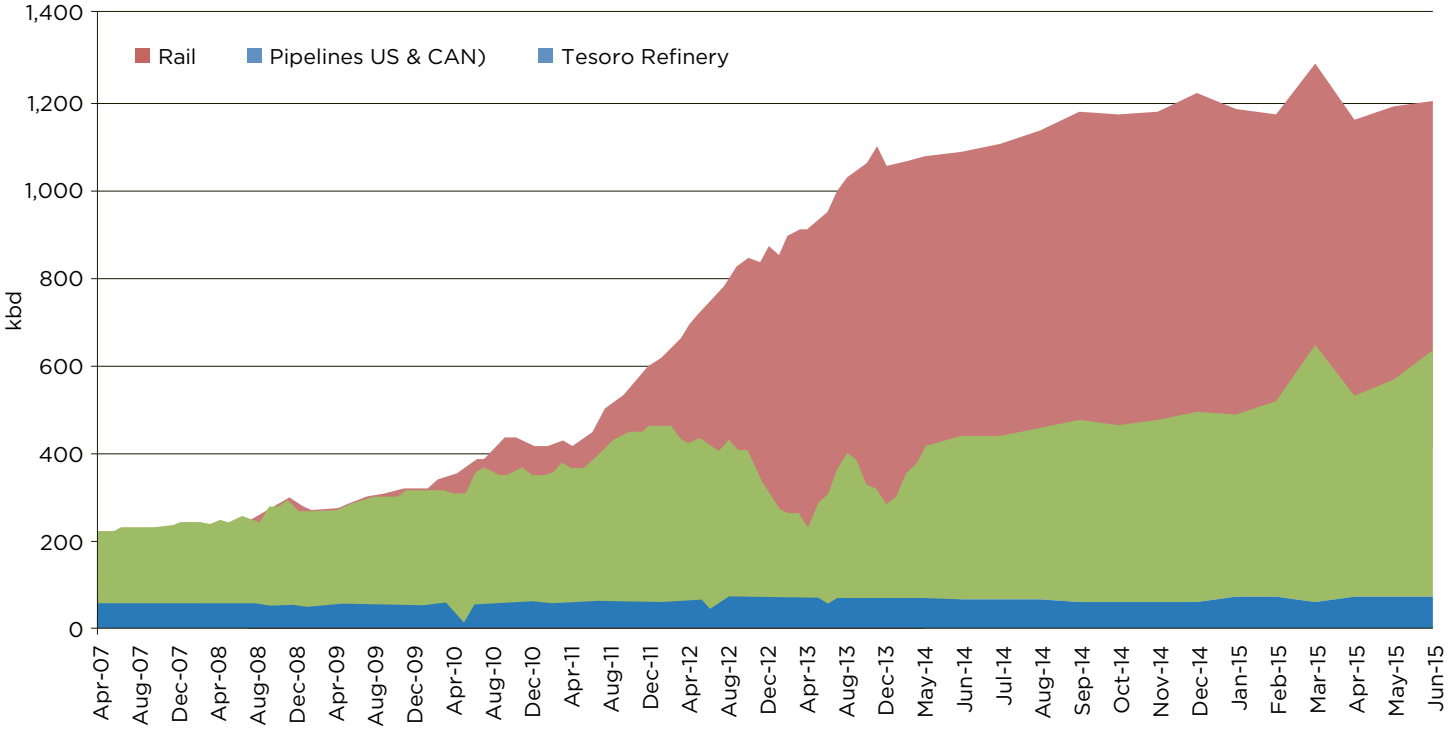


Chart 9.2 Rail Destinations of Bakken Crude Source: Energy Information Administration (2015f)

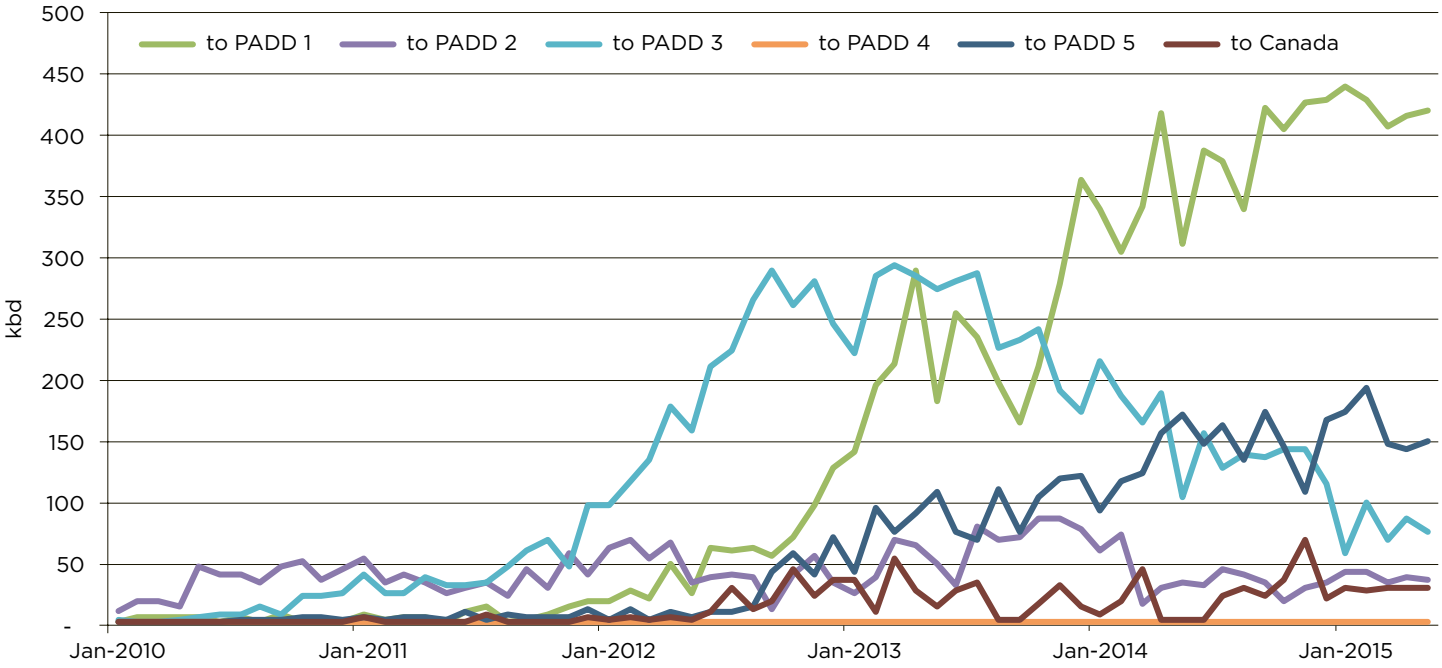


Table 9.1 Existing and Proposed Pipelines from the Bakken Source: company reports

Name	Company	Destination	Capacity	Status	Date expected
Existing pipelines:					
Butte (incl. twin)	True	Guernsey, WY	220	Existing	-
North Dakota System	Enbridge	Clearbrook, MN	210	Existing	-
		Canadian border	145	Existing	-
Double H	Kinder Morgan	Guernsey, WY	84	Existing	-
Bakken North	Plains	Canada	40	Existing	-
Proposed new pipelines:					
Dakota Access	Energy Transfer Partners	Patoka, IL	450	Applied for permit in January 2015. SD decision by mid-December	Late 2016
Sandpiper	Enbridge	Clearbrook, MN	225	MN approved certificate of need; decision on routing late 2015 / early 2016; likely legal challenges	2017
Upland	TransCanada	(Energy East pipeline)	220	Successful open season during 2014	2020

The pipelines go to the Rockies region (either to PADD 4 refineries, or on to Cushing, OK, via the Pony Express pipeline), to the Great Lakes region, or to Canada.

Proposed new pipelines would add 900 kbd of capacity. At that point, pipeline capacity would actually exceed Bakken production (Chart 9.3, below – note that this includes Keystone XL as a proposed future pipeline, unlike Table 9.1).

