

**U.S. West Coast Refineries**  
Prepared for NextGen and NRDC

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## 1 Executive Summary

### 1.1 Introduction

This study includes projection of the extent that tar sands crude will reach the west coast refining market (California and Washington states) by 2040. The Chevron Refinery in British Columbia is also briefly addressed in an appendix.

For the purposes of this study, we make projections based on three different scenarios:

#### **Constrained Scenario**

No new pipelines are constructed under this scenario. Crude movements will continue to be constrained by pipeline bottlenecks, with any additional crude uptake going by rail.

#### **Kinder Morgan Tans Mountain Expansion Scenario**

This scenario assumes the Kinder Morgan TME pipeline is constructed, but not cross-border pipelines.

#### **Unrestrained scenario**

All pipelines are approved including Kinder Morgan Trans Mountain Expansion, Enbridge Northern Gateway and Keystone XL.

There are four factors effecting future tar sands crude usage at West Coast Refineries:

1. Refinery capacity to take heavy crude, in particular tar sands bitumen
2. Logistics infrastructure (pipeline and rail offloading terminals, including both tanker and barge transshipments)
3. Economic factors (arbitrage, or price differentials in different geographic markets, and competing demand in other regions)
4. Availability of local domestic crudes (e.g. California, Alaska, and light tight crude)
5. Supply of Western Canadian Sedimentary Basin crude
6. Political and legislative constraints

Our analysis does not address price differentials as they are notoriously difficult to predict in any meaningful way.<sup>1</sup> Nor does our analysis consider political or legislative constraints, such as “AB32” in California which requires a 10% reduction in carbon intensity of fuel supplied within California by 2020.

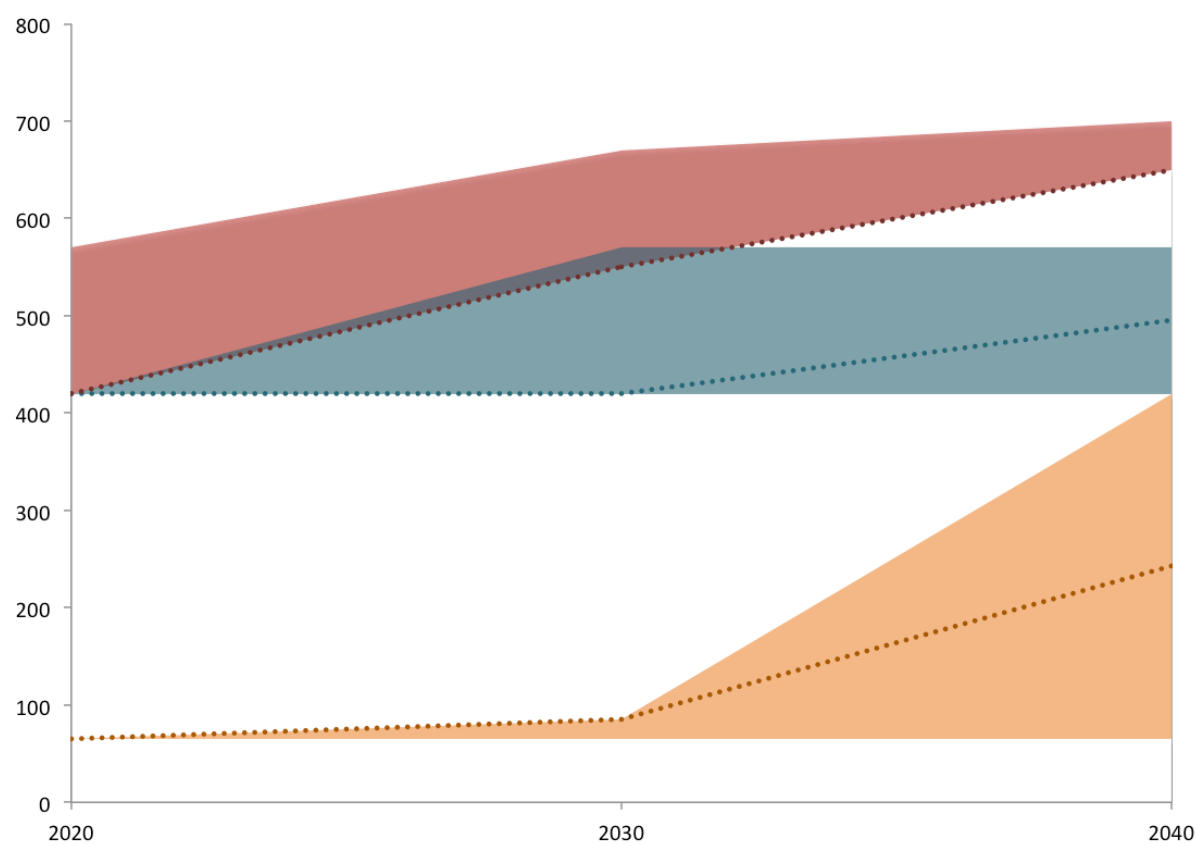
Most of the uptake will be of bitumen blend. This can be transported in two forms: bitumen blend (e.g. dilbit, synbit, etc.) and raw bitumen (including railbit), and can be moved to west coast refineries via a combination of pipeline, rail, tanker and barge. Synthetic Crude Oil (SCO) shipments to west coast refineries are not expected to grow by much and are discussed in an appendix.

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<sup>1</sup> Wood Mackenzie, for example, in a report produced for the Alberta Department of Energy, did not attempt to estimate the magnitude of price discounts because “the economic value of this discount is so specific to the configuration and operating environment of each refinery.” [Wood Mackenzie, “A Netback Impact Analysis Of West Coast Export Capacity”, produced for Alberta Department of Energy, December 2011]

Bitumen usage at west coast refineries is expected to range from as low as 35,000 bpd (status quo) to as high as 650,000 bpd or more (see Figure 1 – dotted lines represent the most likely volumes). The driving factors of these projections are if and when pipeline(s) are built, but other factors influence the projections as well, including domestic crude production in the U.S. and crude on rail offloading capacity.