We did not conduct netback analysis for Bakken crude piped to the Midwest/ Great Lakes or to Canada – on grounds that baseline crude volumes will continue to travel there; we are interested in the additional barrels.

Our analysis tells us that PNW rail offers better netbacks than pipelines to the Gulf (which Dakota Access is, with an additional pipeline from Patoka, and some of the PADD 4 shipments will be, via the Pony Express pipeline to Cushing). We can thus expect that new pipelines might eat into rail shipments to the East Coast, pushing those refineries back to dependence on imports and/or barging from the Gulf, but not the PNW.

THE UNCERTAINTY IN BAKKEN ECONOMICS

Whereas a tar sands project relies heavily on a single investment decision, which will set the course for the coming decades, shale fracking is highly dynamic, with decisions made almost on a weekly basis about where and whether to drill. As a result, the economics are determined largely at the level of an individual well rather than a whole project. Meanwhile, production rates decline very quickly, often falling by 50-70% in the first year alone. Production is sustained by what has been called the drilling treadmill.

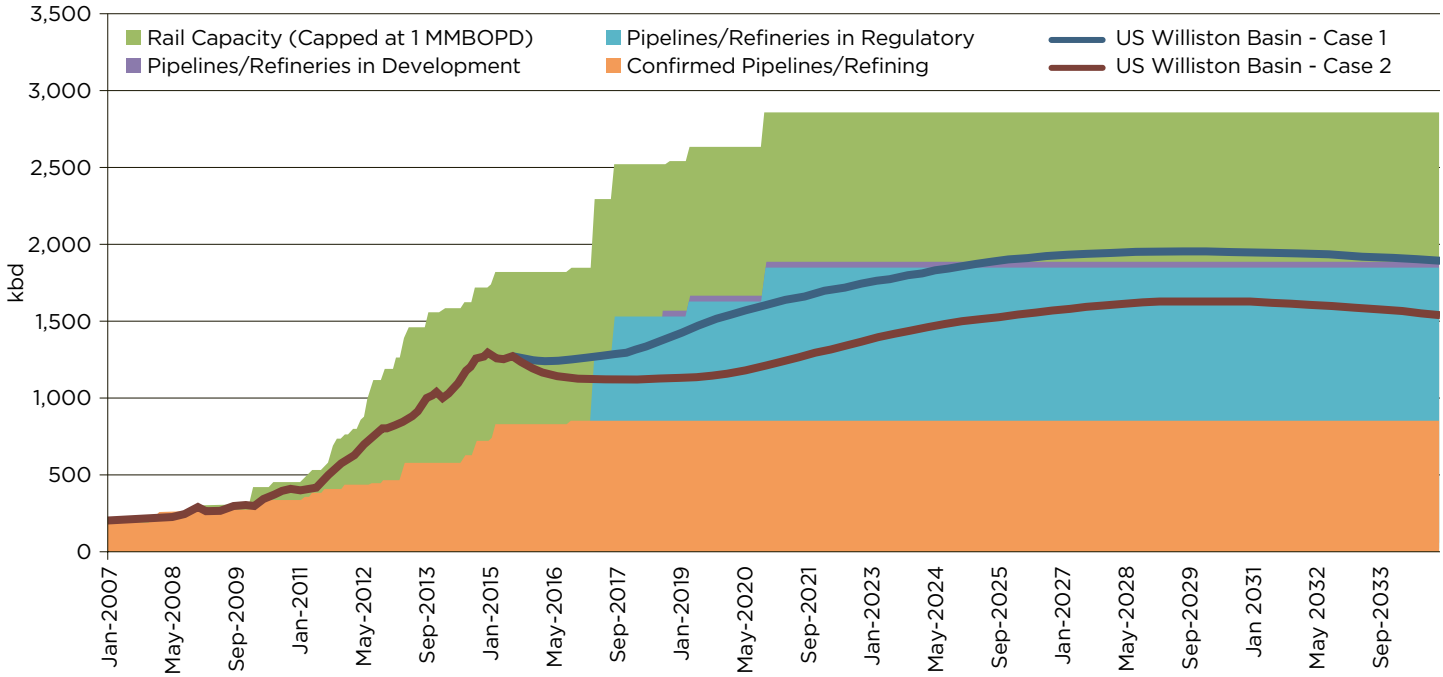
Since OPEC decided in November 2014 not to cut its oil production to shore up prices, the energy and financial press have been filled with analysis, discussion and speculation as to how lower prices would affect U.S. tight oil production. During the early months of 2015, some analysts obsessively watched the rig count in North Dakota, as an indicator of what might come next.

The rig count is a useful indicator of the future, though an imperfect one. One problem is that there are two time lags in the system:

- Producers are locked into contracts for the lease of drilling rigs, so cannot immediately idle them in response to prices;
- Wells do not begin production immediately after drilling: the well is first connected to pipelines, before a fracking crew comes to fracture the rock and start the oil flowing – this timing is determined both by availability of the crew/equipment and by the producer's judgment of economic conditions.

The impact of the first time lag is shown in Chart 9.4, which suggests that the average delay between price signal and rig count change (due to rig lease contracts) is about four months. This shows the price at Clearbrook, MN, which reflects the marginal netback[55] - likely for sales to East Coast refiners – plus the cost of transporting the oil from the wellhead to Clearbrook (generally estimated to be around $3/bbl).

Chart 9.3: Projected Bakken Production vs Export Capacity Source: North Dakota Pipeline Authority (Kringstad 2015, p.25)



55 The marginal netback is obtained where the next additional barrel would optimally be sold, i.e. the most favorable remaining destination after all production has been allocated in order of highest netbacks, up to the available demand or capacity in each market.

Chart 9.4 Bakken Price at Clearbrook (Bakken UHC) and Bakken Rig Count Sources: Bloomberg Professional; Energy Information Administration (2015g)