Figure 1: Range of Bitumen Blend Projections Under Each Scenario (thousand bpd)



Scenario		2020	2030	2040
Unconstrained	Bitumen blend:	420 - 570	550 - 670	650 - 700
	SCO:	90	90	90
Kinder Morgan Trans Mountain Expansion	Bitumen blend:	420	420 - 570	420 - 570
	SCO:	75	75	75
Constrained	Bitumen blend:	65	65 - 85	65 - 420
	SCO:	35	35 - 50	35 - 75

## 2 Projections

### 2.1 Overview

Overarching points:

- Bitumen refining is constrained by coking capacity.
- Refineries in California are highly geared towards processing heavy crudes and many are capable of refining bitumen.
- Demand for SCO is greater in most other regions. SCO refining is also constrained by FCC capacity.
- Crude-on-rail maximum capacity is impossible to predict. For the purposes of this study, we assume that significant increases in tar sands crude shipments via rail to PADD V, particularly California, for the most part will not occur until after domestic tight crude production has peaked (see Chapter 3.3)

Under most scenarios, the majority – 85 to 90 percent – of the tar sands oil that will be imported into PADD V in the future will be bitumen blend, the rest being bitumen-derived synthetic crude oil (SCO). Note that bitumen blend and SCO projections are presented separately in the following charts and tables because they are effected by different factors in different ways: for example, increased input of bitumen blend in refineries will also more more refining of condensates which may in turn offset some SCO refining capacity.

Figure 2: PADD V Bitumen Blend Imports According to Two Different Projections (thousand bpd)

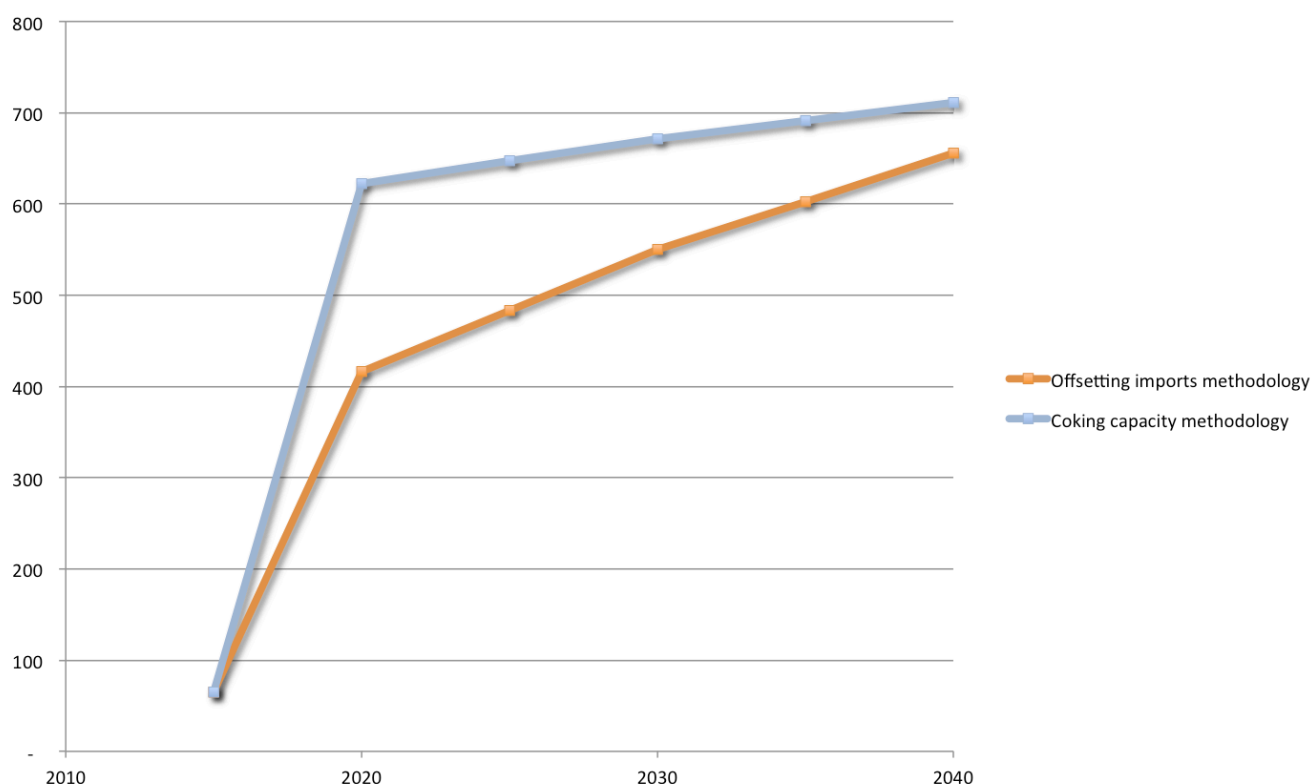


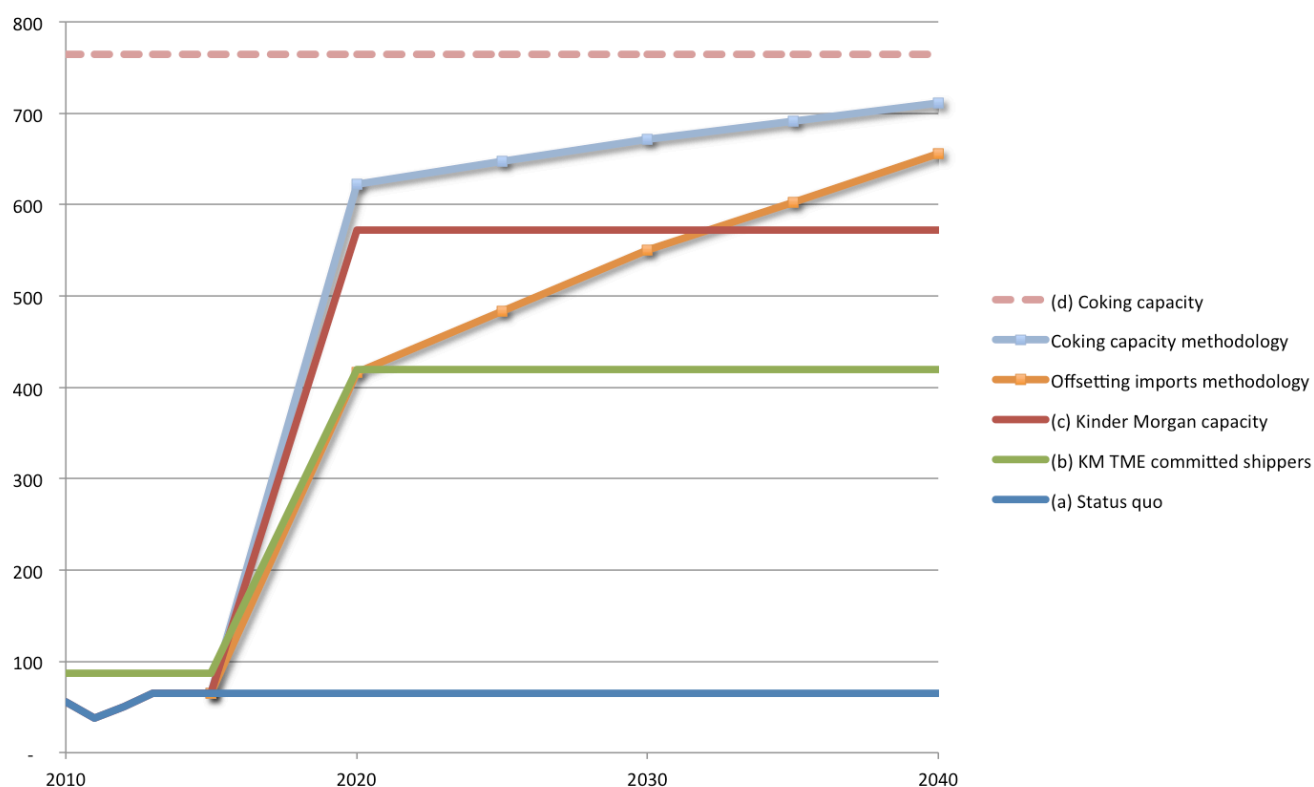
Figure 2 shows estimated volumes of bitumen blend that would reach refineries in California and Washington according to two different projections: using the *offsetting imports methodology* (based on a calculation proposed by the University of Calgary, updated using more recent data from the EIA and Rystad Energy), and using the *coking capacity methodology* (a methodology developed by Borealis incorporating both bottom-of-the-barrel and coking capacity). Both methodologies taking into account predicted changes in domestic production of heavy crude in California and Alaska. The former methodology represents more of a realistic estimate while the latter represents more of a theoretical maximum.

The key point here is that both projections tend to converge over time.

Figure 3 shows these two projections in the context of various other figures: (a) status quo current bitumen blend import volumes of about 65,000 bpd; (b) Kinder Morgan Trans Mountain Expansion committed shippers-based estimate of about 420,000 bpd; (c) Kinder Morgan heavy capacity available for PADD V; and (d) total coking capacity in PADD V (the upper ceiling for bitumen blend usage in PADD V).

The Kinder Morgan committed shippers line represents a minimum short-term outlook in a non-constrained scenario. In a constrained scenario, where no pipelines are build to the west coast of British Columbia, bitumen blend imports could theoretically still reach this level eventually, provided the long term economics of crude-on-rail are favorable. In this case, it would represent more of a maximum value than a minimum.

Figure 3: PADD V bitumen blend import projections overlayed on top of various other figures (thousand bpd)



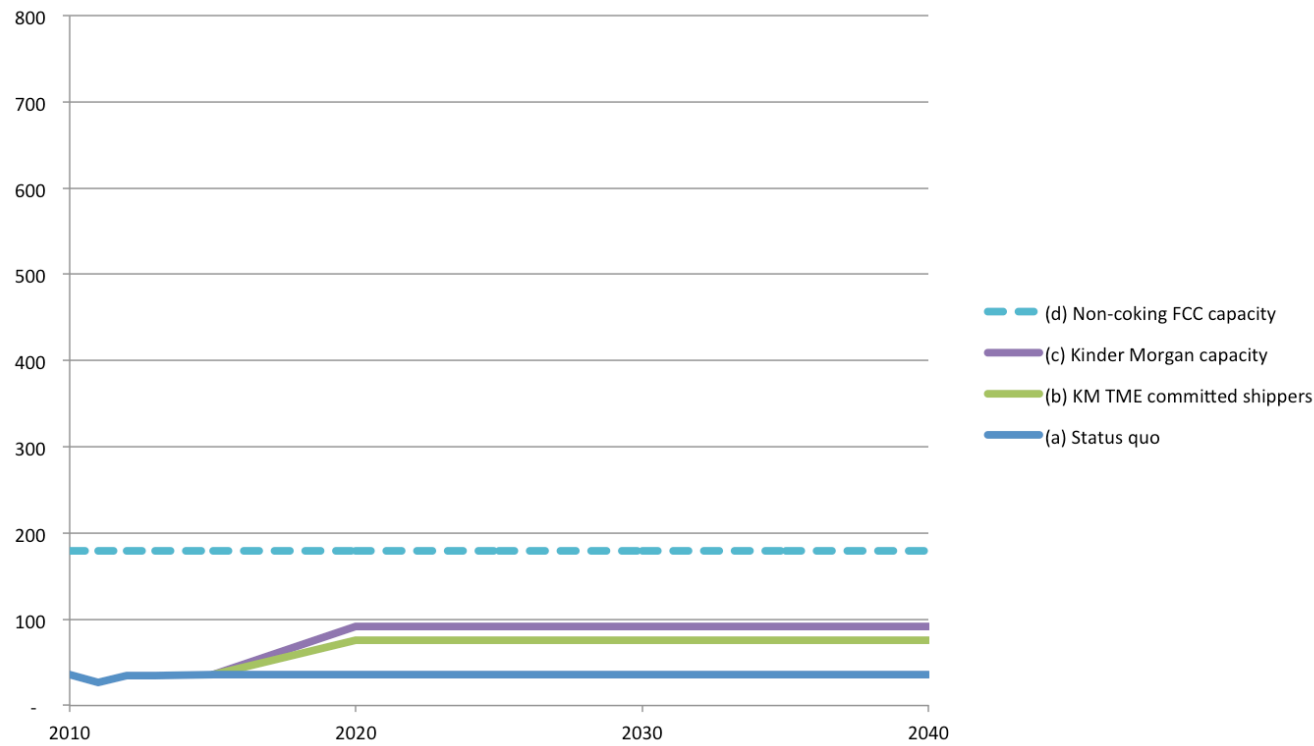
Note that both of the projections (offsetting imports methodology and the coking capacity methodology) both exceed the Kinder Morgan pipeline heavy capacity. This is possible if a second pipeline were to be built in B.C. (such as the proposed Enbridge Northern Gateway pipeline), if some of the Kinder Morgan light carrying capacity is utilized to instead carry heavy crudes in the future, or in the case of the offsetting imports methodology if crude-on-rail is also utilized after 2030.