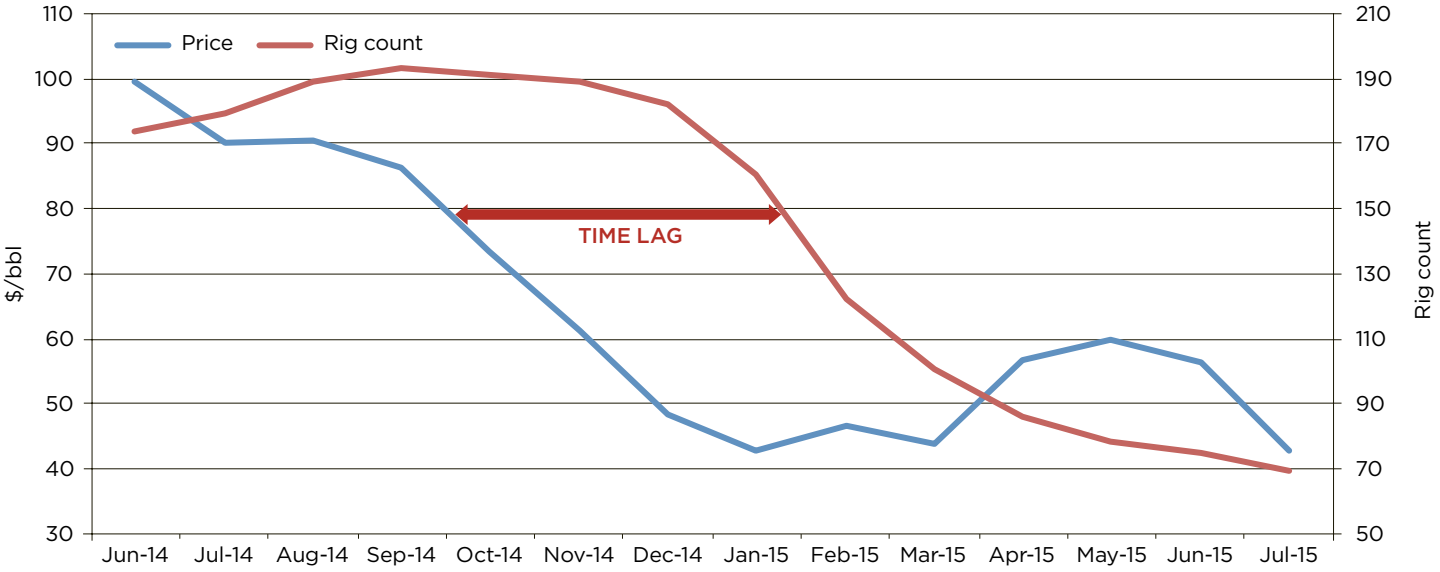
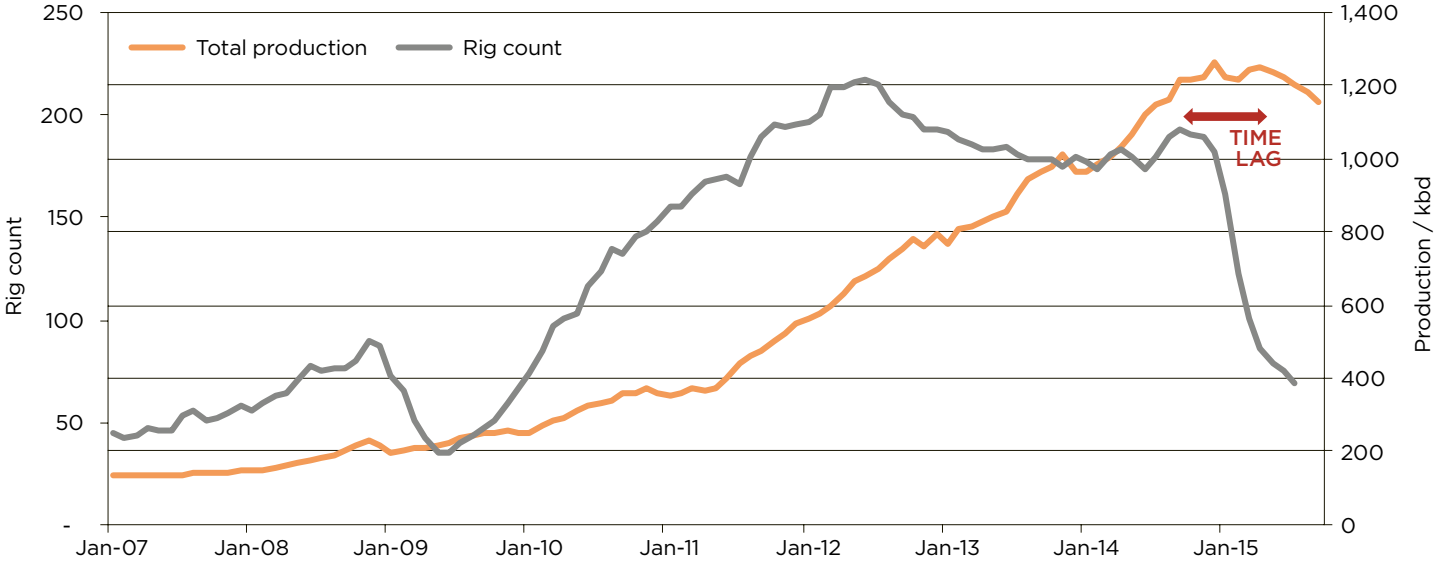


Chart 9.5: Bakken Rig Count and Production[57] Source: Energy Information Administration (2015g)



The rig count has now fallen dramatically, from nearly 200 before the crash to around 70 by July 2015, but actual oil production has only just started to decline (Chart 9.5). Recent analysis[56] by the North Dakota Pipeline Authority estimates the time lag between drilling a well and starting production from it, averaging 170-180 days in 2014.

Thus much of the new production in the first half of 2015 reflected drilling decisions made before the oil price fully collapsed, and even now the impact has not been fully factored in. What makes these time lags problematic for analysis is that much has changed in the meantime. Producers have reacted to lower prices by focusing drilling more closely on 'core areas' of the Bakken formation, which give higher production rates – yet we do not know how long the core areas can continue producing profitably.[58] And costs have been forced down: some companies have reduced costs by as much as 25% during the first half of 2015.[59] We do not know either whether they will be able to cut costs any further.

As a result of the above factors, analysts are widely divided on how lower prices will affect U.S. shale production. There are major caveats to any economic analysis of the Bakken.

56 Kringstad 2015, pp. 6-7, 10, 13-15
57 EIA 2015g
58 For a discussion, see e.g. Likvern 2015.
59 Kemp 2015a

HOW PROJECT ECONOMICS ARE AFFECTED BY NETBACK PRICES

Since the economics function at the well level rather than project level, and since drilling decisions are constantly made throughout the production, we cannot adopt the same approach as we did for tar sands.

In April 2015, the North Dakota Department of Mineral Resources (DMR) presented an estimate of how netback prices (for the marginal barrel) would affect the rig count. Basically, the lower revenues are for a producer, the less new drilling they will be able to afford.

Then, based on estimates of well productivity and decline rates, the DMR extended this to estimate how subsequent production would be affected. While the DMR may be in the best position to assess these economics, their estimate should be treated cautiously, for all the reasons above.

The DMR's analysis implies that a $10 reduction in netback would cause a fall in rig count of between 15 (if netbacks are around $60-$70) and 50 (if netbacks are $30-$40). This would lead to a fall in production, two years later, of between 100 kbd and 250 kbd.

However, based on what has happened since those estimates were made, it appears the DMR may have underestimated the impact of price on rig count. If the average time lag due to rig lease commitments is about four months, the July rig count would reflect the marginal netback received in March, which was slightly above $40/bbl (Chart 9.4). In fact, the July rig count was 69 rather than the forecast 90.[60]

A more recent analysis by consultants RBN Energy (2015, pp.11, 13) suggests an impact on production at the higher end of DMR's range, even at the higher price levels. RBN modelled two price scenarios: one where WTI rises fairly steadily from the current level of around $50 to $60 by 2021, and another where it rises to $80 by 2021. According to RBN's model, Bakken production in 2021 would be 1,100 kbd in the lower-price case, and 1,500 kbd for higher-price. In other words, a $20 change in price causes a 400 kbd difference in production.[61]

In our analysis, we assume that a $10 change in netback leads to a change in production levels of 250 kbd.

THE IMPACT OF THE PNW RAIL TERMINALS

The actual impact of the PNW rail terminals on Bakken netbacks is less than $10, so we assume that the above effect is proportional. In Table 9.3 we translate the relative netbacks versus alternative options into an impact on viability.[62] If the Dakota Access pipeline is built, the comparison is with Gulf pipeline netbacks. If neither Dakota Access nor Sandpiper are built, the comparison is with East Coast rail.

For the three destinations via PNW and two comparators, the impact of the terminals on netbacks is between $2 and $6. We assume that they could potentially impact production levels by between 50 kbd (= 2/10 x 250) and 150 kbd (= 6/10 x 250).

To find the true impact on the whole system, we need to also consider whether the bottleneck may be midstream or downstream. We saw in Section 7 that committed growth from under-construction tar sands, in the absence of new pipelines, could lead to up to 375 kbd being shipped to the PNW. Again assuming 75%, the terminals (existing and new) could unload 758 kbd. Thus the terminals could unload a further 383 kbd

Table 9.2: Impact of Netback Price on Drilling and Production Rates, North Dakota Source: ND Dept. of Mineral Resources (Ritter 2015, p.6)

Netback	Rigs	New wells	Jan 2016 production / kbd	Jan 2017 production / kbd	2-year production change / kbd
$30	40	1,100	800	700	-500
$40	90	2,400	875	720	-480
$50	120	3,200	1,050	975	-225
$60	140	3,800	1,200	1,150	-50
$70	155	4,200	1,225	1,250	+50
$80	170	4,600	1,300	1,400	+200
$90	190	5,000	1,400	1,550	+350

60 EIA 2015g
61 Although this reflects a gradual price change rather than a sudden one
62 E.g. $4.50 increase in netback leads to 4.50/10 x 250 = 113 kbd in increased production.

in 2020, with any new tar sands growth not arriving until the early 2020s. Thus midstream capacity is not the limiting factor in our calculation.