As evident in Figure 4, SCO uptake in PADD V is expected to be far less. This is discussed in length in the appendices.

Figure 4 shows various SCO figures: (a) status quo current SCO import volumes of about 35,000 bpd; (b) Kinder Morgan Trans Mountain Expansion committed shippers-based estimate of about 75,000 bpd; (c) Kinder Morgan SCO capacity of about 90,000 bpd; and (d) estimated total non-coking FCC capacity in PADD V.

The Kinder Morgan committed shippers figure represents the most likely volumes of SCO to be used in PADD V (under the constrained scenario, SCO may also reach these levels, though it may take longer for available crude-on-rail capacity to shift from Bakken to SCO). The estimated non-coking FCC capacity figure is also displayed on the chart – this more-or-less represents a physical limit in the volumes of SCO that could be processed in California and Washington; however, as described above and in the main report, market forces are by far the prime constraining factor dictating SCO usage in PADD V, and there is no evidence suggesting that SCO would ever reach this level. Instead, the Kinder Morgan capacity represents a more realistic maximum level for SCO.

Figure 4: SCO projections (thousand bpd)

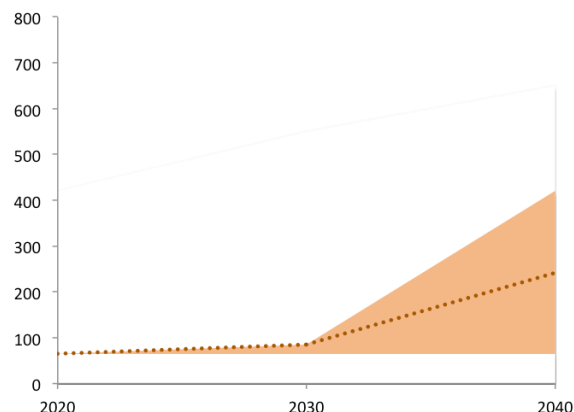




## 2.2 Constrained Scenario

		2020	2030	2040
PADD V total	Bitumen blend:	65	65 - 85	65 - 420
	SCO:	35	35 - 50	35 - 75

The constrained scenario represents the minimum amount of tar sands oil that would be moved to PADD V. Here, we assume that no pipelines to the west coast are constructed, and that a limited increase in crude-on-rail shipments would likely only occur after Bakken and other tight crude production has peaked and total tar sands supplies subsequently become greater than LTC supplies in North America. This would occur sometime after 2025 (for the purposes of this study we assume 2030), and could bring bitumen blend and SCO consumption in PADD V up to about the level that Kinder Morgan is projecting. We believe this represents the maximum value in the constrained scenario.

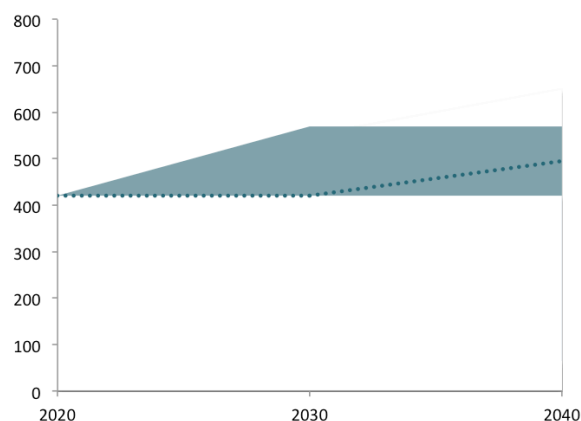


In the interim period, there could be some creep in usage of both bitumen blend and SCO via crude on rail. Here, we assume this does not exceed the volumes that are currently requested by shippers on the Kinder Morgan Trans Mountain pipeline, which Kinder Morgan has not been able to accommodate due to existing pipeline capacity constraints. This estimate is based on actual shipment volumes combined with published apportionment level for 2012 plus the first quarter of 2013. We conservatively assume no increase beyond current nominated volumes under this scenario.

## 2.3 Kinder Morgan Trans Mountain Expansion Scenario

		2020	2030	2040
PADD V total	Bitumen blend:	420	420 - 570	420 - 570
	SCO:	75	75	75

This scenario assumed the Kinder Morgan Trans Mountain Expansion pipeline is built, bringing the total pipeline capacity from 300,000 to 890,000 bpd. The minimum values under this scenario are clearly those which Kinder Morgan itself has disclosed as its committed shipper volumes. While it is possible that Kinder Morgan could ship more to PADD V, the company itself admits that over time it expects to see growth in demand in Asia, particularly China, for bitumen blend. Nonetheless, we present the pipeline heavy capacity as the upper limit for bitumen blend usage in California and Washington under this scenario. SCO is not projected to go beyond Kinder Morgan's committed shipper volumes.

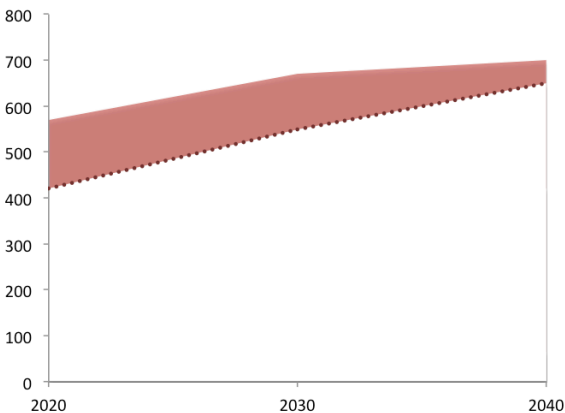


## 2.4 Unconstrained Pipeline and Rail Scenario

		2020	2030	2040
PADD V total	Bitumen blend:	420 - 570	550 - 670	650 - 700
	SCO:	90	90	90

The unconstrained scenario represents a maximum outlook for tar sands usage in California and Washington. There are competing forces at play: Keystone XL would bring SCO to Texas while Energy East would bring SCO to East Coast refineries, thereby keeping it out of far less suitable PADD V refineries; Kinder Morgan and Northern Gateway would both bring bitumen blend and SCO to Asian markets, but if they are both constructed then it would allow for much greater bitumen blend imports into PADD V, and a modest increase in SCO as well.

Therefore, under this scenario we assume that PADD V refineries could receive as much tar sands oil as they realistically can use. For bitumen blend, the range is between the two projections previously cited (but capped by Kinder Morgan's capacity initially in 2020).



## 3 Appendices

### 3.1 Offsetting imports methodology

Muse Stancil estimates the total market potential for Canadian heavy crude (i.e. bitumen blend) in California is up to 450,000 bpd.<sup>2</sup> Although they do not disclose their methodology, it is apparent that they are simply looking at the total coking capacity. The School of Public Policy at the University of Calgary remarks however that their estimate is too optimistic, adding that “the actual capacity will be lower due to logistical and capacity constraints not comprehended in the Muse Stancil methodology,” and instead provides an estimate of 300,000 bpd. This estimate is based primarily on the assumption that bitumen blends will replace heavy crude imports into California once supply constraints are lifted, namely an increase in pipeline capacity.<sup>3</sup> The study goes on to say that the calculation could be modified to project into the future if declining production figures for Alaska and California are also taken into account.

Heavy crude imports into California have since dropped off, and the University of Calgary’s estimate is no longer directly applicable, so instead we use heavy crude import figures for 2011, when imports peaked into PADD V.

The *offsetting imports methodology* combines these 2011 import figures with changing domestic crude production projections from Rystad Energy.

The formula is as follows:

$$\text{West Coast Bitumen Processing Capacity} = ( \text{Heavy Imports} + \text{Change in California and Alaska Production} ) * \text{Bitumen Blend Adjustment}$$

Where *Bitumen Blend Adjustment* represents bitumen blend as a percent of total heavy crude produced in western Canada.

### 3.2 Coking capacity methodology

This methodology considers coking capacity that is currently being used to process domestic and imported heavy crudes other than bitumen and bitumen blends.

We calculate the heavy crude capacity (i.e. the approximate capacity of a given refinery to take heavy crude streams) as the combined capacity of a refinery’s coking, catalytic cracking and hydrocracking units. This is sometimes referred to the *bottom of the barrel* capacity.<sup>4</sup> Tar sands bitumen refining capacity is assumed to roughly equate to a refinery’s coking unit capacity. This is an approximation as some refineries can take more and some can take less depending on specifics of their configuration, but it is a reasonable estimate when

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<sup>2</sup> Muse Stancil, “Market Prospects and Benefits Analysis for the Northern Gateway Project”, prepared for Enbridge, January 2010.

<sup>3</sup> University of Calgary, The School of Public Policy, SPP Research Papers Volume 6, Issue 8, February 2013 (“Pacific Basin Heavy Oil Refining Capacity”).

<sup>4</sup> This is part of the “Bottom of the Barrel” (BoB) Index as defined by

looking as a large enough sample size (in this case, all west coast refineries). Note that the margin of error for this estimate increases as the sample size decreases and the estimate does not apply on an individual refinery basis. Therefore, our projections are more accurate when considering the entire west coast as a whole, but less accurate when looking at just Washington state in particular.

The formula is as follows:

$$\text{West Coast Bitumen Processing Capacity} = ( \text{Heavy Capacity} - \text{Heavy Imports} - \text{Heavy Production} ) * \text{Extra Heavy Capacity Ratio}$$

Where *Extra Heavy Capacity Ratio* is defined the percentage of heavy capacity that is extra heavy capacity. This is calculated as coking capacity divided by heavy capacity. Application of this ratio helps to reduce the margin of error. Hart Energy predicts no change in west coast heavy capacity and therefore the *Extra Heavy Capacity Ratio* is unlikely to change.

For west coast refineries, *Heavy Production* is a combination of California and Alaska heavy crude production. Although Alaska historically has not produced heavy crude, some limited volumes may be produced in the future.

### 3.3 Light, Tight Crude

U.S. light, tight crude (LTC) production is expected to peak sometime after 2020 and will follow a downward trend after that (see Figure 5). Meanwhile, tar sands production is expected to continue to rise long after LTC has peaked. Tar sands heavy crude (i.e. bitumen blend) production will surpass U.S. LTC by 2030.

Although the volumes are currently quite small (see Figure 6), we estimate the total capacity of all existing, planned and proposed crude-on-rail offloading facilities in PADD V to be over one million bpd, nearly half of which are rail-to-barge facilities in Washington and Oregon. As described in the scenarios at the beginning of this report, this rail offload capacity could eventually be sufficient to fulfill all potential bitumen blend demand in PADD V.

In the short term, crude-on-rail shipments to PADD V and the associated construction of rail offload infrastructure will be driven primarily by the present surge in LTC, particular from the Bakken region in North Dakota. Generally speaking, more rail offload capacity will become available to receive tar sands crude after 2030.

Figure 5: Crude production projections for U.S. tight oil and tar sands crudes (thousand bpd) <sup>5</sup>