In Table 9.3 below, we compare the potential additional production with potential downstream demand.

We see (right-hand column) that the PNW terminals could potentially enable an additional 76-114 kbd of Bakken production (in 2020), with the range depending on whether the new pipelines are built out of the Bakken. The result also depends on the economic analysis of how netbacks impact rig count and production being correct, and on which producers succeed in capturing those additional netbacks, compared to their being used to generate higher profitability for existing Bakken production.

INDIRECT IMPACTS ON PRODUCTION

The above figure might underestimate the true impact of the PNW terminals on Bakken production, as there are three indirect respects in which they may also have an effect: production flexibility, arbitrage and company finances.

The first is that the economic function of rail transport lies in its flexibility, which is especially valuable where production itself varies over time, as with shale. Pipeline take-or-pay contracts, in contrast, can lock producers into selling in a particular market for ten years or more. With uncertainty about future economics, a producer might prefer not to commit to a Gulf Coast pipeline, when rail to the West Coast could deliver similar netbacks and less risk of ultimately paying for unused transport capacity if its production declines.

Secondly, rail permits a dynamic approach to trading, where producers can adjust destinations according to where the best netbacks are. Our calculation in Section 6 estimated the average netbacks over time – but of course they will fluctuate according to crude price differentials in different markets. Each producer will have a different strategy, but one option is to use rail to capture the best prices at any particular time, at the cost of a higher tariff, potentially generating higher average netbacks. The more markets a producer has access to, the greater the advantages of this approach. This arbitrage opportunity is part of the reason why rail unloading capacity so exceeds the direct physical requirement.

The third indirect effect relates to the unknowable question of how the price fall is stressing the finances of the producing companies. A feature of the shale boom is that companies have racked up huge levels of debt. So far, companies appear to have put a brave face on it, but we do not know how long they – or their banks – can tolerate the difficulties. Many producers hedged against falls in oil prices: many of these positions will have expired over recent months, meaning that it is only more recently that producers have been fully exposed to the price changes.

Regulators are calling on banks to declare some oil loans troubled assets,[64] and some companies are finding it harder to raise equity finance, but face the next review of their loan positions this October.[65] With ExxonMobil and Shell having been unsuccessful in their forays into shale production, it is unclear whether there will be sufficient buyers, if smaller producers are forced to sell assets.

A difference of $2-$6/bbl in netback prices may not sound like much compared to recent global price falls – but if companies are really operating at the margins, it could be what makes the difference between keeping up with finance costs and being unviable as a company.

Table 9.3: Full System Potential, Additional Bakken Production Source: Oil Change International analysis

	Impact on netback		kbd		
	vs Gulf Coast pipe	vs East Coast rail	Upstream viability	Downstream light oil demand	Total system
Rail to PNW	$4.50	$6.00	113-150	26[63]	26
Rail + barge to PNW	$3.00	$4.50	75-113		
Rail to PNW + barge to California or tanker to China	$2.00	$3.50	50-88	411 plus Asia demand	50-88

63 Light + medium (if dilbit replaces ANS, Bakken would help balance it)
64 Jopson et al 2015
65 Crooks 2015

10. CONCLUSIONS: GREENHOUSE GAS EMISSIONS

On a fairly strict assessment of counterfactuals – what would be produced if the PNW rail terminals were built, compared to what would be produced if they were not? – we have found that they would directly lead to the additional extraction, by 2030, of:

- 154-275 kbd of new bitumen; and/or
- 0-215 kbd of new synthetic crude.

Where the amounts fall within these ranges will depend on the actual thresholds that companies apply to approving development of new projects.

It is harder to put a number on additional Bakken production, due to greater uncertainties in the economics, and because additional production would compete with non-additional production. We estimate that the PNW terminals could directly lead to additional extraction, by 2020, of up to:

- 76 kbd of Bakken oil if new pipelines are built, or
- 114 kbd of Bakken oil if they are not.

Research by the Carnegie Endowment for International Peace (CEIP)[66] has estimated the total greenhouse gas emissions associated with various types of crude oil, 'from well to wheel'. The study divides emissions for a particular crude into three components: those associated with (i) extraction (ii) refining and (iii) combustion. The third of these is the largest component, arising from the carbon content of the oil itself.

CEIP's analysis gives the emissions associated with a barrel of Cold Lake dilbit as 638 kg of CO_2 equivalent per barrel. Assuming the diluent to account for 400kg/bbl, the bitumen's share is 526 kg per barrel of dilbit, or 730 kg per barrel of bitumen.

The emissions associated with a barrel of synthetic crude oil are between 733 and 825 kg of CO_2e per barrel, depending on the specific synthetic type and source.

Estimates are not available for tight oil such as from the Bakken. However, we can make an estimate, by comparison with the CEIP study, that they are somewhere between 477 and 709 kg of CO_2e per barrel, with the degree of gas flaring, venting and leakage having the largest impact on where the per-barrel emissions fall in that range.[67]

The upstream direct impact of the PNW terminals would thus be as shown in Table 10.1.

Finally, we note that – in the absence of new pipelines – the terminals could handle only 382 kbd of new tar sands expansion, so not the upper end of the ranges for both bitumen and synthetic crude. The maximum emissions from bitumen and synthetic combined would be 106 MT CO_2e per year.

On top of this are indirect effects, such as:

- reducing the losses arising from existing and under-construction tar sands projects, thus facilitating further investment;
- reducing production risk in the Bakken;
- creating dynamic arbitrage opportunities for Bakken oil;
- reducing financial stresses on Bakken producers.

Table 10.1: Climate Impacts of the PNW Rail Terminals Source: Oil Change International analysis

Crude	Quantity unlocked / kbd	Emissions per barrel / kg CO_2e	Total unlocked emissions / million metric tons CO_2e per year
Bitumen	154-275	730	41-73
Synthetic crude	0-215	733-825	0-65
Bakken	0-114	477-709	0-30

66 Carnegie Endowment 2015

67 The emissions from refining and from combustion are determined by the composition of the oil. The light oils have refining emissions of 14-36 kg/bbl and combustion emissions of 394-460 kg/bbl. We assume Bakken oil will also be in this range. As for extraction emissions, the largest component outside the tar sands is from gas flaring. The high-flaring cases range from 50 to 275 kg/bbl. Aside from flaring, extraction emissions from comparable crude production in the Gordon study range from 31 to 73 kg/bbl. So total extraction emissions are 81-248 kg/bbl. In December 2014, the Bakken produced roughly 1,200 kbd of oil and sold 200 kbd (oil equivalent) of gas; following the Gordon approach, we allocate one seventh of the extraction emissions to the gas, leaving 69-213 kg/bbl.

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APPENDIX 1: **TRANSPORT COSTS**

Crude-by-rail costs divide into five elements:[68]

- Gathering/feeders: transporting crude from wellhead to rail terminal, either by trucking or with gathering pipelines;
- Tank car hire: most shippers lease their cars, rather than owning them; the rate will depend on what type of car they use, whether it is of higher safety standards, and whether it is heated in order to keep bitumen less viscous;
- Loading: loading onto railcars at the terminal; this is more expensive for more viscous heavy oil than for lighter grades;
- Tariff: the amount charged by the rail company that owns the track and operates the locomotives;
- Unloading: at the unloading terminal.

For shipments via PNW to California, there is also a cost associated with the barge or ship used to take the oil down the coast.