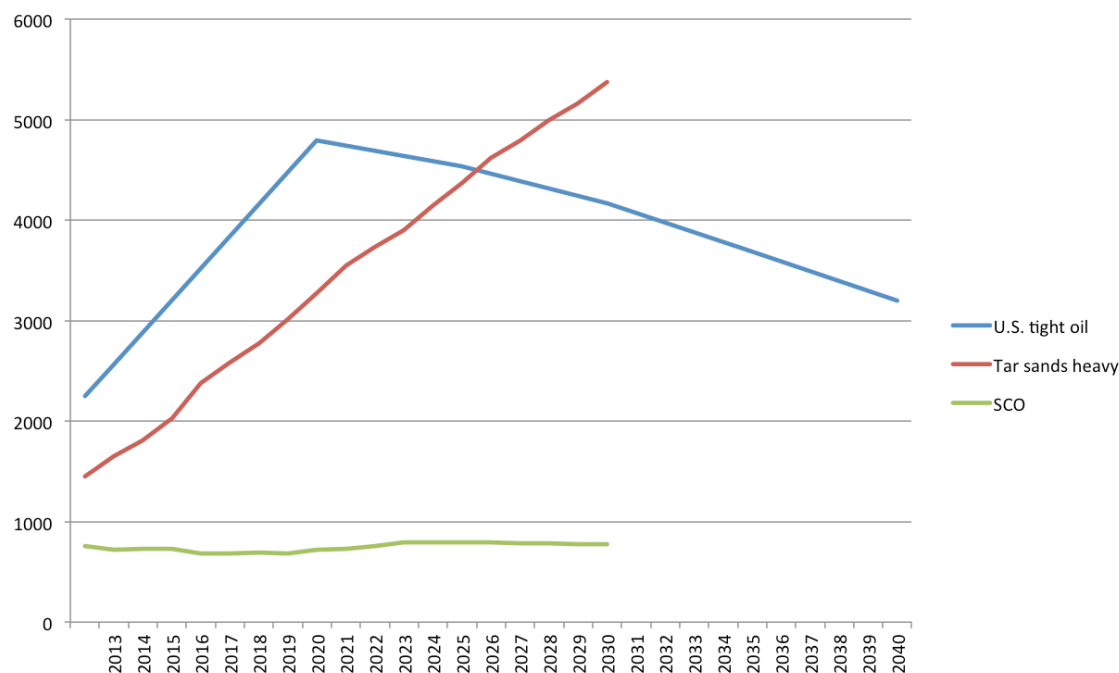
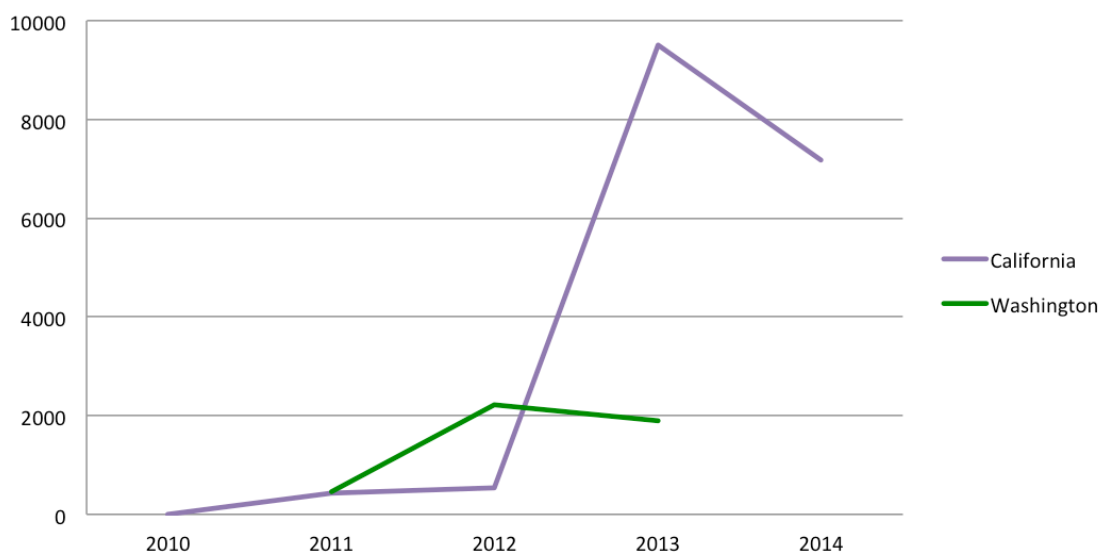


Figure 6: Total known Canadian crude-on-rail shipments to PADD V, 2010-2014 YTD (bpd) <sup>6</sup>



<sup>5</sup> Compiled by Borealis based on data from Energy Information Administration, Annual Energy Outlook 2014 and Canadian Association of Petroleum Producers, Western Canadian Crude Oil Supply Forecast 2014 – 2030.

<sup>6</sup> Compiled by Borealis based on information from the Canadian National Energy Board (NEB) and the California Energy Commission, Energy Almanac. Extrapolated data for Washington in 2010 and 2014 YTD is unavailable.

### 3.4 Synthetic Crude Oil (SCO)

Tar sands-derived Synthetic Crude Oil (SCO) production is not expected to grow by much. The Canadian Association of Petroleum Producers (CAPP) predicts only a modest 60,000 bpd (8.2%) increase in production from 2013 to 2030.<sup>7</sup> This is in part due to the tight oil boom in the U.S.<sup>8</sup> While more expansion on top of this is theoretically possible, such scenarios have not been cited since before the oil shale boom.

Compared to Washington and Texas, there is far greater potential demand for SCO in Texas (SCO and Bakken oil may account for 20% of the products shipped on the proposed Keystone XL pipeline),<sup>9</sup> the U.S. East Coast (served by crude-on-rail), and Asia (which would be served if Kinder Morgan TME and/or Enbridge Northern Gateway pipelines are built), particularly Japan and to a lesser extent South Korea and China. Purvin & Gertz estimates that Japan should be able to process up to 500,000 bpd of SCO, while South Korea should be able to take up to 180,000 bpd and China could potentially take up to 150,000 bpd.<sup>10</sup> And, whereas North American refineries have the flexibility to recycled diluent (condensates) found in Dilbit, Asian refineries are more likely to prefer Synbit (a mixture of bitumen and SCO).<sup>11</sup> Furthermore, these condensates will feed into the light refining capacity, further reducing the need for additional SCO at west coast refineries.

There is strong consensus amongst analysts that the abovementioned facts leave little chance of much increase in SCO shipments to PADD V beyond what Kinder Morgan for example is already banking on.

Finally, not all refineries are capable of taking SCO. Most importantly, refineries with cokers or asphalt production cannot use SCO except perhaps to fill other process units.<sup>12</sup> According to Wood Mackenzie, “Refineries with FCC cracking units typically face a technical limit on the capability to process SCO due to the volume of light ends produced in the FCC due to vacuum gasoil (VGO) properties in SCO.”<sup>13</sup> JACOBS consultancy similarly describes SCO as having a “high volume of low quality feedstock for catalytic cracking refineries”, as well as the “poor quality distillates limit many refiners [use of SCO] to 10% or less of crude diet.”<sup>14</sup> The best fit for refining SCO therefore are non-coking refineries with fluid catalytic cracking (FCC) units.<sup>15</sup> Essentially Wood Mackenzie uses this fact to estimate the total extra demand for SCO on the west coast which could be filled in the event of pipeline expansion to be approximately 90,000 bpd.<sup>16</sup> We estimate the non-coking FCC capacity in PADD V to be approximately 180,000 bpd. This represents an upper ceiling for the amount of SCO that could

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<sup>7</sup> CAPP, “Crude Oil Forecast, Markets & Transportation”, June 2014.

<sup>8</sup> Rodgers Oil and Gas Consulting, “Part II: North American Tight Oil Economics and Fiscal Competitiveness – Play Economics and Supply Prices”, April 4, 2013.

<sup>9</sup> IHS CERA, “The Role of the Canadian Oil Sands in the US Market: Energy Security, Changing Supply Trends, and the Keystone XL Pipeline”, June 2011.