Table A1.1: Breakdown of Crude-by-Rail Costs to the PNW Multiple sources[69]

	Tar sands dilbit	Tar sands synthetic	Bakken	Notes
Gathering/feeders	(Up to $5.50)	(Up to $5.50)	($2-$3)	This varies according to where the field is located in relation to the terminal, and whether gathering lines are available (cheaper than trucking). However, Rystad economics data includes this element in the operating costs, so this will already be included in the calculation in Sections 7-8, and we can neglect it here
Tank car hire (per car)	$1,600 ±1,000	$1,600 ±1,000	$1,600 ±1,000	Note the wide variation: rates have fallen from around $2,500 to $500 in the last 2 years
Barrels per car	500-600	600-650	650-700	
Cycle time	9-12 days	9-11 days	6-9 days	Includes loading and unloading
Tank car hire	$1.00 ±0.70	$0.85 ±0.60	$0.60 ±0.50	This is calculated from the previous 3 rows
Loading	$1.65 ±0.15	$1.50 ±0.10	$1.40 ±0.10	
Tariff to PNW	$7.50 ±1.50	$6.60 ±1.50	$6.25 ±1.25	The lower end of this range will apply to take-or-pay contracts (which are generally around 2 years in duration, compared to 10+ years for pipelines); the higher end is for 'walk-up' rates

68 See CAPP 2014a pp.16-17 and RBN Energy 2014a pp.14-15 for more discussion of how these costs vary.

69 We have used multiple sources in assessing these, and cross-checked consistency between them: CAPP 2014a p.17 & 2014b p.42; Carlile 2015; Department of State 2014 pp.94-96; Fischer 2014 p.12; Fritelli 2014a p.14; Genscape 2015; Gibson Energy 2014 p.30; ICF International 2014 p.11; IHS Energy 2014 p.12; Koshka 2014 p.12; Millington 2014 p.15; PLG 2013 p.24; RBN Energy 2014a p.14 & 2014b pp.9-10; Searates.com 2015; Smith 2014 p.18; Stevens 2015 pp.23, 45; Stutzman 2014 p.2; Tesoro 2014 p.10; Zielinski p.12.

	Tar sands dilbit	Tar sands synthetic	Bakken	Notes
Unloading	$1.65 ±0.15	$1.50 ±0.10	$1.40 ±0.10	
Total to PNW terminals	$11.80 ±2.50	$10.50 ±2.30	$9.35 ±1.50	Plus gathering/feeders
Barge loading	$0.50	$0.50	$0.50	
Barge to Puget Sound refineries[70]	$1.10 ±0.50	$1.10 ±0.50	$1.10 ±0.50	
Total to PNW refineries	$13.40 ±3.00	$12.10 ±2.80	$10.95 ±2.00	Plus gathering/feeders
Barge to SF[71]	$2.30 ±0.50	$2.30 ±0.50	$2.30 ±0.50	We assume that shipments will go the shorter distance to San Francisco, as Los Angeles is an extra day's sailing in either direction. Los Angeles would continue to receive oil from Californian production and from imports. The range here reflects the size of barge used
Total to SF	$14.60 ±3.00	$13.30 ±2.80	$12.15 ±2.00	
Tanker loading	$0.50	$0.50	$0.50	Assuming no difference between dilbit, synthetic and Bakken loading costs
Tanker to China	$3.10 ±1.00	$2.90 ±1.00	$2.80 ±1.00	See Tables A1.3 and A1.4
Total to China	$15.40 ±3.50	$13.90 ±3.30	$12.65 ±2.50	

COST OF RAILING CRUDE TO OTHER DESTINATIONS

Since we compare the PNW netbacks with those for other potential rail export routes, we need to look at those routes' transport costs too.

Table A1.2: Breakdown of Crude-by-Rail Costs to Gulf Coast and East Coast Multiple sources[72]

	Dilbit to Gulf Coast	Synthetic to Gulf Coast	Bakken to East Coast	Bakken to Gulf Coast	Notes
Tank car hire (per car)	$1,600 ±1,000	$1,600 ±1,000	$1,600 ±1,000	$1,600 ±1,000	
Barrels per car	500-600	600-650	650-700	650-700	
Cycle time	16-20 days	16-20 days	9-11 days	12-16 days	
Tank car hire	$1.75 ±1.25	$1.50 ±1.25	$0.80 ±0.55	$1.10 ±0.75	
Loading	$1.65 ±0.15	$1.50 ±0.10	$1.40 ±0.10	$1.40 ±0.10	
Tariff	$14.00 ±2.00	$12.30 ±2.00	$10.00 ±1.00	$8.50 ±1.50	
Unloading	$1.65 ±0.15	$1.50 ±0.10	$1.40 ±0.10	$1.40 ±0.10	
TOTAL	$19.05 ±3.55	$16.80 ±3.45	$13.60 ±1.75	$12.40 ±2.50	Plus gathering/feeders

70 Assuming cycle time 2.5 days, from Grays Harbor; barge rates $110,000/day for 340,000 barrels / $80,000/day for 180,000 barrels, 23% fuel surcharge
71 Assuming cycle time 5-7 days; barge rates $110,000/day for 340,000 barrels / $80,000/day for 180,000 barrels, 23% fuel surcharge
72 Sources as Table A1.1, plus Fielden 2014; Freedenthal 2014; Global Partners 2014; Nemec 2014 Oil & Gas Journal 2014; Weeks 2014 p.18

COST OF SHIPPING TO ASIA

As noted in Section 5, no actual crude tanker shipping cost data are available for the route from the Pacific Northwest to Asia, because such trade does not currently occur. Here we make a rough estimate of the likely costs, hypothetically considering larger tankers than can be used in these terminals, for comparison with costs of any competing terminals.

Table A1.3: Estimated Cost of Shipping from Puget Sound to Shanghai, in Various Tanker Sizes (Suezmax and VLCC are included only for comparison)[73] Source: Bloomberg Professional

DWT	Class	Freight rate / $ per day[74]	Fuel cost / $ per day[75]	Total cost / $
55,000	Panamax	14,500	22,050	1.3m
70,000	Panamax	15,900	25,200	1.46m
105,000	Aframax	16,500	31,500	1.7m
150,000	Suezmax	21,400	41,000	2.21m
300,000	VLCC	26,800	63,000	3.16m

Table A1.4: Estimated Per-Barrel Cost of Shipping Dilbit, Synthetic Crude or Bakken from Puget Sound to Shanghai[76]

DWT	Class	Capacity dilbit / kb	Capacity synthetic / kb	Capacity Bakken / kb	Per-barrel cost dilbit / $	Per-barrel cost synthetic / $	Per-barrel cost Bakken / $
55,000	Panamax	350	390	410	3.71	3.33	3.17
70,000	Panamax	470	500	525	3.10	2.90	2.78
105,000	Aframax	710	760	790	2.40	2.20	2.15
150,000	Suezmax	1,010	1,080	1,130	2.20	2.10	1.96
300,000	VLCC	2,020	2,170	2,260	1.60	1.50	1.40

73 The distance from Puget Sound to Shanghai is roughly 5,000 nautical miles. At an average of 12 knots, the journey would take 17 days. With two days of docking and loading/unloading at either end, this would give a cycle time of 38 days, with 34 days of fuel use. Assume the vessel carries 20 days' fuel.

74 Simpson, Smith & Young charter rates, 3-year average from Bloomberg Professional, except 55,000 DWT (estimate)

75 At $630/MT (3-year average from Bloomberg Professional). Assuming 55k DWT Panamax consumes 35 MT/day, 70k DWT Panamax 40 MT/day, Aframax 50 MT/day, Suezmax 65 MT/day, VLCC 100 MT/day

76 Dilbit density 926 kg/m^3, synthetic 864 kg/m^3

APPENDIX 2: **SALES PRICE AT MARKET**

One of the biggest determinants of oil economics is of course the hardest to predict: the price of oil. And it is not only the global benchmark prices such as Brent and West Texas Intermediate (WTI) that will vary in the future, but also the differentials of local prices – and these are no easier to predict. In Appendix 3, we will consider various scenarios for oil price forecasts; here we make a best estimate of how to adjust these to give sales prices on the U.S. West Coast.

HOW PRICES ARE SET

With no pipelines bringing oil from the U.S. Midcontinent across the Rockies, the West Coast functions more like an island connected to the global oil market than as part of the U.S. continental market. Before 1990, the West Coast price was shaped primarily by the supply and demand dynamics of Californian and Alaskan production. But since they have declined, prices on the West Coast are determined by international prices (with Brent and Dubai/Oman the key benchmarks) rather than domestic ones (WTI and Louisiana Light Sweet).

Why do imports rather than local production shape prices? Basically, if the North American producers tried to sell at a higher price, the refineries would then switch to sourcing more (or all) from cheaper imports, and the North American oil would be left without a market. So those producers have to accept the international price if they want to sell their oil. On the other hand, if the import price rose, the North American producers would not have enough oil to substitute it all, so their sales price would rise with it.

Crude oil prices vary by location and type of crude. Price differentials relative to benchmark crudes consist of three elements:

- Quality: this reflects the crude's value to refiners, according to their processing cost and the value of products they can produce. Light (low-density), sweet (low-sulfur) crudes are the most valuable, because they can be more cheaply converted into high-value products such as gasoline, diesel and aviation fuel.
- Transportation: the cost of getting crude from its point of origin to the refiner.
- Supply and demand: imbalances in the market can cause wider fluctuations, due to disruptions of supply or demand of a particular crude quality, or due to constraints to market access.

ESTIMATING THE WEST COAST SALES PRICE DIFFERENTIAL

As a first step, we select as proxies the major imported crudes that are closest in API gravity (density) and sulfur content to the North American crudes delivered there: Oriente from Ecuador as a proxy for dilbit, and Arab Light and Arab Extra Light, both from Saudi Arabia, as proxies respectively for synthetic crude and Bakken.

The main global benchmark is Brent, and in our modeling we will consider forecasts of its price. Assuming that supply and demand effects even out over time for ocean-traded crudes, our model adjusts forecast Brent prices according to the three proxies' average price differentials to Brent over the last three years.

These prices are as delivered in the export ports in Ecuador (Esmeraldas) or Saudi Arabia (Ras Tanura), so next we adjust these according to the cost of shipping to the U.S. West Coast, to give the price they would sell for there. Both steps are shown in Table A2.1 below.

Finally, since our three North American crudes are not exactly the same as the proxies, we need to adjust for quality differences from them. This reflects the extra cost to refiners of processing greater quantities of the denser fractions, or of removing sulfur.

There are various methods for estimating this differential; we use a simple formula, where each extra degree of API gravity adds $0.30 to the value, and each extra percentage point of sulfur content subtracts $0.93 from its value.[77] We apply this formula to the quality differences of tar sands and Bakken crudes from their proxies, in Table A2.2, below.

Going through these steps, we estimate prices as follows:

- Dilbit price on West Coast = Brent price x 87.5% + $3.50 - $2.54
- Synthetic crude price on West Coast = Brent price x 93.7% + $2.60 + $1.34
- Bakken price on West Coast = Brent price x 100.4% + $2.60 + $0.84

EAST COAST AND GULF COAST PRICE DIFFERENTIALS

Again, in order to compare netbacks with those for other destinations, we need to estimate sales prices there, using the same approach.

Table A2.1: Historical Differentials of Middle East Crudes vs Brent, and Shipping Cost from Persian/Arabian Gulf to U.S. West Coast
Source: Bloomberg Professional (monthly average prices)

Crude	Proxy	Proxy differentials vs Brent (3-yr average)	Transport cost from origin
Dilbit	Oriente	-12.5%	$3.50
Synthetic crude	Arab Light	-6.3%	$2.60
Bakken	Arab Extra Light	+0.4%	$2.60

Table A2.2: Adjusting for Quality of Imported Proxies Relative to North American Inland Crudes on the West Coast[78]

Crude	API	Sulfur	Proxy	API	Sulfur	Quality diff vs proxy
Dilbit	20.5°	3.0%	Oriente (Ecuador)	24°	1.4%	-$2.54
Synthetic	32°	0.2%	Arab Light (Saudi Arabia)	32.5°	1.8%	+$1.34
Bakken	39°	0.2%	Arab Extra Light (Saudi Arabia)	39°	1.1%	+$0.84

Table A2.3: Estimating Sales Price in Asia Source: Bloomberg Professional; Oil Change International

Crude	API	S	Market	Proxy	API	S	3-yr proxy diffs vs Brent	+ Transport	Quality diff vs proxy
Dilbit	20.5°	3.0%	Asia	Arab Heavy	27°	2.8%	-9.6%	$1.40	-$2.14
Synthetic	32°	0.2%	Asia	Arab Light	32.5°	1.8%	-6.3%	$1.40	+$1.34
Bakken	39°	0.2%	Asia	Arab Extra Light	39°	1.1%	+0.4%	$1.40	+$0.84

Table A2.4: Estimating Sales Price at Other Locations Source: Bloomberg Professional; Oil Change International

Crude	API	S	Market	Proxy	API	S	3-yr proxy diffs vs Brent	+ Transport	Quality diff vs proxy
Dilbit	20.5°	3.0%	Gulf	Maya	21.1°	3.4%	-12.4%	$0.94	+$0.19
Synthetic	32°	0.2%	Gulf	LLS	35.7°	0.4%	-2.1%	0	-$0.92
Bakken	39°	0.2%	East Coast	Brent	38.0°	0.4%	0	$1.37	+$0.49
Bakken	39°	0.2%	Gulf	LLS	35.7°	0.4%	-2.1%	0	+$1.18

77 IHS/Purvin & Gertz 2012. This is known as the Bulk Property or Quality Bank method. The other common method, known as Linear Programming or Refining Value, necessitates complex modelling of individual refinery configurations and economics. See also Bacon & Tordo 2005; Birch 2014; Pavlovic 1999.

78 The API and sulfur content given here are for Western Canada Select, Syncrude Sweet Premium and Bakken Blend – there will of course be some variation.

APPENDIX 3: **SENSITIVITY ANALYSIS**

The aim of this appendix is to explore how things could be different, if circumstances change.

FORECASTING OIL PRICE VARIABILITY

The oil price is the biggest determinant of oil project economics, yet no one knows confidently what the price will be in the future. Most analysts currently expect the price to stay low in the coming years, if Saudi Arabia continues to pursue a market share strategy (which it shows every sign of doing), if U.S. production remains relatively resilient to lower prices; other factors keeping the price down are the return of higher Iranian exports to the market, and economic woes in China limiting demand. Some believe, however, that reduced levels of investment could lead to a shortfall of production in a couple of years' time, which could cause a strong bounce-back to high prices, potentially even higher than the $100 range before the crash. Political events in the Middle East can also have a dramatic upward effect on the price.

The way oil companies deal with this uncertainty is by considering their investments in a range of price scenarios: whether it would deliver acceptable returns in a most likely scenario, the opportunity of a windfall if prices are higher (upside), and the risk of a loss if they are lower (downside).

In our analysis, we consider scenarios where the oil price is either 10% higher or 10% lower than in the EIA Reference Case. This gives an indication of possible price variations within essentially the same market structure. Of course, price can change more dramatically, as the last year has shown. However, the larger changes in price are less interesting for us, as they would dwarf any differences in transport costs, and make every project and every export route very profitable at high price, and extremely loss-making at low price.[79]

IMPACT OF PRICE ON NETBACK ANALYSIS

We see from Charts A1.3 to A3.3 that changes in the oil price do not generally change the order of which destinations deliver the highest netbacks, with a couple of small exceptions. The most significant of these exceptions is (perhaps surprisingly) that for synthetic crude, PNW rail becomes more attractive than Gulf Coast pipelines at lower prices.