<sup>10</sup> Purvin & Gertz Inc., “Oil Sands Products Analysis for Asian Markets”, April 15, 2005.

<sup>11</sup> Wood Mackenzie, “A Netback Impact Analysis Of West Coast Export Capacity”, produced for Alberta Department of Energy, December 2011.

<sup>12</sup> Oil & Gas Journal, “SPECIAL REPORT: Markets evolving for oil sands bitumen, synthetic crude”, July 7, 2008.

<sup>13</sup> Wood Mackenzie, “A Netback Impact Analysis Of West Coast Export Capacity”, produced for Alberta Department of Energy, December 2011.

<sup>14</sup> JACOBS, “Bitumen to Finished Products”, presented by Gerald W. Bruce, Jacobs Canada Inc., to Canadian Heavy Oil Association Technical Luncheon, Calgary, Nov 9, 2005.

<sup>15</sup> Purvin & Gertz, “Market Development for Western Canadian Crude Oil”, June 2008.

<sup>16</sup> Wood Mackenzie, “A Netback Impact Analysis Of West Coast Export Capacity”, produced for Alberta Department of Energy, December 2011. (See tables 16.0 and 17.0, and Figures 17 and 18)

possibly be utilized; however, we recognize that this figure is not grounded in economic reality and such a high level of utilization is not cited in any other study.

### 3.5 Data tables

Data compiled by Borealis from U.S. Energy Information Administration (Company Level Imports and Annual Energy Outlook), Rystad Energy, Canadian Association of Petroleum Producers, Oil and Gas Journal, Canadian National Energy Board, Muse Stancil, Wood Mackenzie, Kinder Morgan and other sources.

Table 1: Projection figures cited or discussed in this report

Source of estimate	California			Washington			Total		
	Bit. Blend	SCO	Sub-total	Bit. Blend	SCO	Sub-total	Bit. Blend	SCO	Total
Current (2013)	42.6	0.1	42.7	22.6	34.5	57.1	65.2	34.6	99.8
Apportionment-based estimate							86.5	52.4	138.9
Muse Stancil (no Northern Gateway, 2016)				46.0	62.2	108.2			
Muse Stancil (no Northern Gateway, 2025)				42.9	62.2	105.1			
Wood Mackenzie (no Northern Gateway) *								53.1	
Wood Mackenzie (with Northern Gateway) *								92.6	
Kinder Morgan TME committed shippers-based estimate *							419.0	75.3	494.3
Kinder Morgan TME capacity							572.3	91.2	663.5
Muse Stancil	450.0			50.0			500.0		
University of Calgary **	300.0			50.0			350.0		
Offsetting imports methodology (2020)	394.3			22.3			416.6		
Offsetting imports methodology (2030)	519.2			31.2			550.4		
Offsetting imports methodology (2040)	616.6			38.9			655.5		
Coking capacity methodology (2020)	522.0			100.8			622.8		
Coking capacity methodology (2030)	567.3			104.1			671.5		
Coking capacity methodology (2040)	603.9			107.1			711.0		
Coking capacity ***	655.8			108.3			764.0		
Non-coker FCC capacity		97.8			81.4			179.2	

\* Combined with SCO projections for 2030



\*\* Combined with Muse Stancil estimate for Washington

\*\*\* Adjusted to include diluent of bitumen blend

Table 2: Data used in *offsetting imports methodology* (PADD V heavy crude imports and production)

Year	Heavy imports (API<25)	CA heavy production	AK heavy production
2011	379.7	389.4	39.2
2020		308.7	37.0
2030		206.0	20.5
2040		123.8	6.0

Table 3: Bitumen blend adjustment

Year	Bitumen blend as a percentage of western Canadian heavy crude production
2020	90.1%
2030	94.6%
2040	96.6%

### 3.6 Kinder Morgan Trans Mountain Expansion

There are four main pipeline proposals. Wood Mackenzie analyst Michael Wojciechowski predicts that Trans Mountain Expansion will be built first, Northern Gateway will be last and either Keystone XL or Energy East won't get built.<sup>18</sup>

Kinder Morgan is proposing to increase the capacity of its Trans Mountain pipeline from 300,000 to 890,00 bpd. The company projects that approximately 60% of the expanded capacity will be used for transporting heavy crude oil and has proposed a 80%-20% capacity split between committed shippers and uncommitted volumes.<sup>20</sup> A small amount will be used to transport petroleum products (under 50,000 bpd in 2012<sup>21</sup>).

<sup>18</sup> Comments made by Wood Mackenzie analyst Michael Wojciechowski at a press briefing in Calgary on June 20, 2014. As reported in Business in Vancouver, "Trans Mountain poised to finish first ahead of Northern Gateway in pipeline race: Wood Mac", June 23, 2014.

<sup>20</sup> Trans Mountain Pipeline ULC, "Responses to Canadian Association of Petroleum Producers (CAPP), Information Request No. 1", January 10, 2013.

<sup>21</sup> Kinder Morgan, "Trans Mountain Pipeline System", Oil Sands Product Forum, April 16, 2013.

The existing pipeline is currently at full capacity, and in fact is generally over-committed. As disclosed by the company, from January 2012 to March 2013, apportionment levels (where each Land Destination shipper is receiving fewer barrels than nominated) have averaged 71%.<sup>22</sup> Similarly, the NEB reported in March 2014 “The Trans Mountain Pipeline has reported apportionment levels near 70 per cent since mid-2011, meaning that producers have only been able to move about 30 per cent of their desired volumes on that pipeline.”<sup>23</sup> We use this figure, coupled with actual trade volumes, to estimate the current demand for bitumen blend to be about 85,000 bpd.

At least thirteen shippers have signed binding contracts with Kinder Morgan, should the project be approved, totalling 708,000 bpd<sup>27</sup> (with the remaining 182,000 bpd being uncommitted volumes).

- BP Canada Energy Trading Company
- Canadian Natural Resources
- Canadian Oil Sands Limited
- Cenovus Energy Inc.
- Devon Canada Corporation
- Husky Energy Marketing Inc.
- Imperial Oil Limited
- Nexen Marketing Inc.<sup>28</sup>
- Statoil Canada Ltd.
- Suncor Energy Marketing Inc.
- Suncor Energy Products Partnership
- Tesoro Refining & Marketing Company
- Total E&P Canada Ltd.