79 For this reason we do not use the alternative price forecasts in the EIA's Annual Energy Outlook. The EIA's High Price Case – where Brent is already $135 in 2016 – would reflect either a supply shock (such as conflict in the Middle East) or a restructuring of the market from current expectations (such as OPEC switching to a price-supporting strategy). In contrast, a Wall Street Journal survey of financial analysts in 11 major banks found that they all predicted much lower 2016 average prices – ranging in the survey from $56 to $93 (and all but one of them below $80) (Kantchev 2015). The EIA's Low Price Case – where Brent remains below $70 in real terms until the early 2030s – would represent a situation where current over supply persists, and there is no cyclical recovery. Of course, the EIA's alternative price scenarios are not impossible, but since they would respectively give every project/export route IRRs of 20-30% or of around 0%, they do not tell us much about the PNW rail terminals.

Chart A3.1: Dilbit Netbacks by Scenario (2025) Source: Oil Change International analysis

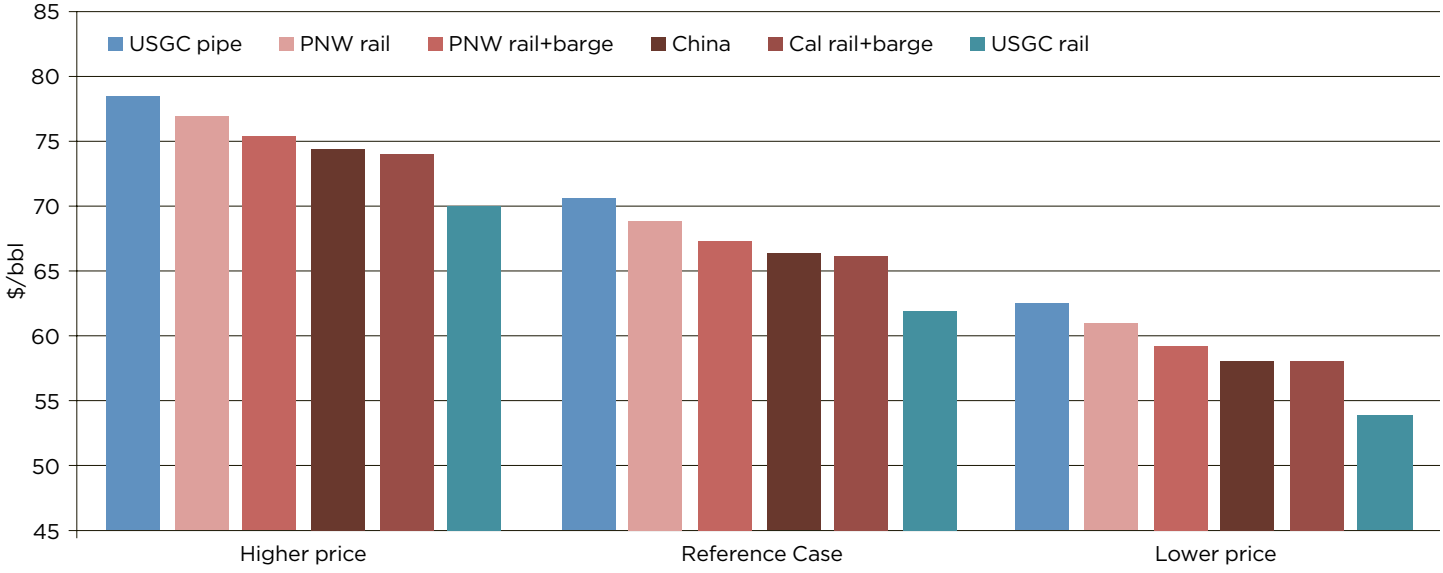


Chart A3.2: Synthetic Crude Netbacks by Scenario (2030) Source: Oil Change International analysis

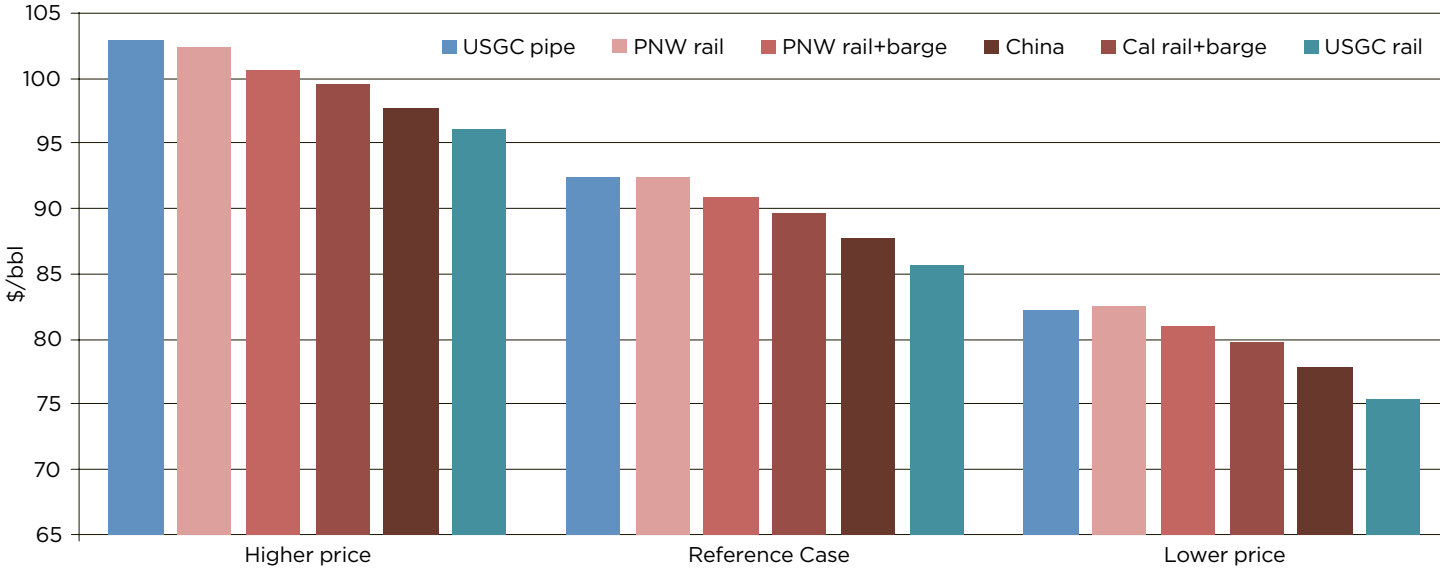
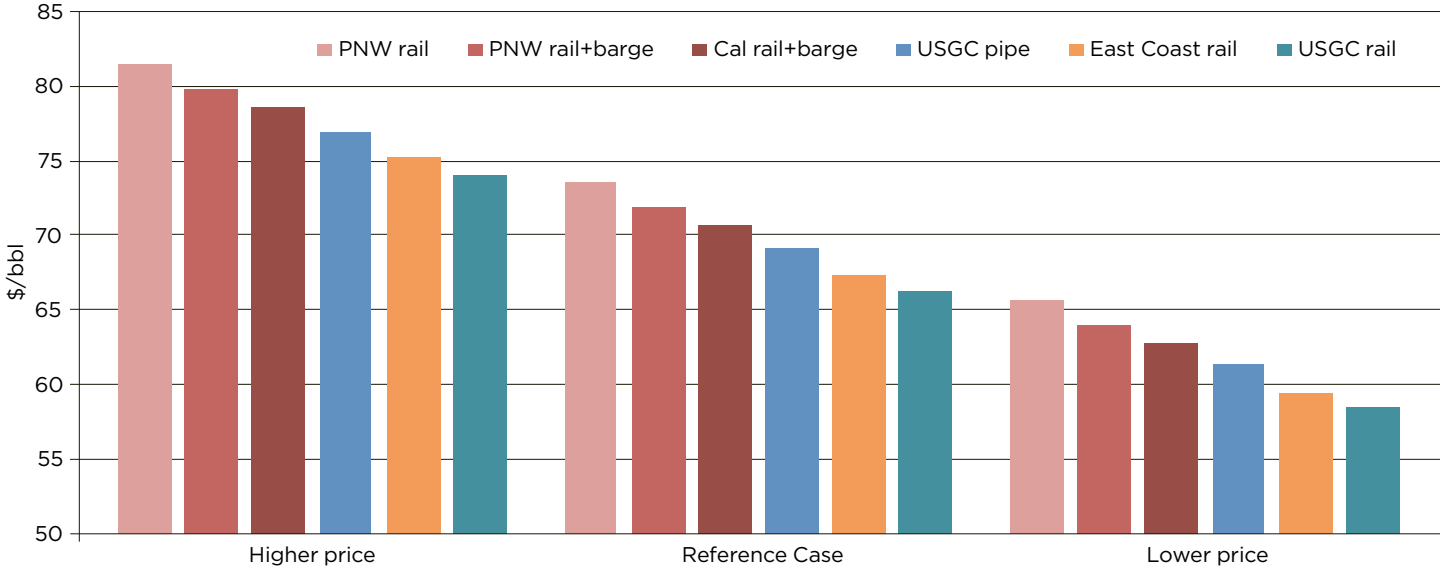


Chart A3.3: Bakken Netbacks by Scenario (2020) Source: Oil Change International analysis



IMPACT OF PRICES ON TAR SANDS IRR ANALYSIS

The Table A3.1 shows how sensitive tar sands projects are to lower prices. Even the fairly modest price increase/decrease of 10% pushes all bitumen projects, for all export routes, respectively above/below the 10% IRR threshold.

As noted before, any investment decision will depend on a company's attitude toward risk (and its wider economic/strategic position). In the lower-price scenario, the 8-9% IRR for Gulf Coast pipe, and perhaps the 7-8% for PNW rail + barge, might be considered acceptable downside risk, although they would not be enough to justify investment if it was considered a likely scenario. Gulf Coast rail would entail unacceptably low returns in that scenario.

The conclusion is that if prices rose above expectation, and were then expected to stay higher, the impact of PNW rail terminals would be diminished, as more costly export routes could become viable.

Synthetic crude projects are more resilient to lower prices, and less sensitive to the varying costs of export routes, as discussed in Section 7.

Table A3.1: Dilbit Rates of Return under Different Price Scenarios Source: Oil Change International cashflow models

Project	Rystad breakeven	Higher price				Lower price			
		Gulf Coast pipe	Gulf Coast rail	PNW rail + barge	Calif. rail + barge	Gulf Coast pipe	Gulf Coast rail	PNW rail + barge	Calif. rail + barge
Christina Lake 3B	74-75	13.9%	11.9%	13.3%	13.0%	9.0%	6.0%	7.9%	7.6%
Foster Creek J	76-77	14.5%	12.3%	13.6%	13.3%	9.5%	6.8%	8.6%	8.2%
Sunrise 2A	88-89	12.6%	10.8%	12.0%	11.7%	8.1%	5.9%	7.3%	7.0%
Christina Lake H	91-92	11.7%	10.4%	11.2%	11.1%	8.4%	6.8%	7.8%	7.6%%
Birch Mountain 1	102-103	12.1%	10.5%	11.6%	11.3%	7.8%	5.8%	7.1%	6.8%

Table A3.2: Synthetic Crude Rates of Return under Different Price Scenarios Source: Oil Change International cashflow models

Project	Rystad breakeven	Higher price				Lower price			
		Gulf Coast pipe	Gulf Coast rail	PNW rail + barge	Calif. rail + barge	Gulf Coast pipe	Gulf Coast rail	PNW rail + barge	Calif. rail + barge
Syncrude Mildred Lake 3	81-82	14.0%	13.2%	13.7%	13.5%	11.0%	10.0%	10.7%	10.6%
Jackpine 1B	83-84	13.3%	12.7%	13.2%	13.1%	10.8%	10.0%	10.6%	10.4%
Terre de Grace 1	89-90	12.0%	11.2%	11.6%	11.5%	9.1%	8.1%	8.8%	8.7%
Firebag 5	93-94	11.1%	10.4%	10.8%	10.7%	8.7%	7.9%	8.5%	8.4%
Muskeg River Expansion	95-96	11.6%	10.8%	11.4%	11.2%	8.7%	7.8%	8.5%	8.3%

SENSITIVITY TO COST CHANGES AND PRICE DIFFERENTIALS

Global oil prices change the profitability of all oil projects, so the relative attractiveness of different export routes is little changed. More significant to our analysis are potential variations in transport costs, and in price differentials in the key markets – both of which will change that relative position.

It is in the nature of crude-by-rail that costs are more variable than for pipelines, which are relatively consistent. A company may succeed in getting a good deal on a tariff; a terminal operator or railroad company may reduce costs (and charges) through efficiencies; hire rates for tank cars can vary significantly according to supply and demand; geographical location of terminals can alter the transit time. For waterborne transport, the size of the vessel makes a big difference. In Appendix 1, we indicated a range of uncertainty in the transport costs, arising from these factors: a lucky or skillful shipper may achieve the lower end of the range.

These error bars – ranging from $1.50/bbl to $3.50/bbl for rail options – exceed some of the differences between netbacks arising from different export routes. What this implies is that – in the volumes analysis in Section 9 – there will be overlaps between the different market options, rather than oil going to the second-highest-netback destination only after all of the first's capacity has been exhausted. However, as averages our earlier analysis should hold.

Another key distinguishing factor is that differentials between crudes of different qualities, or in different markets, fluctuate significantly, just as global benchmark prices do. Our original estimates relied partly on the three-year average of the differential between the proxy crude and Brent, and on the cost of transporting the proxy to the relevant market. In the tables below, we show a range, to indicate the netbacks reflecting the three-year interquartile range of those price differentials and tanker costs (i.e. one end of the error bar reflects the first quartile and the other the third).

Again, we see that the impact of the price differentials is of the same order as differences between different routes' netbacks. In this case, however, we cannot assume that these variations will average out: while the values we've used are our best guesses of what the differentials will be in the future, no one can say whether the markets will behave as we expect.

They should not change the order of market preference at the extremes: for example, rail to the Gulf Coast or East Coast in the optimal case is still less attractive than rail to the PNW in the worst case. It may, however, affect the competition for Bakken volumes between PNW rail and pipelines to the Gulf Coast – although it should be noted that pipeline decisions are generally made over a longer time period. Thus a lasting shift in oil price differentials could make a difference, whereas a fluctuation would not so much.

Similarly, shifts in price differentials from what we have anticipated may affect IRRs in tar sands project planning, but only if prices are settled.

In summary, significant and lasting changes in oil prices and expectations (both global benchmarks and local differentials) could change our analysis. These changes are not predictable; however we have considered the outcomes using the best estimates available.

Table A3.3: Dilbit: Impact of Proxy Differentials on Netback Price (2025) Source: Oil Change International analysis

	High	Mid	Low
Gulf Coast pipe	$73.26	$70.46	$66.82
PNW rail	$71.44	$68.90	$66.39
PNW rail+barge	$69.84	$67.30	$64.79
China	$69.36	$66.25	$64.39
Cal rail+barge	$68.64	$66.10	$63.59
Gulf Coast rail	$64.71	$61.91	$58.27

Table A3.4: Synthetic Crude: Impact of Proxy Differentials on Netback Price (2030) Source: Oil Change International analysis

	High	Mid	Low
Gulf Coast pipe	$94.93	$92.50	$91.23
PNW rail	$96.83	$92.42	$91.61
PNW rail+barge	$95.23	$90.82	$90.01
Cal rail+barge	$94.03	$89.62	$88.81
China	$91.83	$87.82	$86.89
Gulf Coast rail	$88.13	$85.70	$84.43

Table A3.5: Bakken: Impact of Proxy Differentials on Netback Price (2020) Source: Oil Change International analysis

	High	Mid	Low
PNW rail	$74.92	$73.53	$72.62
PNW rail+barge	$73.32	$71.93	$71.02
Cal rail+barge	$72.12	$70.73	$69.82
Gulf Coast pipe	$70.96	$69.14	$68.19
East Coast rail	$67.66	$67.39	$67.19
Gulf Coast rail	$68.06	$66.24	$65.29

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NOVEMBER 2015