### 3.7 Heavy vs light oil upgrade plans

At present, no west coast refinery has announced upgrade plans in order to directly process more heavy crude.<sup>31</sup> In California, this is partly due there already being sufficient heavy crude refining capacity, some of which is currently underutilized. It is also partly due to the recent abundance of domestic light crudes now available. But most importantly, such upgrades are expensive.

Upgrading refineries to be able to process dilbit can be very complex and expensive and the costs are very much dependent on the size of the existing plant and the equipment already in use. It has been estimated that a new

<sup>22</sup> Chevron Canada Limited, "Application for a Priority Destination Designation" (application to the National Energy Board), June 19, 2012.

<sup>23</sup> National Energy Board, "Canadian Energy Dynamics 2013 - Energy Market Assessment", March 2014. ISSN 2292-8308. Available at <http://www.neb-one.gc.ca/clf-nsi/rnrgynfntn/nrgyrprt/nrgydynmcs/cndnnrgydynmcs2013/cndnnrgydynmcs2013-eng.html>

<sup>27</sup> Kinder Morgan Canada Inc., Trans Mountain pipeline website, "Commercial Support", <http://www.transmountain.com/commercial-support>, accessed September 2014; Kinder Morgan Energy Partners, L.P., press release, "Trans Mountain Files Facilities Expansion Application with the National Energy Board", Dec. 16, 2013.

<sup>28</sup> Nexen is owned by the Chinese company CNOOC.

<sup>31</sup> Based on analysis of data from Hart Energy.

medium-size coking unit alone can cost \$2 billion.<sup>32</sup> However, upgrades can also be more expansive than that. Husky's planned upgrade for its Ohio refinery was pegged at \$2.8 billion,<sup>33</sup> while the four-year upgrade of the BP refinery in Whiting, Indiana has required an investment of up to \$4 billion.<sup>34</sup>

Chevron describes additional facilities at its Burnaby refinery to handle heavy sour crude as being "very costly to install", adding that the expenses are "extreme" and that that relatively little detailed study has been carried out to assess the need and costs. A preliminary assessment by the company pegged the costs as upwards of \$500 million,<sup>35</sup> a very high price for one of the smallest-capacity refineries on the west coast.

On the other hand, there is a growing appetite to modify refineries to take more domestic light, tight crude (LTC). Shell is planning a \$450,000 modification at its Martinez refinery in California to permanently shut down one of its two coker units and switch from its current slate of heavy and intermediate crudes to lighter crudes, without changing its overall capacity of 165,000 bpd. The company estimates this switch will result in 700,000 metric tons per year fewer GHG emissions. Construction will run from mid-2016 to 2018.<sup>36</sup> A Baker & O'Brien study commissioned by Consumers and Refiners United for Domestic Energy estimates that the average cost of projects to take more light, tight crude (LTC) is about \$250 million to \$1.2 billion, while simple debottlenecking to take 10-20% more light crude would incur even more modest investment.<sup>37</sup>

**Table 4: Cost comparison of upgrades to take more light versus heavy crude**

	Cost of modifications to refine more light crude (\$million)	Cost to add a coker to process tar sands bitumen (\$million)
Typical cost	500	2,000
Range of examples cited in this report	250 to 1,200	500 to 4,000
Typical investment payback period	5 years	20 years <sup>38</sup>

Baker & O'Brien calculates that US refineries have announced projects that would add up to 1.1 million bpd of LTC capacity by 2019. Meanwhile, it concludes that refineries in PADD V, especially California, are less likely to

<sup>32</sup> Canada's Oil Sands: Opportunities and Challenges to 2015. 2004. National Energy Board; Financial Post, "Can pipelines in Eastern Canada boost refineries?", April 18, 2013.

<sup>33</sup> Calgary Beacon, "\$2.8 billion upgrade to Ohio heavy oil refinery studied by Husky Energy", December 16, 2011.

<sup>34</sup> BP expects Whiting refinery upgrade benefits in 2014. 2013. Reuters

<sup>35</sup> Chevron Canada Limited, "Schedule A: Evidence in Support of the Priority Destination Designation Application", June 19, 2012.

<sup>36</sup> Martinez News-Gazette, "Shell Martinez to shut down flexicoker, reduce green house gas emissions", May 18, 2014. Available at <http://martinezgazette.com/archives/14673>

<sup>37</sup> Baker & O'Brien, Inc., "An Analysis of U.S. Light Tight Oil Absorption Capacity", September 24, 2014; See also Oil & Gas Journal, Oct. 13, 2013, page 24 ("US refiners could process more light, tight crudes, study finds").

<sup>38</sup> Canadian Fuels Association, "The Economics of Petroleum Refining", December 2013. ("Refining Canadian bitumen [...] would first require substantial investment in new heavy conversion refining capacity [...] The states are high, with a payback period that is 20 to 30 years." Note: technically this refers to standalone upgraders, but the technology is similar).

expand compared to other regions due to limited product supply disposition choices, lack of connecting pipeline infrastructure and state-level regulatory and permitting pressures.<sup>39</sup>

Clearly, the national trend is towards taking more light, not heavy crude, and in California the status quo is more of the norm. Although the trend could change, for the sake of this analysis we assume no increase in ultra heavy (coking) capacity.

Note: The only publicly announced non-light upgrade project is by Chevron's Richmond refinery, which is planning to increase capacity at its fluid catalytic cracker's hydrotreater and sulfur-recovery system to run higher-sulfur oils. Crude blends will be able to contain as much as 3 percent sulfur, up from a limit of about 2 percent currently. The company claims that this would not change the slate of the crudes that they process,<sup>40</sup> but critics argue that higher-sulfur crude capacity will indirectly lead to greater intake of tar sands heavy oil which typically contains higher levels of sulfur. We have not included Chevron's plans in our analysis because it does not effect overall heavy crude capacity in California according to standard quantifiable metrics.

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<sup>39</sup> Baker & O'Brien, Inc., "An Analysis of U.S. Light Tight Oil Absorption Capacity", September 24, 2014; See also Oil & Gas Journal, Oct. 13, 2013, page 24 ("US refiners could process more light, tight crudes, study finds").

<sup>40</sup> Chevron, "Chevron Richmond Refinery Revised Renewal Project: Conditional Use Permit Application – Project Description", May 23, 2011. Available at <http://www.chevronmodernization.com/wp-content/uploads/2011/07/ChevronSubmittal1.pdf>